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THE STATE OF SOUTH CAROLINA
In The Court of Appeals

APPEAL FROM THE ADMINISTRATIVE LAW COURT

Ralph K. Anderson III, Administrative Law Judge

Case No. 10-ALJ-17-0270-CC

Duke Energy Corporation.....Appellant,

v.

South Carolina Department of Revenue.....Respondent.

RECORD ON APPEAL

VOLUME XV

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(b) Nuclear capability and related generation for 1992 and projected for 1993 give no effect to the joint ownership of the Catawba Nuclear Station. (See "Joint Ownership of Facilities.")

(c) Includes Bad Creek and Jocassee pumped storage hydroelectric stations at licensed generating capabilities of 1,065,000 KW, and 610,000 KW, respectively.

(d) Excludes firm purchases. (See"Energy management and Future Power Needs.")

Nantahala Power and Light Company (NP&L), which operates 11 hydroelectric stations and buys supplemental power to provide service to its 51,000 mostly residential customers located in five counties in western North Carolina, operates as a separate subsidiary of the Company. The Company is supplying supplemental power to NP&L under the terms of an interconnect agreement approved by the Federal Energy Regulatory Commission (FERC).

The Company reached a bulk power sale agreement in 1987 to provide Carolina Power and Light (CP&L) 400 MW of electricity for a six-year period beginning in 1992. This proposed agreement was accepted for filing by FERC in 1989. The Company and CP&L subsequently disagreed on whether the agreement was binding, and litigation was initiated regarding this dispute. The Company and CP&L have settled the matter and amended the agreement to reflect that settlement, which basically provides for an 18-month deferral in the implementation of the six-year contract period. The amended agreement has been filed with FERC which has taken the action necessary for the agreement to become effective. However, FERC approval of the amendment is being contested by other parties.

Statistics compiled by the Nuclear Regulatory Commission (NRC) on multi-unit nuclear plants indicate that the Company's three nuclear were ranked first, second and third in efficiency in converting uranium energy to electricity for 1991, the latest year for which figures are available. According to industry statistics published in 1992, the Company ranked second in the nation in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Published rankings indicate that individual units at Marshall Steam Station and Belews Creek Steam Station ranked as second and sixth most efficient in the nation in 1991.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. On July 14, 1992, the Company experienced its all-time peak load of 14,763,000 KW during unusually hot weather. A new winter peak load of 13,314,000 KW occurred on February 19, 1993. The 1991-1992 winter peak load of 13,001,000 KW occurred on January 16, 1992. The Company currently forecasts a 2.3% compound annual growth in peak load through 2006. This amount is not

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reduced by those future demand-side management program contributions considered resources for meeting peak demand. (See "Energy Management and Future Power Needs.")

RATE MATTERS

The North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSCSC) must approve the Company's rates for retail sales within the respective states. FERC must approve the Company's rates for sales to wholesale customers. Constituent entities of NCMPA, NCEMC, Saluda and PMPA are served under contractual arrangements between such entities and the Company.

Rate requests filed by the Company in its most recent general rate case in 1991 with the NCUC, PSCSC and FERC were principally designed to reflect the Company's investment in the Bad Creek Hydroelectric Station. Rate orders issued by the NCUC and PSCSC in November, 1991 recognized costs of the Bad Creek Hydroelectric Station, including an amortization of costs deferred between commercial operation and the rate order, which the Company had requested. The wholesale customers challenged the Company's proposed rate increase and in 1991 FERC issued an order that accepted the Company's proposed rates for filing. A negotiated settlement with these customers, which is consistent with the increase in the retail rates, was approved by FERC and became effective in April
1992.
[HARDCOPY PAGE 3]

In its most recent general rate case, the NCUC authorized a jurisdictional rate of return on common equity of 12.50% and the PSCSC authorized a jurisdictional rate of return on common equity of 12.25%.

The Company canceled certain nuclear projects in prior years, including the Cherokee Nuclear Station, citing a slower growth in the demand for electricity, a changing pattern in that growth and more economical means of meeting such changed pattern as reasons for such cancellation. The NCUC and PSCSC have authorized the Company to recover over a 10-year period, beginning in 1983, the costs of abandonment of the Cherokee Nuclear Station. Similarly, rates including such abandonment costs are also in effect in the Company's wholesale jurisdiction. However, no return was allowed on the unamortized portion of such costs. (See Note 11, "Notes to Consolidated Financial Statements.")

The North Carolina Supreme Court on April 22, 1992 remanded for the second time the Company's 1986 rate order to the NCUC. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return of 13.2 percent on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986

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rate order. The NCUC issued an order dated October 26, 1992, authorizing a 12.8 percent return on common equity for the period October 31, 1986 through November 11, 1991, that resulted in a refund to North Carolina retail customers in 1992 of approximately $95 million, including interest.

FUEL COST ADJUSTMENT PROCEDURES

The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The NCUC ordered the Company to follow these procedures in its August 1986 order, which was effective for periods beginning January 1, 1986. The prospective adjustment in rates of past over-or under-recovery of fuel costs was challenged in the North Carolina courts. North Carolina adopted legislation assuring the legality of such adjustments, which contains a sunset provision effective June 30, 1997.

CONSTRUCTION WORK IN PROGRESS (CWIP)

The NCUC is permitted in its discretion to include CWIP in rate base after giving consideration to the public interest and the Company's financial stability. The PSCSC may include CWIP in rate base in its discretion.

ENERGY MANAGEMENT AND FUTURE POWER NEEDS

The Company's strategy for meeting customers' present and future energy needs is comprised of three components: demand-side options, purchased-power options and supply-side options. By utilizing these options, the Company expects to maintain a summer reserve margin of approximately 20% to 25% of its anticipated peak load requirements through 1995.

Demand-side management programs are an integral part of meeting the Company's future power needs. These programs benefit the Company and its customers by providing for load control through interruptible control features and by promoting energy efficiency. In return for participation in demand-side management programs, the Company's customers may be eligible to receive various incentives which help to reduce their electric bills. Demand-side management programs such as Industrial Interruptible Service and Residential Load Control will be used to control the rate of growth in peak demand. Energy efficiency programs relating to commercial and industrial lighting and motors, high efficiency heat pumps and high efficiency air conditioners are other examples of current demand-side management programs. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The

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costs deferred, including the return, were approximately $18 million in 1992. The Company continues to engage in a comprehensive energy management program as part of its Integrated Resource Plan. Integrated Resource Planning is the process used by utilities to evaluate a variety of resources to cost effectively meet customer energy-service needs. The PSCSC has issued an order approving the Company's 1992 Integrated Resource Plan as reasonable, and approving a "shared savings" proposal for accomplishments made in the Company's demand-side management programs. A similar plan is pending
[HARDCOPY PAGE 4]

approval by the NCUC. The Company's current plan reduces supply side requirements in excess of 2,200 MW by the year 2000 due to the Company's effective use of demand side options.

The purchase of capacity and energy is also an integral part of meeting future power needs. The Company currently has under contract 500 megawatts of capacity from other generators of electricity.

The Company's construction program and the estimated construction costs set forth below are subject to continuing review and are revised from time to time in light of changes in load forecasts, the Company's financial condition (including cash flow, earnings and levels of rates), changing regulatory and environmental standards (see "Regulation--Environmental Matters") and other factors.

Projected construction and nuclear fuel costs, excluding costs related to portions of the Catawba Nuclear Station owned by the Other Catawba Joint Owners, for each of 1993, 1994 and 1995 and for the three-year period 1993-1995, as now scheduled, are as follows (in millions of dollars):

Type of Facilities	1993	1994	1995	Total
Generation	$265	$509	$425	$1,199
Transmission	50	56	56	162
Distribution	229	241	249	719
Other	95	104	121	320
Total	$639	$910	$851	$2,400
Nuclear Fuel	$143	$155	$129	$ 427

The Company's procedures for estimating construction costs (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs and allowances for inflation.

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The construction of a combustion turbine facility is scheduled to begin in spring 1993 in Lincoln County, North Carolina. The Lincoln Combustion Turbine Station will be able to accommodate 16 combustion turbines with a total generating capacity of 1,184 megawatts. The estimated total cost of the project is approximately $500 million. Current plans are for the first four units to begin commercial operation in 1995 and the remaining twelve by the end of 1996. The Lincoln facility will provide capacity at periods of peak demand. During 1991, the NCUC granted the Certificate of Public Convenience and Necessity and the North Carolina Division of Environmental Management issued a final air permit for the facility. Certain parties appealed the issuance of the air permit. Management believes the plaintiffs will not prevail on appeal.

The Company has undertaken a Plant Modernization Program (PMP) to improve the efficiency and reliability of 15 older coal-fired generating units. These units, once modernized, will help the Company meet anticipated future demand. The cost of this program is estimated to average approximately $200-$300 per installed KW, a fraction of the cost of building new plants. As of December 31, 1992, ten coal-fired units with a generating capability of 1,083,000 KW had been returned to the system. It is anticipated that two additional coal-fired generating units with generating capability of 171,000 KW will be returned to the system during 1993. The three units remaining in the PMP after 1993 represent 146,000 KW of generating capability.

JOINT OWNERSHIP OF FACILITIES

In order to reduce its need for external financing, the Company, through several transactions beginning in 1978, sold an 87 1/2% undivided interest in the Catawba Nuclear Station to the Other Catawba Joint Owners.

These transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use (whether or not the facility is generating electricity) that portion of the capacity not then contractually required by the respective participants, and provide supplemental as required by the purchasers to enable

[HARDCOPY PAGE 5]

them to provide service on a firm basis. The transactions also include a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station of the Company, which provides for an exchange of 50% of each Other Catawba Joint Owner's retained capacity from its ownership interest in the Catawba units for like amounts of capability

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and output from units of the McGuire Nuclear Station. The implementation of the reliability exchange has not had nor does the Company anticipate that such implementation will have a material effect on earnings.

The Other Catawba Joint Owners and the Company are involved in various proceedings related to the Catawba joint ownership agreements. The basic contention in each proceeding is that certain calculations effecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the Other Catawba Joint Owners which have been approved by the Company's retail regulatory commissions (see Note 3, "Notes to Consolidated Financial Statements"). Although the Other Catawba Joint have not fully quantified the dollars associated with the presently outstanding proceedings, information associated with these proceedings indicates that the amount in contention could be as high as $360 million through December 31, 1992. Arbitration hearings were held in 1992 involving substantially all of the disputed amounts. The ultimate resolution of these matters cannot presently be determined; however, the Company is of the opinion that it has properly interpreted these agreements and that these costs would be included and recovered as part of the purchased capacity levelization consistent with prior orders of the retail regulatory commissions. Therefore, the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The levelized recovery of purchased power obligations under contracts with the Other Catawba Joint Owners is expected to result in amounts collected in rates in excess of payments by the Company for such power by approximately $211 million over the next three years, assuming that contingencies discussed in the paragraph above are resolved in the Company's favor.

FUEL SUPPLY

The Company presently relies principally on nuclear and coal for the generation of electric energy. The Company's reliance on oil and gas is minimal.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

Generation by Source

Year Ended December 31

	1992	1991	1990
Coal	36.7%	34.2%	36.9%
Nuclear	61.0	63.8	60.5

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Oil and Gas	-	-	-
All Fuels (cost based on weighted average average	97.7	98.0	97.4
Hydroelectric(*)	2.3	2.0	2.6
	100.0%	100.0%	100.0%

(TABLE CONTINUED)

Average Cost per Million BTU on a Burned Basis

Year Ended December 31

	1992	1991	1990
Coal	174.10 cents	179.29 cents	180.61 cents
Nuclear	52.52	55.00	55.65
Oil and Gas	-	-	-
All Fuels (cost based on weighted average	96.05	96.48	101.14

(*) Generating figures are net of that output required to replenish pumped storage units during off-peak periods.

COAL

The Company obtains a large amount of its coal under long-term supply contracts with mining operators utilizing both underground and surface mining. The Company has on hand an adequate supply of coal.

The Company's long-term supply contracts, all of which have price adjustment and price renegotiation provisions, have expiration dates ranging from 1993 to 2003. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers. However, due to the Clean Air Act Amendments of 1990, fuel premiums may be required as contracts are for renewed. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southernwestern Virginia.

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The average sulfur content of coal being purchased by the Company is approximately 1%. Such coal meets the current emission limitation for

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sulfur dioxide for existing facilities. (See Regulation-Environmental Matters-AIR QUALITY.)

NUCLEAR

Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrate, the conversion of uranium concentrate to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations. Based upon current projections, these contracts will meet the Company's requirements through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1996	1994	1995	1997
McGuire	1996	1994	1995	1998
Catawba	1996	1994	1995	1998

Uranium material requirements will be met through various supplier contracts, with uranium material produced primarily in the U.S., Canada and Australia. The Company believes that it will be able to renew contracts as they expire or to enter into similar contractual arrangements with other nuclear fuel materials and services suppliers. Short-term requirements have been and will be fulfilled with uranium spot market purchases.

The Company purchased uranium material during 1992 at an average price of approximately $29 per pound. The Company's material nuclear supply contracts generally contain force majeure provisions.

The Nuclear Waste Policy Act of 1982 requires that the Department of Energy (DOE) begin disposing of spent fuel no later than January 31, 1998. The Company has entered into the required contracts with the DOE for the disposal of nuclear fuel and began making a payments in July 1983 for disposal costs of fuel currently being utilized. These payments combined with a one-time payment for disposal costs of fuel consumed prior to April 7, 1983 have totaled about $500 million through 1992. In November 1989, the DOE released a report which indicated that it expects that a facility for spent fuel disposal will not be available until the year 2010. The DOE stated further that it planned an initiative to establish a monitored retrievable storage facility, with a target operation date of 1998, for earlier acceptance of spent fuel utilities. The Company believes that it will be able to provide

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adequate on-system storage capacity until such time as the DOE begins receiving spent fuel.

REGULATION

The Company is subject to the jurisdiction of the NCUC and the PSCSC which, among the other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC, the Environmental Protection Agency (EPA) and state environmental agencies and to the jurisdiction of the NRC as to design, construction and operation of its nuclear power facilities. The Company is exempt from regulation as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA), except with respect to the acquisition of the securities of other public utilities.

ENVIRONMENTAL MATTERS

The Company is subject to federal, state, and local regulations with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. North Carolina has enacted a declaration of environmental policy requiring all state agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generations facilities. South Carolina law also requires consideration by the PSCSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed major utility facilities, which include

[HARDCOPY PAGE 7]

certain generation and transmission facilities. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. The Company's 1993-1994 construction program includes costs for environmental protection (as now defined by FERC) which are estimated to be approximately $62.2 million, including $20.6 million 1993 and $41.6 million in 1994. These costs include expenditures to begin compliance with the Clean Air Act Amendments of 1990. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. Therefore, the Company may have to revise these estimates in response to developments in these and other areas.

AIR QUALITY

The Clean Air Act Amendments of 1990 require a two phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national objective of clean air and has already reduced emissions through the use of low-sulfur coal in its fossil plants, through efficient operations and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. The Company is considering all of the alternatives to devise an optimum strategy for compliance with more stringent Phase II requirements at the least cost. A preliminary strategy, which is currently being reviewed, indicates an estimated cost of approximately $1 billion in capital and $81 million in annual operating and maintenance costs (in year 2000 dollars) for compliance with Phase II requirements and other provisions of the Act. The Company is currently working on a detailed compliance plan that must be filed and approved by the EPA by 1996.

WATER QUALITY

The Federal Water Pollution Control Act Amendments of 1987 (otherwise known as the "Clean Water Act") require permits to ensure compliance with its provisions. The Company received such permits and is in the process of renewing these permits for several facilities.

OTHER ENVIRONMENTAL REGULATIONS

Contingencies associated with environmental matters are principally related to possible obligations to remove or mitigate the effects on the environment resulting from the disposal of certain substances at contamination sites.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as "Superfund," requires any individual or entity which may have owned or operated a contaminated site, as well as transporters or generators of hazardous wastes which were sent to such site, to assume joint and several responsibility for remediation of the site. The Company has been notified that it is a contributor at sites in North Carolina and West Virginia. The Company's relative contribution to such sites is unknown at this time. The Company is a de minimus contributor at a site in Pennsylvania. The Company is also a contributor at certain comparable contamination sites which may in some cases be remediated in accordance with state acts which are similar to CERCLA. While the total cost of remediation at these sites may be substantial, the Company shares probable liability with other potentially responsible parties. Other state contamination sites relate to the Company's involvement in manufactured gas plant sites prior to the early 1950s, some of which are still owned by the Company and some of which are now owned by third parties. Based on the information known to the Company at this time, management is of the

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opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

GENERAL

Over the past few decades, the issue of the possible health effects of electric and magnetic fields has generated a number of generally inconclusive studies, some public concern and litigation as well as legislative action in some states regarding high voltage transmission lines. The impact of this issue on the Company cannot presently be determined.

NUCLEAR FACILITIES

The Company's nuclear facilities are subject to continuing regulation by the NRC.

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The steam generators at the McGuire and Catawba Nuclear Stations have experienced stress corrosion cracking in their tubes. Stress corrosion cracking is a phenomenon that typically occurs in tight U-bends, at tube support plates, and where tubes are attached to the tube sheets. Stress corrosion cracking has been identified as a problem in steam generators of certain designs, including those at the McGuire and Catawba Stations. Both primary side and secondary side cracking and corrosion have been observed in the steam generators at the McGuire and Catawba Stations. Both primary side and secondary side cracking and corrosion have been observed in the Steam generators at the McGuire and Catawba stations In addition, recent inspections at McGuire Units 1 and 2 have revealed a different type of secondary side stress corrosion cracking in the free-span area of the steam generator tubes located on the "cold-leg" side of those Units (cold-leg free-span cracking).

The Company conducts tests at each refueling outage to determine the extent of stress corrosion cracking during the preceding fuel cycle.

The steam generators at Catawba Unit 2 have certain design differences from those at Catawba Unit 1 or either McGuire Unit, but it is too early in the life of Catawba Unit 2 to determine the extent to which stress corrosion cracking will be a problem. Follow-up testing is being conducted on Catawba Unit 2 which began a refueling outage in January 1993. Catawba Unit 2 is scheduled to return to service in April 1993.

Although the Company has taken steps to mitigate the effects of stress corrosion cracking in the McGuire and Catawba steam generators tubes, including examining the steam generator tubes at each refueling outage,

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tube, plugging tube sleeving, more stringent water chemistry control, shot peening, and tight u-bend heat treatment, further stress corrosion cracking in the McGuire Units 1 and 2 and Catawba Unit I steam generators appears likely. Potential consequences of future stress corrosion cracking include extensive tube plugging and sleeving, additional water chemistry control, additional inspections and testing resulting in longer outages, mid-cycle outages, reduction in plant output, requests for license amendments, and replacement of the steam generators well short of their 40-year design life. The Company has compared the cost of continued repair of the steam generator with the cost of early steam generator replacement and has determined that for McGuire Units 1 and 2 Catawba Unit 1, the most cost-effective alternative is to replace the steam generators as soon as it is feasible to do so.

The Company has begun planning for the replacement of steam generators and has set the following schedule: McGuire Unit 1 - 1995; Catawba Unit 1 - 1996; McGuire Unit 2 - 1997. The order of replacement is subject to change based on performance of the existing steam generators and on the overall performance of the three units. The Company has signed an agreement with Babcock & Wilcox International to purchase 12 replacement steam generators for the McGuire and Catawba Stations. Each unit's steam generator replacement is expected to take approximately four months and cost approximately $200 million, excluding the cost of replacement power and without consideration of reimbursement of applicable costs by the Other Catawba Joint Owners for the Catawba Unit 1. Stress corrosion problems are excluded under the nuclear insurance policies. Because Catawba Unit 2 has not shown the degree of stress corrosion cracking which has occurred in McGuire Units 1 and 2 and Catawba Unit 1, the Catawba Unit 2 steam generators have not been scheduled for replacement.

The Company, on its own behalf and, in connection with the Catawba Station, on behalf of the Other Catawba Joint Owners, commenced an action on March 22, 1990, in the United States District Court for the District of South Carolina (Charleston Division) seeking damages from Westinghouse Electric Corporation (Westinghouse) for supplying to the McGuire and Catawba Stations steam generators that are alleged to be defective in design, workmanship and materials, and that will require replacement well short of their stated design life. The complaint alleges that at the time the contracts for the nuclear steam supply systems for the McGuire and Catawba Stations were negotiated and executed in the early and mid 1970's, and continuing thereafter, Westinghouse knew, or recklessly disregarded information in its possession, that the steam generators would be susceptible to corrosion and cracking that would cause deterioration and require premature replacement. The complaint further alleges that Westinghouse deliberately concealed such information from the Company and defrauded the Company by falsely representing that the steam generators were designed to last for 40 years.

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The complaint further alleges that Westinghouse engaged in deceptive acts that were intended to prevent the Company from exercising its rights against Westinghouse, and also engaged in a pattern of deceptive acts throughout the domestic and worldwide electric generating industry to the detriment of the Company and others. The complaint contains counts for fraud, violations of the South Carolina and North Carolina Unfair Trade Practice Acts promissory, estoppel and patterns of racketeering activities prohibited by the Racketeer Influenced and corrupt Organization Act (civil RICO). In the action, the Company is seeking a judgment against Westinghouse for damages including the cost of replacement of steam generators, payment for replacement power during outages to accomplish replacement, punitive or treble damages, and attorneys' fees.

The NCR issued a rulemaking in 1988 which requires an external mechanism to fund the estimated cost to decommission the components of a nuclear unit subject to radioactive contamination. The estimated site-specific obligations for decommissioning cost, including cost for plant components not subject to radioactive contamination, total approximately $955 million stated in 1990 dollars. This amount includes only the Company's ownership percentage of 12.5 percent in the Catawba Nuclear Station. The Other Catawba Joint Owners are liable for providing for decommissioning related to their ownership interest in the Catawba Nuclear Station. Effective with the implementation of new retail rates in 1991, the NCUC and the PSCSC granted the Company recovery of the estimated site-specific decommissioning costs through retail rates. It is managements' opinion that the estimated site-specific decommissioning costs being recovered through rates are currently sufficient to provide for the cost of decommissioning, assuming the Company's nuclear plants are not decommissioned prior to the end of their licensed life.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE uranium enrichment plants. Licenses will be subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The Company has reflected the present value of this obligation of approximately $102 million in the 1992 Consolidated Balance Sheets.

The Company maintains nuclear insurance coverage in three areas: liability coverage, property, decontamination and decommissioning coverage, and extended accidental outage coverage to cover increased generating costs and/or replacement power purchases. The Company is being reimbursed by the Other Catawba Joint Owners for certain expenses associated with nuclear insurance premiums paid by the Company.

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Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting nuclear incidents to the full limit of liability of approximately $7.8 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $7.6 billion, which will be increased by $63 million (in 1988 dollars) as each additional commercial nuclear reactor is licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs, and public liability damages exceed primary insurances, licensees may be assessed up to $63 million (in 1988 dollars) for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $63 million amount is subject to indexing for inflation. This amount is further subject to a surcharge of 5 percent (which is included in the above $7.8 billion figure) if funds are insufficient to pay claims and associated costs. If retrospective premiums were to be assessed, the Other Catawba Joint Owners are obligated to assume their pro rata share of such assessment.

The Company is a member of Nuclear Mutual Limited (NML), which provides $500 million in primary property damage coverage for certain of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $29 million. This amount represents 5 times the Company's annual premium to NML.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases $1.325 billion of insurance through NEIL's excess property, decontamination and decommissioning

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liability insurance program. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, the Company will be liable, on a pro rata basis, for additional assessments of up to $45 million. This amount is limited to 7.5 times the Company's annual premium to NEIL for excess property, decontamination and decommissioning liability insurance. The Other Catawba Joint Owners are obligated to assume their pro rata share of any liability for retrospective premiums and other premiums assessments resulting from the NEIL policies applicable to Catawba. The Company has also purchased an additional $400 million of excess property damage insurance for its Oconee and McGuire plants and $765 million for its Catawba plant through a pool of stock and mutual insurance companies.

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In addition to the $1.325 billion in coverage through NEIL's excess property program and the $765 million in excess coverage mentioned above, and in lieu of primary property coverage through NML, the Company has placed $500 million through a pool of stock and mutual insurance companies for primary property insurance coverage associated with its interest in the Catawba Nuclear Station.

The Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. The Oconee, McGuire and Catawba Nuclear Stations are insured for up to approximately $2.5 million, $3.5 million, and $3.5 million per unit per week, respectively, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100 percent for 52 weeks, and 67 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $27 million. This amount represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. The Other Catawba Joint Owners are obligated to assume their pro rata share of any liability for restrospective premiums and other premium assessments resulting from the NEIL policies applicable to the joint ownership agreements.

HYDROELECTRIC LICENSES

The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 Kw, are licensed for a term expiring in 2008. The Company also holds a license for the Keowee-Toxaway Project for a term expiring in 2016, covering the Keowee Hydro Station and the Jocassee Pumped Storage Station for a combined total of 769,500 KW, on the upper tributaries of the Savannah River in northwestern South Carolina. Additionally, the Company is the licensee through 2027 for the Bad Creek Pumped Storage Station which uses Lake Jocassee as its lower reservoir and has a nameplate rating of 1,065,000 KW.
The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

INTERCONNECTIONS

The Company has major interconnections and arrangements with its

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neighboring utilities which it considers adequate for coordinated planning, emergency, assistance, exchange of capacity and energy, and reliability of power supply.

COMPETITION

The Company currently is subject to competition in some area from government-owned power systems, municipally-owned electric systems, rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and PSCSC, respectively, of all areas outside municipalities in such states to power companies and rural electric cooperatives. Substantially all of the territory comprising the

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Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSCSC. In addition, the Company is engaged in continuing competition with various natural gas providers.

The Energy Policy Act of 1992 has far-reaching implications for the Company by moving utilities toward a more competitive environment. Reform of the PUHCA will remove barriers to the Company, allowing it to develop independent electric generating plants in the United States for sales to wholesale customers as well as contract for utility projects internationally, without becoming subject to registration under PUHCA as an electric utility holding company. The Act requires transmission for third parties to wholesale customers, provided the reliability of service to the utility's local customer base is protected and the local customer base does not subsidize the third party service. The Company presently believes this legislation will lead to no appreciable erosion in its customer base because its rates are regionally and nationally competitive.

NON-UTILITY ACTIVITIES

The Company is engaged in a variety of non-utility operations, most of which are organized in separate subsidiaries, including real estate development and forest management, marketing of electrical appliances, management of passive financial investments, developing and investing in electric generation facilities outside the Company's service area and providing engineering and technical services.

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Subsidiary and non-utility operations contributed $29.9 million of total Company earnings in 1992.

In February 1993, Duke Energy Corp. announced an agreement to enter into a strategic alliance with J. Makowski & Company (Makowski), a developer of natural gas-fired electric projects. The alliance is expected to include an agreement by Duke Energy Corp. to make an investment in Makowski convertible preferred stock.

The Company, through its subsidiaries, is seeking opportunities in both domestic and international markets for engineering services and ownership of generating facilities. Although these opportunities are concentrated in areas that utilize the Company's expertise, they present different and greater risks than the Company's core business. The Company considers only opportunities in which the expected return is commensurate with the risk, and makes efforts to mitigate such risk. During 1992, Duke Energy Corp. led an international consortium that acquired majority ownership of the Guemes Power Station, a 245-megawatt natural gas-fueled plant in Argentina. A group led by Duke Engineering & Services, Inc. (DE&S) will operate the plant. Also during 1992, Duke/Fluor Daniel, a joint venture between DE&S and Fluor Daniel, Inc., began construction of South Carolina Electric & Gas Company's 385-megawatt plant to be located in Orangeburg County, South Carolina.

In February 1991, DE&S, as a part of a nine-member project team, signed a 10-year contract to perform systems engineering, development and management of the DOE's civilian radioactive waste management program.

EMPLOYEES

At December 31, 1992, the Company employed approximately 18,000 full-time persons, exclusive of approximately 750 full-time employees of subsidiaries. About 2,000 electrical operating employees are represented by the International Brotherhood of Electrical Workers with which the Company has a labor agreement expiring on October 1, 1993. The Company has been engaged in a concentrated effort to more efficiently and effectively utilize its resources through better work practices. The implementation of these practices has resulted in a reduction in workforce. The number of full-time employees has decreased by approximately 1,400 since December 31, 1990. This trend is expected to continue primarily through employee attrition.
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The Company is offering a separation opportunity to eligible employees in the first quarter of 1993, to encourage voluntary reduction of the workforce. Termination benefits associated with this program will be recognized in 1993.

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SUBSEQUENT EVENTS

REFINANCING PROGRAM

On February 12, 1993 the Company called for redemption $50,000,000 principal amount of it 8.28% Preferred Stock, Series K. To provide funds for such redemption, the Company issued 500,000 shares of 7% Preferred Stock, Series W.

On February 23, 1993 the Company called for redemption $175,000,000 principal amount of its 9% First and Refunding Mortgage Bonds Series Due 2016. To provide fund for such redemption, the Company has entered into an agreement to sell $200,000,000 principal amount of 7 3/8% First and Refunding Mortgage Bonds, Series Due 2023.

In addition, the Company called for redemption on February 25, 1993 $100,000,000 principal amount of its 7 7/8% First and Refunding Mortgage Bonds, Series Due 1996 and $78,100,000 principal amount of its 7 3/4% First and Refunding Mortgage Bonds, Series Due 2002. The Company sold $100,000,000 principal amount of 6 5/8% First and Refunding Mortgage Bonds, Series B Due 2003 and has entered into an agreement to sell $75,000,000 principal amount of 5 7/8% First and Refunding Mortgage Bonds, Series C Due 2003 to provide funds for such redemption.

On February 24, 1993 the Company also entered into an agreement to sell $125,000,000 principal amount of 6 3/8% First and Refunding Mortgage Bonds, Series Due 2008. The proceeds from these bonds will be used to refund existing bonds.

PROPOSED ENERGY TAX

On February 17, 1993 President Clinton announced that he would propose an increase in the corporate income tax rate and a new tax on energy based on the heat content of fuel as measured in British Thermal Units. Although the tax changes may be significant, the Company is not presently able to fully assess their potential impact.
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[MAP OMITTED: "Duke Power Service Area" LEGEND REGION OFFICE, STEAM ELECTRIC STATION, HYDROELECTRIC STATION, NUCLEAR ELECTRIC STATION, NANTAHALA POWER AND LIGHT"]

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DUKE POWER COMPANY
OPERATING STATISTICS
Year Ended December 31

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	1992	1991	1990
Sources of Electric Energy			
Millions of kilowatt-hours:			
Generated--net output:			
Coal	28,999	26,455	27,262
Nuclear (A)	48,238	49,328	44,649
Hydro	1,834	1,545	1,879
Oil and gas	5	7	53
Total generation	79,076	77,335	73,843
Purchased power and net interchange (B)	1,403	587	1,531
Total output	80,479	77,922	75,374
Less: Other Catawba Joint Owners' share	14,313	12,280	11,735
Plus; Purchases from Other Catawba Joint Owners	9,466	8,525	8,658
Total sources of energy	75,632	74,167	72,297
Line loss and company usage	(4,590)	(4,280)	(4,222)
Total energy sales (C)	71,042	69,887	68,075
Average Cost Per Ton of Coal Burned	$43.47	$45.21	$45.49
Electric Energy Sales			
Millions of Kilowatt-hours:			
Residential	17,789	17,918	17,221
General service	15,818	15,586	15,032
Industrial			
Textile	11,685	11,315	11,130
Other	15,356	14,955	14,764
Wholesale and other energy sales (B) (D)	10,360	10,132	10,468
Total energy sales billed	71,008	69,906	68,615
Unbilled energy sales	34	(19)	(540)
Total energy sales (C)	71,042	68,887	68,075
Electric Revenue			
Thousands of dollars:			
Residential	$1,312,227	$1,272,322	$1,216,945
General service	964,853	921,337	886,480
Industrial			
Textile	482,172	475,191	476,493
Other	696,413	668,765	654,551
Wholesale and other energy sales (B) (D)	460,849	441,777	391,803
Other electric revenues	44,970	37,568	78,859

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Total electric revenues (C)	$3,961,484	$3,816,960	$3,705,131
Number of Customers--End of Year			
Residential	1,439,845	1,415,605	1,391,336
General service (E)	227,675	222,917	224,642
Industrial			
Textile	1,390	1,385	1,398
Other	7,314	7,255	7,325
Wholesale and other energy sales (B)	7,773	7,605	7,405
Total customers	1,683,997	1,654,767	1,632,106
Residential Customer Statistics			
Average number for year	1,431,403	1,409,775	1,383,799
Average annual use--KWH	12,427	12,710	12,444
Average annual billing	$916.74	$902.50	$879.42
Average Annual Billed Revenue Per KWH			
Residential	7.38cents	7.10cents	7.07cents
General service	6.10cents	5.91cents	5.90cents
Industrial	4.36cents	4.35cents	4.37cents
Wholesale and other energy sales (B)	4.45cents	4.36cents	3.74

(TABLE CONTINUED)

	Year Ended December 31	
	1989	1988
Sources of Electric Energy		
Millions of kilowatt-hours:		
Generated--net output:		
Coal	26,175	23,930
Nuclear (A)	47,773	47,934
Hydro	1,520	402
Oil and gas	27	32
Total generation	75,495	72,298
Purchased power and net interchange (B)	1,158	1,385
Total output	76,653	73,683
Less: Other Catawba Joint Owners' share	12,566	12,166
Plus: Purchases from Other Catawba Joint Owners	9,809	10,244
Total sources of energy	73,896	71,761
Line loss and company usage	(4,522)	(4,449)

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Total energy sales (C)	69,374	67,312
Average Cost Per Ton of Coal		
Burned	$45.13	$44.27
Electric Energy Sales		
Millions of kilowatt-hours:		
Residential	16,895	16,744
General service	14,206	13,634
Industrial		
Textile	11,443	11,134
Other	14,491	14,020
Wholesale and other energy sales (B) (D)	11,969	11,615
Total energy sales billed	69,004	67,147
Unbilled energy sales	370	165
Total energy sales (C)	69,374	67,312
Electric Revenue		
Thousands of dollars:		
Residential	$1,198,705	$1,205,471
General service	851,422	833,709
Industrial		
Textile	493,933	495,100
Other	653,830	651,420
Wholesale and other energy sales (B) (D)	449,545	463,793
Other electric revenues	45,520	(5,083)
Total electric revenues (C)	$3,692,955	$3,644,410
Number of Customers--End of Year		
Residential	1,362,118	1,339,206
General service (E)	216,960	210,122
Industrial		
Textile	1,408	1,424
Other	7,310	7,232
Wholesale and other energy sales (B)	7,249	7,133
Total customers	1,595,045	1,565,117
Residential customer Statistics		
Average number for year	1,356,088	1,327,452
Average annual use--KWH	12,459	12,614
Average annual billing	$883.94	$908.11
Average Annual Billed Revenue Per KWH		
Residential	7.09cents	7.20cents
General service	5.99cents	6.11cents
Industrial	4.43cents	4.56cents

Wholesale and other energy sales (B)	3.76cents	3.99cents

(A) Includes 100% of Catawba generation.
(B) Purchased power and net interchange, kilowatt-hour sales, electric revenue, number of customers, and average annual billed revenue per KWH include a reclassification for certain power transactions previously classified as net interchange and purchased power per a 1990 FERC order.
(C) Does not reflect operating statistics, kilowatt-hour sales and revenues of Nantahala Power and Light Company.
(D) Includes sales to Nantahala Power and Light Company.
(E) 1991 restated to eliminate certain duplicate customers.

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EXECUTIVE OFFICERS OF THE COMPANY

Name	Position	Service In Such Capacity Since	Age(*)
William S. Lee(**)	Chairman of the Board and President (Chief Executive Officer)	1982	63
William H. Grigg(**)	Vice Chairman of the Board	1991	60
William A. Coley(**)	Executive Vice President, Customer Group	1991	49
Steve C. Griffith Jr.(**)	Executive Vice President and General Counsel	1991	59
Richard B. Priory(**)	Executive Vice President, Power Generation Group	1991	46
Richard J. Osborne(**)	Vice President and Chief Financial Officer	1991	41
David L. Hauser	Controller (Chief Accounting Officer)	1987	41

OTHER OFFICERS

Donald H. Denton, Jr	Senior Vice President, Planning and Operating
Hal B. Tucker	Senior Vice President, Nuclear Generation Department
James R. Bavis	Vice President, Human Resources
Sue A. Becht	Treasurer
Paul F. Briggs, Jr	Vice President, Winston-Salem Area
Lewis F. Camp, Jr.	Secretary and Associate General Council
Sharon A. Decker	Vice President, Customer Services
Excell O. Ferrell, III	Vice President, Northern Region
William L. Foust	President, Duke Merchandising

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Ronald L. Gibson Vice President, Customer Planning
James E. Grogan Vice President, Generation Services Department
James W. Hampton Vice President, Oconee Nuclear Site
Donald E. Hatley Vice President, Public Affairs
Jim R. Hicks Vice President, Information Technology Services
J. William Hillhouse, Jr. Vice President, Charlotte Area
James D. Hinton Vice President, Power Delivery
John P. Holland Vice Marketing, Marketing
F. Alfred Jenkins Vice President, Hickory Area
John P. Kincaid, Jr. Vice President, Greenville Area
John F. Lomax Vice President, Southern Region
David H. Maner Vice President, Greensboro Area
Maurice D. McIntosh Vice President, Fossil & Hydro Generation Department
Ted C. McMeekin Vice President, McGuire Nuclear Site
John P. O'Keefe Vice President, Taxes
William F. Reinke Vice President, System Planning & Operating
William T. Robertson, Jr. Vice President, Procurement, Services and Materials
Christopher C. Rolfe Vice President, Corporate Performance
Ruth G. Shaw Vice President, Corporate Communications
William R. Stimart Vice President, Rates and Regulatory Affairs
Michael S. Tuckman Vice President, Catawba Nuclear Site
Fred E. West, Jr. Vice President, Central Region
Virginia M. Britton Assistant Controller
Carolyn R. Duncan Assistant Secretary
S. L. Love Assistant Treasurer
Phyllis T. Simpson Assistant Secretary

(*) As of February 1, 1993.
(**) Member of the Management Committee.
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Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officer nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

All of the above executive officers have held responsible positions with the Company for the past five years.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the

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evaluation of the ability and integrity of any executive officer during the past five years.

ITEM 2. PROPERTIES.

The map on page 13 shows the location of the Company's service area and generating stations.

Reference is made to Schedule V--Property, Plant and Equipment for information concerning the Company's investment in utility plant. Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see "Business--Energy Management and Future Power Needs."

ITEM 3. LEGAL PROCEEDINGS.

Reference is made to "Business--Regulation--Nuclear Facilities" and 13 of "Notes to Consolidated Financial Statements".

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

No matters were submitted to a vote of the Company's security holders during the last quarter of 1992.

PART II.

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

The Common Stock of the Company is traded on the New York Stock Exchange. At December 31, 1992, there were approximately 125,881 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by the New York Stock Exchange Composite Transactions:

	Dividends	Price Range	
Common Stock	Per Share	High	Low

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1992 by Quarter			
Fourth	$0.45	$37 1/2	$34 5/8
Third	0.45	36 1/2	34 1/8
Second	0.43	34 5/8	32
First	0.43	35	31 3/8
1991 by Quarter			
Fourth	$0.43	$35	$30 1/8
Third	0.43	32 1/2	27 3/8
Second	0.41	29 3/8	27 1/4
First	0.41	30 3/4	26 3/4

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ITEM 6. SELECTED FINANCIAL DATA

	1992	1991	1990
Condensed consolidated statements of income (thousands)			
Electric revenues (a)	$ 3,961,484	$ 3,816,960	$ 3,705,131
Electric expenses (a)	3,236,789	3,110,137	3,062,348
Electric operating income	724,695	706,823	642,783
Other income	85,007	150,905	146,740
Income before interest deductions	809,702	857,728	789,523
Interest deductions	301,619	274,105	251,335
Cumulative effect of accrual of unbilled revenues	-	-	-
Net income	508,083	583,623	538,188
Dividends on preferred and preference stock	56,407	54,683	52,616
Earnings for common stock	$ 451,676	$ 528,940	$ 485,572
Common stock data (b)			
Shares of common stock--			
year-end (thousands)	204,859	204,699	202,584
--average (thousands)	204,819	203,431	202,570
Per share of common stock			
Earnings (c)	$2.21	$2.60	$2.40
Dividends	$1.76	$1.68	$1.60

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Book value--year-end	$20.26	$19.86	$18.84
Market price--high-low	$37 1/2-31 3/2	$ 35-26 3/4	$32 3/8-25 1/2
--year-end	$361/2	$35	$305/8

(TABLE CONTINUED)

	1989	1988
Condensed consolidated statements of income (thousands)		
Electric revenues (a)	$ 3,692,955	$ 3,644,410
Electric expenses (a)	2,988,355	3,014,859
Electric operating income	704,600	629,551
Other income	101,826	46,211
Income before interest deductions	806,426	675,762
Interest deductions	234,815	227,631
Cumulative effect of accrual of unbilled revenues	--	102,255
Net income	571,611	550,386
Dividends on preferred and preference stock	52,477	53,329
Earnings for common stock	$ 519,134	$ 497,057
Common stock data (b)		
Shares of common stock--		
year-end (thousands)	202,563	202,544
--average (thousands)	202,554	202,533
Per share of common stock		
Earnings (c)	$2.56	$2.45
Dividends	$1.52	$1.44
Book value--year-end	$18.05	$17.01
Market price--high-low	$28 1/4-21 3/8	$24 1/2-21 1/8
--year-end	$28 1/16	$23 1/8

(a) Electric revenues, electric expenses, kilowatt-hour sales and Net interchange and purchased power for the years 1988 through 1990 include a reclassification for certain power transactions previously classified as Net interchange and purchased power prior to a 1990 FERC order.
(b) All common stock data reflects the two-for-one split of common stock on September 28, 1990.
(c) Includes cumulative effect of the accounting change for unbilled revenues for 1988.

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[HARDCOPY PAGE 18]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

RESULTS OF OPERATIONS

EARNINGS AND DIVIDENDS

Earnings per share decreased 15 percent, from $2.60 in 1991 to $2.21 in 1992. Earnings per share also decreased from $2.40 in 1990 to $2.21 in 1992. The decrease was primarily due to a onetime impact of $ .32 per share related to a refund to North Carolina retail customers in 1992. This refund is the result of an order by the North Carolina Utilities Commission (NCUC), which retroactively lowered the Company's authorized rate of return on common equity for the period October 31, 1986 through November 11, 1991, in response to a decision of the North Carolina Supreme Court. (For additional information on the refund, see Liquidity and Resources "Rate Matters," below.) Kilowatt-hour sales increased in 1992 compared with 1991 and 1990; however, operating and maintenance expenses also increased. The Company's total earned return on average common equity was 11.1 percent in 1992 and 13.5 percent in 1991 and 13.1 percent in 1990.

The Company continued its practice of increasing the common stock dividend annually. Common dividends per share increased from $1.60 in 1990 to $1.76 in 1992, rising at an average annual rate of 5 percent. Indicated annual dividends per share increased to $1.80

REVENUE AND SALES

Revenues increased at an average annual rate of 3 percent from 1990 to 1992, primarily because of increased kilowatt-hour sales, principally to industrial and general service customers, and the November 1991 rate increase.

Kilowatt-hour sales for 1992 increased 2 percent compared to 1991. Sales billed to industrial customers increased 3 percent, reflecting continued economic recovery in the Company's service territory. Special sales billed to other utilities increased 2 percent and sales to general service customers increased 1 percent, while sales to residential customers decreased slightly because of cooler summer weather.

OPERATING EXPENSES

Non-fuel operating and maintenance expenses rose at an average annual rate of 4 percent from 1990 to 1992. Higher fees paid to the Nuclear Regulatory Commission contributed to the increase. These expenses were

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also increased by the implementation of a new accounting standard in 1992 requiring accrual basis accounting for certain postretirement health care and life insurance benefits, which are being recovered through rates.

Non-fuel operating and maintenance expenses increased 6 percent from 1991 to 1992. Higher operating and maintenance expenses for both fossil and nuclear stations and implementation of the new accounting standard in 1992 referred to above were the primary reasons for the increase.

From 1990 to 1992, Net interchange and purchased power decreased at an average annual rate of 2 percent. The decline was primarily due to an extension of the period that the Company recovers, on a levelized basis, capital and fixed operating and maintenance costs of capacity purchased from the other Catawba joint owners. This extension was effective with the Company's 1991 rate orders. (For additional information on the levelization, see Note 3 to the Consolidated Financial Statements.)

Fuel expense remained stable from 1990 to 1992. Higher production requirements, met largely through an increase in fossil generation, were offset by continued declining fuel prices.

From 1991 to 1992, Depreciation and amortization expense increased 14 percent primarily because of completion of the Bad Creek Hydroelectric Station, which is being recovered through rates set in 1991. Increased investment in distribution and fossil property was also a contributing factor. Depreciation and amortization expense increased at an average annual rate of 10 percent from 1990 to 1992.

OTHER INCOME AND INTEREST DEDUCTIONS

Allowance for funds used during construction (AFUDC) represented 5 percent of earnings for common stock in 1992, decreasing from 13 percent in 1991 and from 23 percent in 1990. The decrease in AFUDC in 1992 compared to 1991 and 1990 is a result of the completion of the Bad Creek Hydroelectric Station. AFUDC will gradually increase as construction of the Lincoln Combustion Turbine Station begins; however, AFUDC is expected to represent less than 10 percent of earnings in each of the next three years. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs "Meeting Future Power Needs," page 20.)

The net of tax carrying charge on purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station represented 6 percent of total earnings in 1992, compared to 5 percent in 1991 and 1990. This carrying charge and the related tax benefits are included in Other, net and Income taxes-other, net, respectively. The growth in this carrying charge is due to the increasing cumulative

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impact of the Company's funding of purchased power costs not currently collected in rates. As currently provided in rates in all jurisdictions, the Company recovers the costs of purchased energy and a portion of purchased capacity. The portion of costs not currently recovered through rates is being accumulated, and the Company is recording a carrying charge on the accumulated balance. The Company recovers the accumulated balance, including the carrying charge, when the declining purchased capacity payments drop below the levelized revenues. (For additional information on purchased capacity levelization, see Capital Needs "Purchased Capacity Levelization," page 20.)

The Company continues to pursue diversified activities through its subsidiaries and non-utility operations. The overall contribution of these operations to the Company's earnings was $29.9 million in 1992 compared to $26.9 million in 1991 and $26.2 million in 1990. The major sources of subsidiary and non-utility earnings are the activities of Crescent Resources, Inc., the Company's land management and real estate development subsidiary, and investment income.

Interest on long-term debt decreased 3 percent from 1991 to 1992. The decrease is due to the Company's refinancing of higher cost debt in late 1991 and during 1992. From 1990 to 1992, Interest on long-term debt increased at an average annual rate of 1 percent due to additional issuances of long-term debt in 1991 and 1992. Total interest deductions in 1992 have increased in comparison to 1991 and 1990, because of the one-time impact of approximately $27 million in interest paid to North Carolina retail customers as the result of a rate refund. (For additional information on the refund, see Liquidity and Resources "Rate Matters," below.)

LIQUIDITY AND RESOURCES

RATE MATTERS

During 1991, the Company filed in both the North Carolina and the South Carolina retail jurisdictions its first requests for rate

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increases since 1986. The rate increase requested by the Company in North Carolina was 9.22 percent; a4.15 percent increase was granted resulting in $100.1 million in additional annual revenues. In South Carolina, a rate increase of 7.29 percent was requested, a 3.0 percent increase was granted resulting in $30.2 million in additional annual revenues. These increases were requested primarily to recover costs associated with the Bad Creek Hydroelectric Station.

In 1991, the Company filed a request with the Federal Energy Regulatory

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Commission (FERC) seeking a 7.47 percent rate increase for its wholesale customers, who represent approximately 2 percent of the Company's total revenues. The wholesale customers challenged the Company's rate requests, and on January 30, 1992, a settlement agreement between Duke and its wholesale customers was filed with the FERC. The agreement provided for $2.1 million in additional annual revenues, a 3.3 percent increase, to become effective April 1, 1992. On March 31, 1992, the FERC approved the settlement agreement.

The North Carolina Supreme Court on April 22, 1992, remanded for the second time the Company's 1986 rate order to the NCUC. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return of 13.2 percent on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued an order dated October 26, 1992, authorizing a 12.8 percent return on common equity for the period October 31, 1986 through November 11, 1991, that resulted in a refund to North Carolina retail customers in 1992 of approximately $95 million, including interest.

The other joint owners of the Catawba Nuclear Station and the Company are involved in various proceedings related to the Catawba joint ownership agreements. The basic contention in each proceeding is that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other joint owners which have been approved by the Company's retail regulatory commissions (see Note 3 to the Consolidated Financial Statements). Although the other joint owners have not fully quantified the dollars associated with the presently outstanding proceedings, information associated with these proceedings indicates that the amount in contention could be as high as $360 million through December 31, 1992. Arbitration hearings were held in 1992 involving substantially all of the disputed amounts. The ultimate resolution of these matters cannot presently be determined; however, the Company is of the opinion that it has properly interpreted these agreements and that these costs would be included and recovered as part of the purchased capacity levelization consistent with prior orders of the retail regulatory commissions. (For additional information, see Capital Needs "Purchased Capacity Levelization," page 20.) Therefore, the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

CASH FROM OPERATIONS

In 1992, net cash provided by operating activities accounted for 50 percent of total cash from operating, financing and investing activities compared to 77 percent in 1991. The Company's cash requirement for the refinancings of long-term debt and preferred stock in 1992 is the primary factor causing the decrease in this percentage.

CAPITAL STRUCTURE

The Company's capital structure at year-end 1992 was 51 percent common equity, 39 percent long-term debt, and 10 percent preferred stock, which is consistent with the Company's target. The target is set in order to maintain "doubt A" credit rating.

FINANCING AND INVESTING ACTIVITIES

During 1990, the Company issued $390 million in long-term debt, part of which was used to redeem $103 million of long-term debt. The Company also issued $75 million of preferred stock. During 1991, the Company issued $425 million in long-term debt, part of which was used to refund $270 million of long-term debt.

In 1992, the Company obtained proceeds from the issuance of $940 million in First and Refunding Mortgage Bonds. Most of these proceeds, combined with the proceeds from bonds issued in late 1991, were used to redeem $884 million of long-term debt. The Company also issued $284 million of preferred stock, most of which was used to reedem $229 million of preferred stock. As of December 31, 1992, the Company's bonds were rated "doubt A" by Moody's Investors Service and Fitch Investors Service and "double A minus" by Standard & Poor's Corp. and Duff & Phelps.

During 1993, the Company anticipates issuing an additional $100 million in long-term debt, net of any refinancing activity.

On April 6, 1992, the Company redeemed all outstanding shares of the Cumulative Preference Stock, 6 3/4% Convertible Series AA at its par value of $100 per share.

Effective April 1, 1991, the Company began issuing common stock in lieu of purchasing shares on the open market for its various stock purchase plans. Smaller than anticipated capital expenditures eliminated the need for additional equity financings and the Company discontinued issuances of common stock, effective December 1, 1991, and resumed open market purchase to satisfy the requirements of the various stock purchase plans.

During 1990, the Board of Directors declared a two-for-one split of

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Duke Power common stock. The Company issued common stock to satisfy the requirements for the stock split and for the conversion rights of preference stock.

The Company's embedded cost of long-term debt of 1992 decreased to 8.39 percent compared to 8.72 percent for 1991. The decrease was primarily due to the Company's debt refinancings during 1992. From 1990 to 1991, the Company's embedded cost of long-term debt decreased from 8.78 percent to 8.72 percent. The embedded cost of preferred stock declined to 7.05 percent for 1992 compared to 7.48 percent in 1991, primarily because of preferred stock refinancings during 1992. From 1990 to 1991, the embedded cost of preferred stock decreased from 7.74 percent to 7.48 percent.

As of December 31, 1992, the Company had approximately $32 million in intermediate-term investments and $141 million in short--term investments.

FIXED CHARGES COVERAGE

Fixed charges coverage decreased to 3.48 times for 1992 compared to 3.85 times in 1991 using the SEC method. The earnings impact of the rate refund to North Carolina retail customers was the primary cause of the decrease. Fixed charges coverage, excluding AFUDC and return on purchased capacity levelization,
[HARDCOPY PAGE 20]

was 3.27 times in 1992 compared to 3.46 in 1991 and to the Company's goal of 3.5 times. This decrease was also largely a result of the refund to North Carolina retail customers. (For additional information on the refund, see Liquidity and Resources "Rate Matters," page 18.)

CAPITAL NEEDS

PROPERTY ADDITIONS AND RETIREMENTS

Additions to property and nuclear fuel of $689 million and retirements of $81 million resulted in an increase in gross plant of $608 million in 1992.

Since January 1, 1990, additions to property and nuclear fuel of $2.5 billion and retirements of $283 million have resulted in an increase in gross plant of $2.3 billion.

CONSTRUCTION EXPENDITURES

Plant construction costs for generating facilities, including AFUDC, decreased from $438 million in 1990 to $145 million in 1992. The decrease in plant construction costs from 1990 to 1992 was primarily

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due to the completion of the Bad Creek Hydroelectric Station in 1991. Construction costs for distribution plant, including AFUDC, decreased from $330 million in 1990 to $224 million in 1992, reflecting the result of streamlined business practices and slower customer growth.

PURCHASED CAPACITY LEVELIZATION

The rates established in the Company's retail jurisdictions permit the Company to recover its investment in both units of the Catawba Nuclear Station and the costs associated with contractual purchases of capacity from the other Catawba joint owners. The contracts relating to the sales of portions of the station obligate the Company to purchase power from the other joint owners on an annually declining basis. In the North Carolina retail jurisdiction, regulatory treatment of these contracts provides revenue for the recovery of the capital costs and the fixed operating and maintenance costs of purchased capacity on a levelized basis. In the South Carolina retail jurisdiction, revenues are provided for the recovery of the capital costs of purchased capacity on a levelized basis, while current rates include recovery of fixed operating and maintenance expenses.

These rate treatments require the Company to fund portions of the purchased power payments until these costs, including carrying charges are recovered at a later date. The Company recovers the accumulated cost and carrying charges when the declining purchased capacity payments drop below the levelized revenues.

The levelized recovery of purchased power obligations under contracts with the other joint owners of the Catawba Nuclear Station is expected to result in amounts collected in rates in excess of payments by the Company for such power by approximately $211 million over the next three years, assuming that contingencies discussed in the Rate Matters section in "Liquidity and Resources," page 18, are resolved in the Company's favor. (For additional information with respect to purchased capacity levelization, see Note 3 to the Consolidated Financial Statements.)

[GRAPH OMITTED: "CONSTRUCTION COST MILLION OF DOLLARS NUCLEAR FUEL INCLUDING AFUDC."]

MEETING FUTURE POWER NEEDS

The Company's strategy for meeting customer's present and future energy needs is comprised of three components: supply-side options, demand-side options and purchased-power options.

Projected construction and nuclear fuel costs, both including AFUDC, are $2.4 billion and $427 million, respectively, for the period 1993 through 1995. Projected construction costs include the costs of supply-side options discussed below.

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The construction of a combustion turbine facility is scheduled to begin in spring 1993 in Lincoln County, North Carolina. The Lincoln Combustion Turbine Station will be able to accommodate 16 combustion turbines with a total generating capacity of 1,184 megawatts. The estimated total cost of the project is approximately $500 million. Current plans are for the first four units to begin commercial operation in 1995 and the remaining twelve by the end of 1996. The Lincoln facility will provide capacity at periods of peak demand.

Demand-side management programs are an integral part of meeting the Company's future power needs. These programs benefit the Company and its customers by providing for load control through interruptible control features and by promoting energy efficiency. In return for participation in demand-side management programs, the Company's customers may be eligible to receive various incentives which help to reduce their electric bills. Demand-side management programs such as Industrial Interruptible Service and Residential Load Control will be used to control the rate of growth in peak demand. Energy efficiency programs relating to commercial and industrial lighting and motors, high efficiency heat pumps and high efficiency air conditioners are other examples of current demand-side management programs. The November 1991 rate orders of the NCUC and The Public Service Commission of South Carolina (PSCSC) provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The costs deferred including the return, were approximately $18 million in 1992.

The purchase of capacity and energy is also an integral part of meeting future power needs. The Company currently has under contract 500 megawatts of capacity from other generators of electricity.

CURRENT ISSUES

While results of operations declined for the year primarily because of a rate refund, the Company continued to maintain a solid financial position in 1992. The ability to maintain and improve its current level of earnings will depend to a large degree on the continued economic recovery of industry in the Piedmont Carolinas, on the ability of the Company to control costs, on the outcome of various legislative and regulatory actions and on the success of diversified activities.

The Company has been engaged in a concentrated effort to

FIXED CHARGES COVERAGE TIMES

1987 1988 1989 1990 1991 1992

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4 4.24 3.88(*) 3.83 3.15 3.46 3.27
5 4.49 4.25 4.26 3.66 3.85 3.48
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more efficiently and effectively use its resources through better work practices. Implementing these practices has resulted in a continued reduction in workforce. The number of full-time employees (excluding subsidiaries and affiliates) has decreased from 19,449 at year-end 1990 to 17,968 at year-end 1992. The Company is offering a separation opportunity to eligible employees in the first quarter of 1993, to encourage voluntary reduction of the workforce. Termination benefits associated with its program will be recognized in 1993.

In January 1992, the Company implemented a standard as required by the Financial Accounting Standards Board (FASB) that involves accounting for certain health care and life insurance benefits for retired employees (postretirement benefits) as earned rather than on a current cash (pay-as-you-go) basis. The transition obligation of approximately $250 million that resulted from implementing this standard is being amortized over twenty years. The transition obligation and the annual cost of providing postretirement benefits are reflected in current electric rates established in 1991 by the NCUC and the PSCSC. Benefit plans are subject to future change, modification or termination by the Company. (For additional information with respect to postretirement benefits, see Note 12 to the Consolidated Financial Statements.)
In 1993, the FASB will require a change in the method of accounting for income taxes. The FASB statement requires a liability approach for financial accounting and reporting for income taxes. While classification of certain items on the Consolidated Balance Sheets will change, principally due to certain items previously reported net of tax being reported on a gross basis, there will be no material effect on the Company's results of operations.

The Nuclear Regulatory Commission (NRC) issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission the components of a nuclear unit subject to radioactive contamination. The estimated site-specific obligations for decommissioning cost, including cost for plant components not subject to radioactive contamination, total approximately $955 million stated in 1990 dollars. This amount includes the Company's ownership percentage of 12.5 percent in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are liable for providing for decommissioning related to their ownership interest in the station. During 1992, the Company funded approximately $61 million to satisfy the NRC requirements. Effective with the implementation of new retail rates in 1991, the NCUC and the PSCSC granted the Company recovery of the estimated site-specific decommissioning costs through retail rates. It is management's opinion that the estimated site-specific

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decommissioning cost being recovered through rates are currently sufficient to provide for the cost of decommissioning, assuming the Company's nuclear plants are not decommissioned prior to the end of their licensed life.

The Company is subject to federal, state and local regulations with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. The Company is subject to contingencies associated with environmental matters, principally related to possible obligations to remove or mitigate the effects on the environment of the disposal of certain substances at various sites. The Company is currently participating in environmental assessments and cleanups under these laws at two federal Superfund and several comparable state sites. While the total cost of remediation at these sites may be substantial, the Company shares probable liability with other potentially responsible parties. The Company has also been involved in several manufactured gas plant sites where site assessments are currently being performed or are planned in order to determine where remediation may be appropriate. Based on the information known to the Company at this time, management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

The Clean Air Act Amendments of 1990 require a two phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national objective of clean air and has already reduced emissions through the use of low-sulfur coal in its fossil plants, through efficient operations and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. The Company is considering all of the alternatives to devise an optimum strategy for compliance with more stringent Phase II requirements at the least cost. A preliminary strategy, which is currently being reviewed, indicates an estimated cost of approximately $1 billion in capital and $81 million in annual operating and maintenance costs (in year 2000 dollars) for compliance with Phase II requirements and other provisions of the Act. The Company is currently working on a detailed compliance plan that must be filed and approved by the Environmental Protection Agency by 1996.

Stress corrosion cracking (SCC) has occurred in steam generators of a certain design, including those at the McGuire and Catawba Nuclear Stations. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC will be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the Catawba and McGuire steam generators still exists. The Company

has begun planning for the replacement of steam generators and has set the following schedule: McGuire Unit1 - 1995; Catawba Unit 1 - 1996; McGuire Unit 2 - 1997. The Catawba Unit 2 steam generators have not been scheduled for replacement. The order of replacement is subject to change based on performance of the existing steam generators and on the overall performance of the three units. The Company has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $200 million, excluding the cost of replacement power and without consideration of reimbursement of applicable costs by the other joint owners of Catawba Unit 1. Stress corrosion problems are excluded under the nuclear insurance policies.

The Company in connection with its McGuire and Catawba Stations and on behalf of the other joint owners of the Catawba Station - North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation, Piedmont Municipal Power Agency and Saluda River Electric Cooperative, Inc.-commenced an action on March 22, 1990, that alleges Westinghouse Electric Corporation (Westinghouse), the supplier of the steam generators, knew, or recklessly disregarded information in its possession, that the steam generators supplied to the McGuire and Catawba Stations would be susceptible to SCC and that Westinghouse deliberately concealed such information from the Company. The Company is seeking a judgement against Westinghouse for damages including the cost of replacement steam generators, payment for replacement power during the outages to accomplish steam generator replacement and for punitive damages related to the fact that Westinghouse concealed this

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information.

The Company reached a bulk power sale agreement in 1987 to provide Carolina Power & Light Company (CP&L) 400 megawatts of electricity for a six-year period beginning in 1992. The agreement was filed with the FERC in 1989. The Company and CP&L subsequently disagreed on whether the agreement was binding. The Company and CP&L have settled the dispute and amended the agreement to reflect that settlement, which provides for implementing the six-year contract period beginning in July 1993. The Company plans to return earnings from the sale, through rates, to the Company's retail customers.

The Energy Policy Act of 1992 has far-reaching implications for the Company by moving utilities toward a more competitive environment. Reform of the Public Utility Holding Company Act of 1935 (PUHCA) will remove barriers to the Company, allowing it to develop independent electric generating plants in the United States for sales to wholesale customers as well as contract for utility projects internationally,

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without becoming subject to registration under PUHCA as an electric utility holding company. The Act requires transmission for third parties to wholesale customers, provided the reliability of service to the utility's local customer base is protected and the local customer base does not subsidize the third party service. The Company presently believes this legislation will lead to no appreciable erosion in its customer base because its rates are regionally and nationally competitive.

The Company, through its subsidiaries, is seeking opportunities both domestic and international markets for engineering services and ownership of generating facilities. Although these opportunities are concentrated in areas that utilize the Company's expertise, they present different and greater risks than the Company's core business. The Company considers only opportunities in which the expected return is commensurate with the risk, and makes efforts to mitigate such risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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CONSOLIDATED STATEMENTS OF INCOME

Dollars in Thousands Year ended December 31,	1992	1991	1990
Electric revenues (Notes 1, 2 and 15)	$3,961,484	$3,816,960	$3,705,131
Electric expenses			
Operation			
Fuel used in electric generation (Note 1)	659,593	657,725	660,298
Net interchange and purchased power (Notes 3 and 15)	540,840	545,840	565,034
Wages, benefits and materials	636,729	622,121	564,624
Maintenance of plant facilities	403,162	354,679	403,831
Depreciation and amortization (Notes 1 and 11)	491,339	431,624	405,762
General taxes	215,493	204,688	197,087
Income taxes (Notes 1 and 4)	289,633	293,460	265,712
Total electric expenses	3,236,789	3,110,137	3,062,348
Electric operating income	724,695	706,823	642,783
Other income (Notes 1, 4 and 14)			
Allowance for equity funds used during construction	15,476	50,704	79,176
Other, net	83,216	102,884	54,210
Income taxes-other, net	(27,475)	(25,472)	(15,284)
Income taxes-credit	13,790	22,789	28,638
Total other income	85,007	150,905	146,740
Income before interest deductions	809,702	857,728	789,523
Interest deductions			
Interest on long-term debt	265,646	274,662	260,333
Other interest	41,736	18,834	21,296
Allowance for			

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borrowed funds used during construction (credit)(Note 1)	(5,763)	(19,391)	(30,294)
Total interest deductions	301,619	274,105	251,335
Net income	508,083	583,623	538,188
Dividends on preferred and preference stock	56,407	54,683	52,616
Earnings for common stock	$ 451,676	$ 528,940	$ 485,572
Common stock data (Note 6)			
Average shares outstanding (thousands)	204,819	203,431	202,570
Earnings per share	$2.21	$2.60	$2.40
Dividends per share	$1.76	$1.68	$1.60

See Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Dollars in Thousands Year ended December 31,	1992	1991	1990
Cash flows from operating activities			
Net income	$508,083	$ 583,623	$ 538,188
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash items			
Depreciation and amortization (Notes 1 and 11)	660,896	619,823	576,268
Deferred income taxes and investment tax credit, net of amortization (Note 4)	44,518	27,456	31,850
Allowance for equity funds used during			

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construction	(15,476)	(50,704)	(79,176)
Purchased capacity levelization (Note 3)	(66,511)	(70,605)	(93,853)
Other, net	(25,327)	(32,149)	(19,194)
(Increase) Decrease in			
Accounts receivable	14,255	(45,412)	56,353
Materials and supplies	(9,383)	6,866	(28,535)
Prepayments	(939)	181	356
Increase (Decrease) in			
Accounts payable	69,739	44,265	(5,181)
Taxes accrued (Notes 1 and 4)	4,514	11,739	(42,034)
Interest accrued and other liabilities (Notes 1 and 9)	(22,825)	12,863	31,728
Total adjustments	653,461	524,323	428,582
Net cash provided by operating activities	1,161,544	1,107,946	966,770
Cash flows from investing activities			
Construction expenditures	(465,292)	(572,705)	(836,474)
Investment in nuclear fuel	(122,565)	(183,803)	(136,528)
Funding for decommissioning	(61,246)	-	-
Net change in investment securities (Note 1)	(77,910)	(35,807)	23,952
Net cash used in investing activities	(727,013)	(792,315)	(949,050)
Cash flows from financing activities			
Proceeds from the issuance of			
First and refunding mortgage bonds	926,650	414,297	385,293
Preferred stock	281,089	-	73,875
Pollution-control trust	-	-	1,187
Short-term notes payable, net (Note 5)	40,000	(99,000)	15,000
Common stock	-	48,014	-
Payments for the redemption of			
First and refunding mortgage bonds	(1,013,218)	(279,970)	(108,893)
Preferred stock	(246,414)	(9,650)	(8,025)
Payments under capital lease obligation	(6,183)	(5,662)	(5,185)
Dividends paid	(417,443)	(381,589)	(376,720)

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Net cash used in financing activities	(435,519)	(313,560)	(23,468)
Net increase (decrease) in cash	(988)	2,071	(5,748)
Cash at beginning of year	10,281	8,210	13,958
Cash at end of year	$ 9,293	$ 10,281	$ 8,210

See Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS
Assets

Dollars in Thousands December 31,	1992	1991
Electric plant (at original cost -- Notes 1, 3, 9 and 13)		
Electric plant in service	$12,193,888	$11,830,211
Less accumulated depreciation and amortization	4,197,505	3,915,761
Electric plant in service, net	7,996,383	7,914,450
Nuclear fuel	2,268,947	2,004,441
Less accumulated amortization	1,873,830	1,722,192
Nuclear fuel, net	395,117	282,249
Construction work in progress (including nuclear fuel in process: 1992 - $148,945; 1991 - $183,812)	490,408	501,942
Total electric plant, net	8,881,908	8,698,641
Other property and investments		
Other property--at cost (less accumulated depreciation: 1992 $83,108; 1991 - $77,261)	239,585	187,788
Other investments, at cost or less (Note 10)	127,632	99,005
Total other property and investment	367,217	286,793
Current assets		

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Cash (Notes 5 and 10)	9,293	10,281
Short-term investments (Note 10)	141,285	92,003
Receivables (less allowance for losses: 1992-$5,207 1991-$4,988)(Note 1)	494,644	508,898
Materials and supplies -- at average cost		
Coal	101,550	96,361
Other	196,489	192,295
Prepayments	11,610	10,672
Total current assets	954,871	910,510
Deferred debits		
Purchased capacity costs (Note 3)	378,095	337,699
Canceled construction projects (Note 11)	28,889	68,302
Debt expense (Note 1)	115,436	86,018
Other	75,378	83,652
Total deferred debits	597,798	574,671
Total assets	$10,801,794	$10,470,615
Capitalization and Liabilities		
Capitalization (See Consolidated Statements of Capitalization)	$ 8,132,583	$ 7,956,498
Current liabilities		
Accounts payable	394,721	336,488
Taxes accrued (Note 1)	36,885	46,318
Interest accrued	68,078	73,410
Other	75,613	93,668
Total	575,297	549,884 s payable (Notes 5 and 10) 126,000 86,000
Current maturities of long-term debt and preferred stock	8,327	115,777
Total current liabilities	709,624	751,661
Accumulated deferred income taxes (Notes 1 and 4)	1,369,677	1,293,594
Deferred credits and other liabilities		
Investment tax credit (Notes 1 and 4)	296,165	307,743
Department of Energy assessment fee (Note 1)	101,785	-
Other	191,960	161,119
Total deferred credits and other liabilities	589,910	468,862
Commitments and contingencies (Note 13)		

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Total capitalization and Liabilities	$10,801,794	$10,470,615

See Notes to Consolidated Financial Statements

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CONSOLIDATED STATEMENTS OF CAPITALIZATION AND RETAINED EARNINGS

Dollars in Thousands December 31,	1992	1991
Capitalization		
Common stock equity (Notes 6 and 7)		
Common stock, no par, 300,000,000 shares authorized; 204,859,339 shares outstanding for 1992 and 204,699,851 shares outstanding for 1991	$1,926,909	$1,924,998
Retained earnings	2,223,718	2,141,259
Total common stock equity	4,150,627	4,066,257
Preferred and preference stock without sinking fund requirements (Note 7)	500,000	502,016
Preferred stock with sinking fund requirements (Notes 8 and 10)	279,519	228,650
Long-term debt (Notes 9 and 10)		
First and refunding mortgage bonds	3,061,422	3,105,042
Capitalized leases	53,782	59,966
Other long-term debt	130,000	130,000
Unamortized debt discount and premium, net (Note 1)	(35,940)	(29,181)
Current maturities of long-term debt	(6,827)	(106,252)
Total long-term debt	3,202,437	3,159,575
Total capitalization	$8,132,583	$7,956,498

Dollars in Thousands	Year ended December 31,	1992	1991	1990

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Retained Earnings			
Balance - Beginning of year	$ 2,141,259	$ 1,953,779	$ 1,793,829
Add - Net income	508,083	583,623	538,188
Total	2,649,342	2,537,402	2,332,017
Deduct			
Dividends			
Common stock	360,475	341,801	342,104
Preferred and preference stock	56,407	54,683	52,616
Capital stock transactions, net	8,742	(341)	1,518
Total deductions	425,624	396,143	378,238
Balance - End of year	$ 2,223,718	$2,141,259	$1,953,779

See Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. REVENUES

Revenues are recorded as service is rendered to customers. "Receivables" on the Consolidated Balance Sheets include $167,610,000 and $165,629,000 as of December 31, 1992 and 1991, respectively, for service that has been rendered but not yet billed to customers.

B. ADDITIONS TO ELECTRIC PLANT

The Company capitalizes all construction-related direct labor and materials as well as indirect construction cost. Indirect costs include general engineering, taxes and the cost of money (allowance for funds used during construction). The cost of renewals and betterments of units of property is capitalized. The cost of repairs and replacements representing less than a unit of property is charged to electric expenses. The original cost of property retired, together with removal costs less salvage value, is charged to accumulated depreciation.

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C. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

AFUDC represents the estimated debt and equity cost of capital funds that are necessary to finance the construction of new facilities. AFUDC, a non-cash item, is recognized as a cost of "Construction work in progress" (CWIP), with offsetting credits to "Other income" and "Interest deductions." After construction is completed, the Company is permitted to recover these capital costs, including a fair return, through their inclusion in rate base and in the provision for depreciation.

AFUDC, which is compounded semiannually, was calculated on average embedded rates (net of applicable income taxes) of 8.07 percent for 1992, 8.86 percent for 1991 and 9.13 percent for 1990.

D. DEPRECIATION AND AMORTIZATION

Provisions for depreciation are recorded using the straight-line method. The year-end composite weighted-average depreciation rates were 3.48 percent for 1992 and 1991 and 3.57 percent for 1990. Effective with the implementation of new retail rates in November 1991, all coal-fired generating units are depreciated at a rate of 2.57 percent and all nuclear units are depreciated at a rate of 4.70 percent, of which 1.61 percent is for decommissioning.

Amortization of nuclear fuel is included in "Fuel used in electric generation" in the Consolidated Statements of Income. The amortization is recorded using the unit-of-production method.

Under provisions of the Nuclear Waste Policy Act of 1982, the Company has entered into contracts with the Department of Energy (DOE) for the disposal of spent nuclear fuel. Payments made to the DOE for disposal costs are based on nuclear output and are included in "Fuel used in electric generation" in the Consolidated Statements of Income.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees will be subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The Company has reflected the present value of this obligation of approximately $102 million in the 1992 Consolidated Balance Sheets.

E. SUBSIDIARIES

The Company's consolidated financial statements reflect consolidation of all of its wholly-owned subsidiaries. All significant inter-company transactions have been eliminated in consolidation. (See "Subsidiary Highlights," page 38.)

F. INCOME TAXES

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The Company and its subsidiaries file a consolidated federal income tax return. Income taxes have been allocated to each company based on its separate company taxable income or loss.

Income taxes are allocated to non-electric operations under "Other income" and to electric operating expense. The "Income taxes-credit" classified under "Other income" results from tax deductions of interest costs relating primarily to investments in CWIP and canceled construction projects.

Deferred income taxes have been provided for timing differences between book and tax income, principally resulting from accelerated tax depreciation, canceled construction projects and levelization of purchased power costs. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

G. UNAMORTIZED DEBT PREMIUM, DISCOUNT AND EXPENSE

Expenses incurred in connection with the issuance of presently outstanding long-term debt, and premiums and discounts relating to such debt, are being amortized over the terms of the respective issues. Also, any expenses or call premiums associated with refinancing higher-cost debt obligations are being amortized over the lives of the new issues of long-term debt.
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H. FUEL COST ADJUSTMENT PROCEDURES

Fuel cost are received semiannually in the wholesale and South Corolina retail jurisdictions, with provisions for changing such costs in base rates. In the North Corolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings.

All jurisdictions allow the Company to adjust rates for past over-or under-recovery of fuel costs. Therefore, the Company reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

The North Carolina legislature ratified a bill in July 1987 assuring the legality of such adjustments in rates. In 1991, the staute was extended through June 30, 1997.

I. CONSOLIDATED STATEMENTS OF CASH FLOWS

For purposes of the Consolidated Statements of Cash Flows, the Company's investments in highly liquid debt instruments, with an

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original maturity of three months or less, are included in cash flows from investing activities and thus are not considered cash equivalents. Total income taxes paid were $215,465,000 in 1992, $245,945,000 in 1991 and $194,339,000 in 1990.

Interest paid, net of amount capitalized, was $298,455,000, $269,330,000 and $240,451,000 for the years ended December 31, 1992, 1991 and 1990, respectively.

NOTE 2. RATE MATTERS

The North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSCSC) must approve rates for retail sales within their respective states. The Federal Energy Regulatory Commission (FERC) must approve the Company's rates for sales to wholesale customers. Sales to the other joint owners of the Catawba Nuclear Station, which represent a substantial majority of the Company's wholesale revenues, are set through contractual agreements. (See Note 3.)
During 1991, the Company filed in both the North Carolina and the South Carolina retail jurisdictions its first requests for rate increases since 1986. The rate increase requested by the Company in North Carolina was 9.22 percent; a 4.15 percent increase was granted resulting in $100.1 million in additional annual revenues. In South Carolina, a rate increase of 7.29 percent was requested; a 3.0 percent increase was granted resulting in $30.2 million in additional annual revenues. These increases were requested primarily to recover costs associated with the Bad Creek Hydroelectric Station.

In 1991, the Company filed a request with the FERC seeking a 7.47 percent rate increase for its wholesale customers, who represent approximately 2 percent of the Company's total revenues. The wholesale customers challenged the Company's rate requests, and on January 30, 1992, a settlement agreement between Duke and its wholesale customers was filed with the FERC. The agreement provided for $2.1 million in additional annual revenues, a 3.3 percent increase, to become effective April 1, 1992. On March 31, 1992, the FERC approved the settlement agreement.

The North Carolina Supreme Court on April 22, 1992, remanded for the second time the Company's 1986 rate order to the NCUC. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return of 13.2 percent on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued an order dated October 26, 1992, authorizing a 12.8 percent return on common equity for the period October 31, 1986 through November 11, 1991, that resulted in a refund to North Carolina retail customers in 1992 of approximately $95 million, including interest.

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NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES

The Company has sold interests in both units of the Catawba Nuclear Station. The other owners of portions of the Catawba Nuclear Station and supplemental information regarding their ownership are as follows:

Owner	Ownership Interest in the Station
North Carolina Municipal Power Agency Number 1 (NCMPA)	37.5%
North Carolina Electric Membership Corporation (NCEMC)	28.125%
Piedmont Municipal Power Agency (PMPA)	12.5%
Saluda River Electric Cooperative, Inc. (Saluda River)	9.375%

Each participant has provided its own financing for its ownership interest in the plant.

The Company retains a 12.5 percent ownership interest in Catawba. As of December 31, 1992, $547,831,000 of Electric plant in service represents the Company's investment in Units 1 and 2 and nuclear fuel for those units. Accumulated depreciation and amortization of $198,268,000 associated with Catawba had been recorded as of year-end. The Company's share of operating costs of Catawba are included in the corresponding electric expenses in the Consolidated Statements of Income.

In connection with the joint ownership, the Company has entered into contractual agreements with the other joint owners to purchase annually declining percentages of the generating capacity and energy from the plant. These agreements were effective beginning with the commercial operation of each unit. Unit 1 and Unit 2 began commercial operation in June 1985 and in August 1986, respectively. Such agreements were established for 15 years for NCMPA and PMPA and 10 years for NCEMC and Saluda River.

Energy cost payments are based on variable operating costs, a function of the generation output. Capacity payments are based on the fixed costs of the plant. The estimated purchased capacity
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obligations through 1997 are $404,000,000 for 1993, $386,000,000 for 1994, $164,000,000 for 1995, $52,000,000 for 1996 and $42,000,000 for

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1997.

Effective in its November 1991 rate order, the North Carolina Utilities Commission (NCUC) reaffirmed the Company's recovery, on a levelized basis, of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners. The New NCUC rate order changed the levelized basis to a 15-year period ending 2001 for all of the other joint owners compared to the previous 15-year levelization period for NCMPA and PMPA and 10-year levelization period for NCEMC and Saluda River. The Public Service Commission of South Carolina (PSCSC), in its November 1991 rate order, reaffirmed the Company's recovery on a levelized basis of the capital costs of capacity purchased from the other joint owners. The new PSCSC rate order retained the levelized basis of a 7 1/2-year period ending April 1994 for PMPA and NCMPA; for NCEMC and Saluda River the new levelized basis reflects the projected purchased capacity payments for the twelve-month period ended October 1992. The Federal Energy Regulatory Commission granted the Company recovery on a levelized basis of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners over their contractual purchased power buy-back periods. As currently provided in rates in all jurisdictions, the Company recovers the costs of purchased energy and a portion of purchased capacity. The portion of costs not currently recovered through rates is being accumulated, and the Company is recording a net of a tax carrying charge on the accumulated balance. The Company recovers the accumulated balance including the carrying charge when the capacity payments drop below the levelized revenues.

For the years ended December 31, 1992, 1991 and 1990, the Company recorded purchased capacity and energy costs from the other joint owners of $514,300,000, $536,500,000 and $572,500,000, respectively. These amounts, adjusted for the cost of capacity purchased not reflected in current rates, are included in "Net interchange and purchased power" in the Consolidated Statements of Income. As of December 31, 1992 and 1991, $378,095,000 and $337,699,000 net of income taxes, respectively ($643,350,000 and $589,561,000, pretax, respectively), associated with the costs of capacity purchased not reflected in current rates had been accumulated in the Consolidated Balance Sheets as Purchased capacity costs.

NOTE 4. INCOME TAX EXPENSE

Income tax expense consisted of the following (dollars in thousands):

	1992	1991	1990
Income taxes related to electric expenses			

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Current income taxes			
Federal	$215,726	$232,121	$203,282
State	47,116	54,335	44,246
	262,842	286,456	247,528
Deferred taxes, net			
Excess tax over book depreciation	86,046	60,976	75,757
Property taxes	(15,499)	(11,987)	(10,852)
Catawba purchased capacity costs, net of amounts reflected in current rates	7,271	8,163	20,116
Amortization of canceled construction costs	(23,959)	(23,959)	(23,959)
Unbilled revenues	-	-	(13,929)
Other	(15,806)	(14,982)	(25,699)
	38,053	18,211	21,434
Investment tax credit			
Deferred	-	2,273	12,727
Amortization of deferrals (credit)	(11,262)	(13,480)	(15,977)
	(11,262)	(11,207)	(3,250)
Total income taxes related to electric expenses	289,633	293,460	265,712
Income taxes related to other income			
Income taxes-return on deferred Catawba purchased capacity costs	18,845	20,675	17,476
Income taxes-other, net	8,630	4,797	(2,192)
Income taxes-(credit)	(13,790)	(22,789)	(28,638)
Total income taxes related to other income	13,685	2,683	13,354
Total income tax expense	$303,318	$296,143	$252,358

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Total current income taxes were $258,800,000 for 1992, $268,686,000 for 1991 and $220,508,000 for 1990. Of these amounts, state income taxes were $44,149,000 for 1992, $48,671,000 for 1991 and $38,911,000 for 1990.

Total deferred income taxes were $55,780,000 for 1992, $38,664,000 for

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1991 and $35,100,000 for 1990. Of these amounts, deferred state income taxes were $13,786,000 for 1992, $10,833,000 for 1991 and $9,209,000 for 1990.

Income taxes differ from amounts computed by applying the statutory tax rate to pretax income as follows (dollars in thousands):

	1992	1991	1990
Income taxes on pretax income at the statutory federal rate of 34%	$ 275,876	$ 299,120	$ 268,786
Increase (reduction) in tax resulting from:			
Allowance for all funds used during construction (AFUDC)	(7,221)	(23,832)	(37,220)
Amortization of electric investment tax credit deferrals	(11,262)	(13,480)	(15,977)
AFUDC in book depreciation/ amortization	25,114	25,923	27,309
Deferred income tax flowback at rates higher than statutory	(21,685)	(22,561)	(21,638)
State income taxes, net of federal income tax benefits	37,878	39,345	31,818
Other items, net	4,618	(8,372)	(720)
Total income tax expense	$ 303,318	$ 296,143	$ 252,358

The Financial Accounting Standards Board has issued a statement that will require a change in the method of accounting for income taxes. While classification of certain items on the Consolidated Balance Sheets will change, principally due to certain items previously reported net of tax being reported on a gross basis, there will be no material effect on the Company's results of operations. The Company is required to implement this accounting standard in 1993.

NOTE 5. SHORT-TERM BORROWINGS AND COMPENSATING-BALANCE ARRANGEMENTS

To support short-term obligations, the Company had credit facilities of $329,385,000, $340,385,000 and $340,285,000 as of December 31, 1992, 1991 and 1990, with 49, 52 and 52 commercial banks, respectively. Included in these facilities is a three-year, $300,000,000 revolving credit agreement with the balance in separate, annually-renewable lines of credit. These facilities are on a fee or compensating-balance basis. No short-term debt resulting from these credit facilities was outstanding as of December 31, 1992, 1991 and 1990.

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Cash balances maintained at the banks on deposit were $7,243,000 as of December 31, 1992 and $7,842,000 as of December 31, 1991. Cash balances and fees compensate banks for their services, even though the Company has no formal compensating-balance arrangements. To compensate certain banks for credit facilities, the Company maintained balances of $509,000 as of December 31, 1992 and 1991. The Company retains the right of withdrawal with respect to the funds used for compensating-balance arrangements.

A summary of short-term borrowings is as follows (dollars in thousands):

	December 31, 1992	December 31, 1991	December 31, 1990
Amounts outstanding at end of period-average rate of 3.57% as of December 31, 1992, 4.65% as of December 31, 1991, and 7.96% as of December 31, 1990	$126,000	$ 86,000	$185,000
Maximum amount outstanding during the period	$219,000	$285,000	$250,321
Average amount outstanding during the period	$ 48,851	$ 92,090	$109,322
Weighted-average interest rate for the period - computed on a daily basis	4.02%	6.47%	8.21%

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NOTE 6. COMMON STOCK AND RETAINED EARNINGS

COMMON STOCK

Effective April 1, 1991, the Company began issuing common stock in lieu of purchasing shares on the open market for its various stock purchase plans. The Company discontinued issuances of common stock, effective December 1, 1991, and resumed open market purchases to satisfy the requirements of the various stock purchase plans. Except as discussed earlier, open market purchases were used to satisfy the requirements of the Company's various stock plans from 1990 through 1992.

For the past three years, the Company has issued common stock to satisfy

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the conversion rights of preference stock (see Note 7). During 1990, the Board of Directors declared a two-for-one split of Duke Power common stock. The Company issued common stock to satisfy the stock split.

As of December 31, 1992, a total of 7,004,659 shares was reserved for issuance to stock plans.

RETAINED EARNINGS

As of December 31, 1992, none of the Company's retained earnings were restricted as to the declaration or payment of dividends.

NOTE 7. PREFERRED AND PREFERENCE STOCK WITHOUT SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1992 and 1991:

	Par Value	1992 Shares	1991 Shares
Preferred Stock	$ 100	12,500,000	10,000,000
Preferred Stock A	25	10,000,000	10,000,000
Preference Stock	100	1,500,000	1,500,000

On April 6, 1992, the Company redeemed all outstanding shares of the Cumulative Preference Stock, 6 3/4% Convertible Series AA as its par value of $100 per share.

In 1992, 1991 and 1990, shares of preference stock were converted into shares of common stock as follows:

Year	Preference Shares	Common Shares
1992	19,060	159,386
1991	1,846	15,440
1990	2,564	21,434

Preferred and preference stock without sinking fund requirements as of December 31, 1992 and 1991 were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1992	1991
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
8.70% F	1970	600,000	-	60,000
8.20% G	1971	600,000	60,000	60,000

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7.80% H	1972	600,000	60,000	60,000
8.28% K	1977	500,000	50,000	50,000
8.84% M	1978	400,000	-	40,000
7.85% S	1992	600,000	60,000	-
7.72% (Preferred Stock A)	1992	1,600,000	40,000	-
Adjustable Rate A	1986	500,000	50,000	50,000
Auction Series A	1990	750,000	75,000	75,000
6 3/4%, AA Convertible	1969	20,164	-	2,016
Total			$ 500,000	$ 502,016

NOTE 8. PREFERRED STOCK WITH SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1992 and 1991:

	Par Value	1992 Shares	1991 Shares
Preferred Stock	$ 100	12,500,000	10,000,000
Preferred Stock A	25	10,000,000	10,000,000
Preferred Stock	100	1,500,000	1,500,000

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Preferred stock with sinking fund requirements as of December 31, 1992 and 1991 were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1992	1991
5.95% B (Preferred Stock A)	1992	800,000	$ 20,000	$ -
6.10% C (Preferred Stock A)	1992	800,000	20,000	-
6.20% D (Preferred Stock A)	1992	800,000	20,000	-
7.35% I	1973	408,000	-	40,800
8.20% J	1977	300,000	-	30,000
8.375% L	1978	320,000	-	32,000
8.84% N	1979	353,750	-	35,375
7.875% P	1986	485,000	48,500	-
		500,000	-	50,000
7.12% Q	1987	485,000	48,519	-
		500,000	-	50,000
7.50% R	1992	850,000	85,000	-

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6.20% T	1992	130,000	13,000	-
6.30% U	1992	130,000	13,000	-
6.40% V	1992	130,000	13,000	-
Less: Current sinking requirements				
7.35% I			-	(2,400)
8.20% J			-	(2,000)
8.375% L			-	(2,000)
8.84% N			-	(1,625)
7.875% P			(1,500)	(1,500)
Total			$279,519	$228,650

The annual sinking fund requirements through 1997 are $1,500,000 in 1993 and $3,000,000 in 1994, 1995, 1996 and 1997. Some additional redemptions are permitted at the Company's option. The Company required 15,000 shares of 7.12% Series Q Preferred Stock in 1992 to satisfy current sinking fund requirements.

The call provisions for the outstanding preferred stock specify various redemption prices not exceeding 105 percent of par value, plus accumulated dividends to the redemption date.

NOTE 9. LONG-TERM DEBT

First and refunding mortgage bonds outstanding as of December 31, 1992 and 1991 were as follows (dollars in thousands):

Series	Year Due	1992	1991
4 1/2%	1992	$ -	$ 50,000
4 1/4% B	1992	-	50,000
6.06%-6.23%	1994	81,700	81,700
6.47%-6.60%	1995	40,300	40,300
4 1/2%	1995	40,000	40,000
6.59%	1996	3,000	3,000
7 7/8%	1996	100,000	100,000
7 1/2% B	1997	-	100,000
5 3/8%	1997	72,600	72,600
5 5/8%	1997	100,000	-
6 3/8%	1998	68,500	68,500
7%	1999	56,075	56,075
7.5%	1999	100,000	-
8% B	1999	-	64,739

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6 1/4%	1999	65,000	-
7%	2000	100,000	-
7% B	2000	100,000	-
8 1/2%	2000	-	69,244
8 5/8% B	2000	-	95,635
7 1/2%	2001	97,900	97,900
7 3/8% B	2001	38,050	38,050
7 3/4%	2002	78,100	78,100
7 3/8% B	2002	67,900	67,900
7 3/4%	2003	94,872	94,872
8 1/8% B	2003	-	98,050
8%	2004	75,000	-
9 3/4%	2004	$ -	$ 95,623
7.37%-7.41%	2004	100,000	-
7%	2005	200,000	-
9 1/2%	2005	-	92,800
8 3/8%	2006	-	96,850
8 1/8%	2007	119,500	119,500
9 3/8%	2008	-	120,610
10 1/8% B	2015	-	50,000
9%	2016	175,000	175,000
8 1/2%	2017	150,000	150,000
9 5/8%	2020	200,000	200,000
10 1/8% B	2020	150,000	150,000
8 3/4%	2021	150,000	150,000
8 3/8% B	2021	150,000	150,000
8 5/8%	2022	100,000	-
8.95%	2027	15,925	15,994
Pollution-Control			
9 1/8%	2013	77,000	77,000
7.70%	2012	20,000	20,000
7.75%	2017	10,000	10,000
7.50%	2017	25,000	25,000
2.60% (1992)	2014	40,000	-
4.13% (1991)		-	40,000
Total		$3,061,422	$3,105,042

Substantially all electric plant was mortgaged as of December 31, 1992.
[HARDCOPY PAGE 33]

In 1992, the Company issued $100,000,000 in bonds through its medium-term notes facility with a maturity of 12 years and interest rates of 7.37 percent to 7.41 percent.

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As of December 31, 1992 and 1991, the Company had $40,000,000 in pollution-control revenue bonds backed by an unused, two-year revolving credit facility of $40,000,000 and $130,000,000 in commercial paper backed by an unused, three-year $130,000,000 revolving credit facility. These facilities are on a fee basis. Both the $40,000,000 in pollution-control bonds and the $130,000,000 in commercial paper are included in long-term debt.

The annual maturities of long-term debt, including capitalized lease principal payments, through 1997 are $6,827,000 in 1993; $102,748,000 in 1994; $81,913,000 in 1995, $104,781,000 in 1996 and $174,557,000 in 1997.

NOTE 10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following fair value disclosures are presented in accordance with a recent pronouncement of the Financial Accounting Standards Board effective in 1992. Estimated fair value amounts have been determined by the Company using available market information and appropriate valuation methodologies. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

OTHER INVESTMENTS

Included in "Other investments, at cost or less" at December 31, 1992 are financial instruments valued at approximately $55.7 million, which represents the present value of notes receivable from the other Catawba joint owners. The notes receivable from the other Catawba joint owners are non-negotiable instruments which were entered into as part of the sale of the interest in the Catawba Nuclear Station to the North Carolina Electric Membership Corporation and the Saluda River Electric Cooperative, Inc. (See Note 3).
Cash, Short-term investments and Notes payable
The carrying amount approximates fair value because of the short maturity of these instruments.

Long-term debt (excluding Capitalized leases) and Preferred stock with sinking fund requirements
Fair value is based on market price estimates. The fair market value of the Company's long-term debt and preferred stock with sinking fund requirements is approximately $3.3 billion and $0.3 billion, respectively, as of December 31, 1992.

As a result of substantial refinancing activity in 1992, the Company's book value of long-term debt and preferred stock is not materially different from fair market value.

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NOTE 11. CANCELED CONSTRUCTION PROJECTS

The construction of the Cherokee Nuclear Station was canceled. All retail jurisdictions have permitted recovery of the incurred costs. These costs are being amortized principally over a 10-year period that began in October 1983.

As of December 31, 1992 and 1991, the balances for this canceled project, net of amortization, were $28,889,000 and $67,302,000 net of income taxes, respectively ($46,779,000) and $109,152,000, pretax respectively).

NOTE 12. RETIREMENT BENEFITS

A. RETIREMENT PLAN

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own retirement plans, have a non-contributory, defined benefit retirement plan covering substantially all their employees. The benefit is based on years of creditable service and the employee's average compensation based on the highest compensation during a consecutive sixty-month period. Prior to 1992, benefits have been reduced by a Social Security adjustment for employees age sixty-five and over and for early retirees with no creditable service prior to September 1, 1980. During 1991, the Company amended its plan for employees who retire after December 31, 1991. The effect of this amendment was to reduce benefits by a Social Security adjustments for all retirees. The plan was amended in 1992 to permit participants with 30 years of creditable service to retire as early as age 51. The Company's policy is to fund pension costs as accrued.
[HARDCOPY PAGE 34]

Net periodic pension cost for the years ended December 31,1992, 1991 and 1990 included the following components (dollars in thousands):

	1992	1991	1990
Service cost benefit earned during the year	$35,701	$37,286	$33,259
Interest cost on projected benefit obligation	85,613	79,175	79,673
Actual return on plan assets	(50,897)	(127,978)	(33,506)
Amount deferred for recognition	(32,277)	(52,574)	(41,241)

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Expected return on plan assets	(83,174)	(75,404)	(74,747)
Net amortization	3,812	4,347	1,266
Net periodic pension cost	$41,952	$45,404	$39,451

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1992 and 1991 is as follows (dollars in thousands):

	1992	1991
Accumulated benefit obligation:		
Vested benefits	$ (920,228)	$ (802,851)
Nonvested benefits	(2,915)	(17,501)
Accumulated benefit obligation	$ (923,143)	$ (820,352)
Fair market value of plan assets, consisting primarily of short-term investment and cash equivalents, common stocks, real estate investments and government and government and industrial bonds	$ 980,661	$ 931,708
Projected benefit obligation	(1,132,410)	(1,054,825)
Unrecognized net experience (gain) loss	204,145	158,709
Unrecognized prior service cost (reduction) increase	(45,911)	(43,709)
Remaining unrecognized transitional obligation	1,202	1,335
(Accrued)/Prepaid pension cost	$ 7,687	$ (6,782)

In determining the projected benefit obligation, the weighted-average assumed discount rate used was 8.25 percent in 1992 and 1991 and 9.5 percent in 1990. The assumed increase in future compensation level determined on an age-related basis in 1992 and 1991 was 5.25 percent and 5.5 percent, respectively, for a participant of average. For 1990, an increase of 6.5 percent was assumed for all participant. The expected long-term rate of return on plan assets used in determining pension cost was 9.25 percent in 1992 and 1991 and 10.0 percent in 1990.

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B. POSTRETIREMENT BENEFITS

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own postretirement benefit plans, currently provides certain health care and life insurance benefits for retired employees. Substantially all of the Company's employees become eligible for these benefits if they elect early retirement at age fifty-five with ten years of service or if they retire sixty-five while working for the Company and are covered under the plan as an active employee. Employees retiring after January 1, 1992, receive a fixed Company allowance, based on years of service, to be used to pay medical insurance premiums. Also beginning in 1992, all new retires must have at least ten years of service be eligible for postretirement health benefits. Effective January 1, 1993, employees with 30 years or more of service will be able to retire as early as age 51 and receive postretirement benefits. The Company reserves the right terminate, suspend, withdraw, amend or modify the plans in whole part at any time. In 1992, the Company commenced funding the maximum amount allowable under section 401 (h) of the Internal Revenue Code, which provides for tax deductions for contributors and tax free accumulation of investment income. Such amounts partially fund the Company's medical postretirement benefits. The Company has also established a Retired Lives Reserve to partially fund its postretirement life insurance obligation, which has tax attributes similar to 401 (h) funding. The Company contributed $19,338,000 into these funding mechanisms for 1992.

In 1992, the Company implemented a new accounting standard that requires postretirement benefits to be recognized as earned by employees rather than recognized paid. Prior to 1992, the cost of retiree benefits was recognized as the benefits were paid. Amounts paid by the Company for 1991 and 1990 amounted to $11,900,00 and $10,200,000m respectively.
[HARDCOPY PAGE 35]

(CONTINUED FROM PAGE 34))

Net periodic postretirement benefit cost for the year ended December 31, 1992 included the following components (dollars in thousands):

	1992
Service cost benefit earned during the year	$ 4,644
Interest cost on projected benefit obligation	23,347
Actual return on plan assets	(2,953)
Amount deferred for recognition	1,061
Expected return on plan assets	(1,892)

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Straight line - 20 year amortization of transition obligation	13,479	
Amortization of prior service cost	160	
Net periodic postretirement benefit cost		$ 39,738

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1992 is as follows (dollars in thousands):

	1992
Fair market value of plan assets, consisting primarily of short-term investment and cash equivalents, common stocks, real estate investments and governments and government and industrial bonds	$ 41,634
Unrecognized net experience (gain)/loss	(2,501)
Actives eligible to retire	(14,954)
Actives not eligible to retire	(74,900)
Retirees and surviving spouses	(213,018)
Accumulated postretirement benefit obligation	(302,872)
Unrecognized prior service cost	2,083
Unrecognized transitional obligation	256,108
(Accrued) postretirement benefit cost	$ (5,548)

In determining the accumulated postretirement benefit obligation (APBO), the weighted-average assumed discount rate used was 8.25 percent in 1992. The future salary increase assumption is age-related. For the average age of 39, the rate of compensation increased 5.25 percent. The expected long-term rate of return on plan assets used in determining pension cost was 9.25 percent for 401 (h) assets and 7.125 percent for Retired Reserve assets.

The assumed health care cost trend rate for 1992 was approximately 14 percent. Medical trends for 1993 and forward decrease .5 percent to 1 percent per year. The trend rate of 5.5 percent, in the year 2002, remains fixed thereafter.

A one percent increase in the medical and dental trend rates produces a 6.04 percent ($1,689,000) increase in the aggregate service and interest cost. The increase in the APBO attributable to a one percent increase in the medical and dental trend rates is 6.91 percent ($20,924,000) as

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of December 31, 1992.

NOTE 13. COMMITMENTS AND CONTINGENCIES

A. CONSTRUCTION PROGRAM

Projected construction and nuclear fuel costs, both including allowance for funds used during construction, are $2.4 billion and $427 million, respectively, for 1993 through 1995. The program is subject to periodic review and revisions and actual construction costs incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

B. NUCLEAR INSURANCE

The Company maintains nuclear insurance coverage in three areas liability coverage, property, decontamination and decommissioning coverage, and extended accidental outage coverage to cover increased generating costs and/or replacement power purchases. The Company is being reimbursed by the other joint owners of the Catawba Nuclear Station for certain expenses associated with nuclear insurance premiums paid by the Company.

Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents the full limit of liability of approximately $7.8 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $7.6 billion, which will be increased by $63 million by $63 million (in 1988 dollars) as each additional commercial nuclear reactor is licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs, and public liability damages exceed primary insurances, licensees may be assessed up to $63 million (in 1988 dollars) for each off their licensed reactors, payable at a rate not exceed $10 million a year per licensed reactor for each incident. The $63 million amount is subject to indexing for inflation. This amount if further subject to a surcharge of 5 percent (which is included in the above $7.8 billion figure) if funds are insufficient to pay claims and associated costs. If retrospective premiums were to be assessed, the other joint owners of the Catawba Nuclear Station are obligated to

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assume their pro rata share of such assessment.

The Company if a member of Nuclear Mutual Limited (NML) which provides $500 million in primary property damage coverage for certain of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $29 million. This amount represents 5 times the Company's annual premium to NML.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases $1.325 billion of insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, the Company will be liable, on a pro rata basis, for additional assessments of up to $45 million. This amount is limited to 7.5 times the Company's annual premium to NEIL for excess property, decontamination and decommissioning liability insurance. The other share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to Catawba. The Company has also purchased an additional $400 million of excess property damage insurance for its Oconee and McGuire plants and $765 million for its Catawba plant through a pool of stock and mutual insurance companies.

In addition to the $1.325 billion in coverage through NEIL's excess property program and the $765 million in excess coverage mentioned above, and in lieu of primary property coverage through NML, the Company has placed $500 million through a pool to stock and mutual insurance companies for primary property insurance coverage associated with its interest in the Catawba Nuclear Station.

The Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. The Oconee, McGuire and Catawba Nuclear Stations are insured for up to approximately $2.5 million, $3.5 million and $3.5 million per unit per week, respectively, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100 percent for 52 weeks, and 67 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $27 million. This amounts represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to the joint ownership agreements.

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C. OTHER

The other joint owners of the Catawba Nuclear Station and the Company are involved in various proceedings related to the Catawba joint ownership agreements. The basic contention in each proceeding is that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other joint owners which have been approved by the Company's retail regulatory commissions (see Note 3). Although the other joint owners have not fully quantified the dollars associated with the presently outstanding proceedings, information associated with these proceedings indicates that the amount in contention could be as high as $360 million through December 31, 1992. Arbitration hearings were held in 1992 involving substantially all of the disputed amounts. The ultimate resolution of these matters cannot presently be determined; however, the Company is of the opinion that it has properly interpreted these agreements and that these costs would be included and recovered as part of the purchased capacity levelization consistent with prior orders of the retail regulatory commissions. Therefore, the ultimates resolution of these matters should not have a material adverse effect on the results of operations of financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

NOTE 14. OTHER INCOME

For the years ended December 31, 1992, 1991 and 1990, the Company recorded investment income of $24,952,000, $22,765,000 and $15,210,000, respectively ($18,168,000, $16,111,000 and $12,167,000 net of income taxes, respectively, as a component of "Other, net" in the Consolidated Statement of Income. The income is primarily from dividends and interest on securities. The taxes with the investment income are recorded as components of "Income taxes -- other, net" in the Company's Consolidated Statements of Income. For the year ended December 31, 1991, the Company recorded a net of tax carrying charge of $36,765,000 on costs incurred on the Bad Creek Hydroelectric Station after commercial operation but prior to recovery of costs through rates. This carrying charge is a component of "Other, net" in the Consolidated Statements of Income.

NOTE 15. RECLASSIFICATION

In the Consolidated Statements of Income for 1990, Electric revenues and

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Net interchange and purchased power include a reclassification for certain power transactions previously classified as Net interchange and purchased power prior to a 1990 FERC order.

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INDEPENDENT AUDITOR'S REPORT

DUKE POWER COMPANY:

We have audited the consolidated financial statements of Duke Power Company and subsidiaries (the Company) listed in the accompanying index on page 22. Our audits also included the supplemental schedules listed in the accompanying index on page 22. These financial statements and supplemental schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and supplemental schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1992 and 1991, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1992 in conformity with generally accepted accounting principles. Also, in out opinion, such supplemental schedules, when considered in relation to the basic consolidated financial statements taken as a whole present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE
Certified Public Accountants

Charlotte, North Carolina
February 15, 1993

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Power Company are prepared by management, which is responsible for their integrity and objectivity.

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The statements are prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions which should be included. The other information in the annual report is consistent with the financial statements. In preparing these statements management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed according to management's authorization. Internal accounting controls also provide reasonable assurance that transactions are recorded properly, so that financial statements can be according to generally accepted accounting principles. In addition, the Company's accounting controls provide reasonable assurance that errors or irregulars which could be material to the financial statements or are detected by employees within a timely period as they perform assigned functions. The Company's accounting controls are continually reviewed for effectiveness. In addition, written policies, standards and procedures, and a strong internal audit program augment the Company's accounting controls.

The Board of Directors pursues its oversight role for the financial statements through the audit program augment the Company's accounting controls.

The Board of Directors pursues its oversight role for the financial statements through the audit committee, which is composed entirely of directors who are not employees of the Company. The audit committee meets with management and internal auditors periodically to review the work of each group and to monitor each group's discharge of its responsibilities. The audit committee also auditors have free access to the audit committee and the Board of Directors to discuss internal accounting control, auditing and financial reporting matters without the presence of management.

DAVID L. HAUSER
Controller
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SELECTED FINANCIAL DATA

Quarterly Financial Data

Dollars in Thousands (except per-share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total

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1992 by quarter					
Electric Revenues	$981,330	$899,319	$1,139,525	$941,310	$3,961,48
Electric Operating Income	161,726	148,888	248,081	166,000	724,695
Net Income	106,365,	86,938	190,519	124,261	508,083
Earning Per Share	$8.45	$0.85	$0.85	$0.55	$2.21

1991 by quarter					
Electric Revenues (a)	$893,614	$898,839	$1,101,440	$923,067	$3,816,960
Electric Operating Income	166,713	161,893	241,221	136,996	706,823
Net Income	137,399	138,394	207,807	100,023	583,623
Earnings Per Share	$0.61	$0.61	$0.96	$0.42	$2.60

Generally, quarterly earnings fluctuate with seasonal weather conditions, timing of rate changes and maintenance of electric generating units, especially nuclear units.

(a) Total electric revenues for the quarters include a reclassification for 1991 for certain power transactions previously classified as Net interchange and purchased power prior to a 1990 FERC order.

SUBSIDIARY HIGHLIGHTS

The earnings contribution of the Company's subsidiaries and non-utility operations was $29.9 million in 1992, $26.9 million in 1991 and $26.2 million in 199. (a) (b) Highlights of selected subsidiaries are presented below.

ELECTRIC POWER SUPPLY

Nantahala Power and Light provides service to a five-county area in the western North Carolina mountains by its operation of 11 hydroelectric stations and purchases of supplemental power. (dollars in thousands)

	1992	1991	1990
Assets net of liabilities	$ 42,910	$ 39,384	$ 36,663
Net income	$ 3,526	2,271	$ 2,777
Number of employees (c)	191	194	194

FUNDS MANAGEMENT

Church Street Capital Corp. (CSCC) manages investment of funds for the

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Company and is the parent company of several subsidiaries. CSCC has no full-time employees. (dollars in thousands)

	1992	1991	1990
Short-term investments and marketable securities	$173,347	$120,303	$95,692
Investment income (after tax)	$ 5,404	$ 6,397	7,251

Highlights of CSCC's subsidiaries are presented below:

REAL ESTATE MANAGEMENT, LAND DEVELOPMENT

Crescent Resources, Inc. is engaged in forest management, real estate development, and sales and leasing. (dollars in thousands)

	1992	1991	1990
Assets net of liabilities	$110,949	$ 88,046	$69,662
Net income (before accounting change) (a)	$ 16,613	$ 9,661	$ 6,923
Number of employees (c)	73	69	65

ENGINEERING CONSTRUCTION, TECHNICAL SERVICES AND POWER DEVELOPMENT

Duke Engineering & Services, Inc. provides engineering, equipment procurement, construction management, start-up and operation support, quality assurance, and technical services for utility facilities other than coal-fired plants. Duke/Fluor Daniel, a joint venture with Fluor Daniel, Inc., provides similar engineering and construction expertise for coal-fired plants. Duke Energy Corp.. structures, finances and manages investments in electric generating facilities in the United States and abroad. Duke Energy's primary role is to manage contractual and other relationships necessary for a given project (e.g. project financing, siting, licensing, contract negotiations, construction management, long-term operations management, etc). (dollars in thousands)

	1992	1991	1990
Assets of liabilities	$ 36,687	$ 13,480	$ 30,889
Net income (loss)	$ 33	$ 1,512	(42)
Number of employees (c)	495	364	237

(a) 1991 excludes the cumulative effect of an accounting change of $6,727,000, after tax.
(b) The 1992 earnings contribution of the Company's subsidiaries and

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non-utility operations includes elimination of intercompany profit of $1,211,000, after tax.

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ITEM 9. CHANGES IN AN DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

No events necessary to be disclosed by the Company under this item have occurred.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

Information for this item concerning directors of the Company if set fourth in the sections entitled "Election of Directors" and "Information Regarding the Board the of Directors" in the proxy statement herein by reference.

Information concerning the executive officers of the Company is set forth under the section entitled "Executive Officers of the Company" in this annual report.

ITEM 11. EXECUTIVE COMPENSATION.

Information for this item is set forth in the section entitled "Executive Compensation" in the proxy statement of the Company relating to its 1993 annual meeting of shareholders, which is being incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

Information for this item is set forth in the sections entitled "Voting Securities Outstanding" and "Election of Directors" in the proxy statement of the Company relating to its 1993 annual meeting of shareholders, which is being incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIP AND RELATED TRANSACTIONS.

Information for this item is set forth in the section entitled "Election

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of Directors' in the proxy statement of the Company relating to its 1993 annual meeting of shareholders, which is being incorporated herein by reference

PART IV.

ITEM 14. EXHIBITS, CONSOLIDATED FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K.

Consolidated Financial Statements Financial Data and Supplemental Schedules included in Part II of this annual report are as follows.

Consolidated Financial Statements
Consolidated Statements of Cash Flows
for the Three Years Ended December 31, 1992
Consolidated Statements of Retained Earnings for the Three Years Ended December 31, 1992
Nots to Consolidated Financial Statements
Supplemental Financial Data (Unaudited)
Supplemental Schedules
Schedule V -- Property and Equipment for the Three Years Ended December 31, 1992
Schedule VI -- Accumulated Depreciation and Amortization of Property, Plant and Equipment for the Three Years Ended December 31, 1992
Schedule VIII -- Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31,1992
Schedule X -- Supplementary Consolidated Income Statement Information for the Three Years Ended December 31, 1992
Exhibit I -- Computation of Fully Diluted Earnings Per Share (Unaudited)
[HARDCOPY PAGE H1]

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or nots thereto.

Exhibits
(a) --See Exhibit List on page 46.

Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1992.
[HARDCOPY PAGE 46]

EXHIBIT LIST

The following exhibits indicated by an asterisk preceding the exhibit

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number are filed herewith. The balance of the exhibits have heretofore been filed with the Securities and Exchange Commission and pursuant to Rule 12b-32 are incorporated herein by reference.

Exhibit
Number

3-A --Restated Charter of registrant, dated as of January 1, 1979 (filed with Form S-7, File No. 2-63592, effective March 14, 1979, as Exhibit 2-B-1).

3-B --Articles of Amendment to the Articles of Incorporation dated May 4, 1981 (filed with Form 10-K for the year ended December 31, 1981, File No. 1-4928, as Exhibit 3-B).

3-C --Articles of Amendment to the Articles of Incorporation dated May 3, 1988 (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 3-C).

3-D --Articles of Amendment to the Articles of Incorporation dated May 16,1990 (filed with Form 10-K for the year ended December 31, 1990, File No.

3-E --Articles of Amendment to the Articles of Incorporated dated May 8, 1991 (filed with Form 10-K for the year ended December 31,1991, File No. 1-4928, as Exhibit 3-E).

(*)3-F --Articles of Amendment to the Articles of Incorporation dated May 15, 1992.

(*)3-G --Statement of Classification of Shares relating to the 7.875% Cumulative Preferred Stock, Series P (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 3-F).

3-H --Statement of Classification of Shares relating to the Adjustable Rate Cumulative Preferred Stock, Series A (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 3-G).

3-I --Statement of Classification of Shares relating to the 7.12% Cumulative Preferred Stock, Series Q (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 3-H).

3-J --Articles of Amendment of registrant dated October 22,1990 relating to the Preferred Stock, Auction Series A (filed with Form 10-K for the year ended December 31,1990, File No. 1-4928, as Exhibit 3-K).

(*)3-K --Articles of Amendment of registrant dated April 13,192 relating to the 7.50% Cumulative Preferred Stock, Series R.

(*)3-L --Articles of Amendment of registrant dated July 2, 1992 relating to the 7.85% Cumulative Preferred Stock, Series S.

(*)3-M --Articles of Amendment of registrant dated July 20, 1992 relating to the 7.72% Cumulative Preferred A, 1992 Series.

(*)3-N --Articles of Amendment of registrant dated August 20, 1992 relating to the 5.95% Cumulative Preferred Stock A, 1992 Series B.

(*)3-O --Articles of Amendment of registrant dated August 20, 1992

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relating to the 6.10% Cumulative Preferred Stock A, 1992 Series C.

(*)3-P --Articles of Amendment of registrant dated August 20,1992 relating to the 6.20% Cumulative Preferred Stock A, 1992 Series D.

(*)3-Q --Articles of Amendment of registrant dated November 10, 1992 relating to the 6.20% Cumulative Preferred Stock, Series T.

(*)3-R --Articles of Amendment of registrant dated November 10, 1992 relating to the 6.30% Cumulative Preferred Stock, Series U.

(*)3-S --Articles of Amendment of registrant dated November 10, 1992 relating to the 6.40% Cumulative Preferred Stock, Series V.

(*)3-T --Articles of Amendment of registrant dated February 9, 1993 relating to the &% Preferred Stock, Series W.

(*)3-U --By-Laws of registrant, as amended to date (filed with Form 10-K for the year ended December 31,1991, File No. 1-4928 as Exhibit 3-M.

[HARDCOPY PAGE 47]

Exhibit
Number

4-B-1 --First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated as of December 1,1927 (filed with Form S-1, File No. 2-7224, effective October 15,1947, as Exhibit 7(a)).

4-B-2 --Supplemental Indenture, dated as of March, 12,1930 supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).

4-B-3 --Supplemental Indenture, dated as of July 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15m 1947, as Exhibit 7(c)).

4-B-4 --Supplemental Indenture, dated as of December 1, 1935 supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(d)).

4-B-5 --Supplemental Indenture, dated as of September 1, 1936 supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).

4-B-6 --Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).

4-B-7 --Supplemental Indenture, dated as of April 1, 1944, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).

4-B-8 Supplemental Indenture, dated as of September 1, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).

4-B-9 --Supplemental Indenture, dated as of September 8, 1947 supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).

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4-B-10 --Supplemental Indenture, dated as of February 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).
4-B-11 --Supplemental Indenture, dated as of March 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).
4-B-12 --Supplemental Indenture, dated as of April 1, 1951, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(l)).
4-B-13 --Supplemental Indenture, dated as of September 1, 1953, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-13).
4-B-14 --Supplemental Indenture, dated as of October 1, 1954, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).
4-B-15 --Supplemental Indenture, dated as of January 1, 1955, supplementing said Mortgage (filed with Form S-9, No. 2-11297, effective December 30, 1954, as Exhibit 2-B-15).
4-B-16 --Supplemental Indenture, dated as of May 1, 1956, supplementing said Mortgage (filed with Form S-9, File No. 2-12402, effective April 26, 1956, as Exhibit 2-B-16).
4-B-17 --Supplemental Indenture, dated as of January 1, 1960 supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).
4-B-18 --Supplemental Indenture, dated as of February 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).
4-B-19 --Supplemental Indenture, dated as of February 1, 1962, supplementing said Mortgage (filed with Form S-9, File No. 2-20577, effective August 16, 1962, as Exhibit 2-B-20).
4-B-20 --Supplemental Indenture, dated as of August 1, 1962, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-19).
[HARDCOPY PAGE 48]

Exhibit
Number

4-B-21 --Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effectively August 23, 1966, as Exhibit 4-B-20).
4-B-22 --Supplemental Indenture, dated as of February 1, 1965, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-21).
4-B-23 --Supplemental Indenture, dated as of April, 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-8023, effective February 15, 1968, as Exhibit 2-B-25).
4-B-24 --Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No.

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2-313040 effective January 21 1969, as Exhibit 2-B-26).

4-B-25 --Supplemental Indenture, dated as of February 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-34289, effectively August 27, 1969, as Exhibit 2-B-27).

4-B-26 -- Supplemental Indenture, dated as of September 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-36095, effective February 16, 1970, as Exhibit 2-B-39).

4-B-27 --Supplemental Indenture, dated as of March 1, 1970, supplementing said Mortgage (filed with form S-7, File No. 2-37953, effectively July 28, 1970, as Exhibit 2-B-42).

4-B-28 --Supplemental Indenture, dated as of August 1, 1970, supplementing said Mortgage (filed with Form S-7, No. 2-39451, effective March 4, 1971, as Exhibit 2-B-28).

4-B-29 Supplemental Indenture, dated as of March 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-42404, effective December 7, 1971, as Exhibit 2-B-29).

4-B-30 --Supplemental Indenture, dated as of December 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-43122, effectively March 7, 1972, as Exhibit 2-B-30).

4-B-31 --Supplemental Indenture, dated as of April 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-46208, effective November 20, 1972, as Exhibit 2-B-31).

4-B-32 --Supplemental Indenture, dated as of December, 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-48058, effective June 5, 1973, as Exhibit 2-B-32).

4-B-33 --Supplemental Indenture, dated as of June 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-49333, effective November 5 1973, as Exhibit 2-B-33).

4-B-34 --Supplemental Indenture, dated as of November 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-50493, effectively August 25, 1974, as Exhibit 2-B-34).

4-B-35 -- Supplemental Indenture, dated as of May 1, 1974, supplementing said Mortgage (filed with Form S-7, File No. 2-52669, effective February 11, 1975, as Exhibit 2-B-35).

4-B-36 --Supplemental Indenture, dated as of February 1, 1975, supplementing said Mortgage (filed with form S-7, File No. 2-57118, effectively October 5, 1976, as Exhibit 2-B-36).

4-B-37 --Supplemental Indenture, dated as of July 1, 1975, supplementing said Mortgage (filed with Form S-7, No. 2-57118, effective October 5, 1976, as Exhibit 2-B-37).

4-B-38 Supplemental Indenture, dated as of October 1, 19761, supplementing said Mortgage (filed with Form S-7, File No. 2-59494, effective August 10, 1977, as Exhibit 2-B-38).

4-B-39 --Supplemental Indenture, dated as of September 1, 1977, supplementing said Mortgage (filed with Form S-7, File No. 2-61995, effective July 26, 1978, as Exhibit 2-B-39).

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4-B-40 --Supplemental Indenture, dated as of August 1, 1978,

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supplementing said Mortgage (filed with Form S-7, File No. 2-64541, effective June 7, 1979, as Exhibit 2-B-40).

4-B-41 --Supplemental Indenture, dated as of June 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-65371, effective October 2, 1979, as Exhibit 2-B-41).

4-B-42 --Supplemental Indenture, dated as of October 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-66659, effective March 12, 1980, as Exhibit 2-B-42).

4-B-43 --Supplemental Indenture, dated as of March 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-68571, effective August 19, 1980, as Exhibit 2-B-43).

4-B-44 --Supplemental Indenture, dated as of August 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-44).

4-B-45 --Supplemental Indenture, dated as of March 1, 1982, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-45).

4-B-46 --Supplemental Indenture, dated as of September 1, 1982 supplementing said Mortgage (filed with Form S-3, File No. 2-78882, effective August 30, 1982, as Exhibit 4-B-46).

4-B-47 Supplemental Indenture, dated as of May 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-47).

4-B-48 --Supplemental Indenture, dated as of September 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-48).

4-B-49 Supplemental Indenture, dated as of September 1, 1984, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effectively April 1, 1985, as Exhibit 4-B-49).

4-B-50 --Supplemental Indenture, dated as of March 1, 1985, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-50).

4-B-51 --Supplemental Indenture, dated as of December 1, 1985, supplementing said Mortgage (filed with Form S-3, File No. 33-5163, effective May 2, 1986, as Exhibit 4-B-51).

4-B-52 --Supplemental Indenture, dated as of April 1, 1986, supplementing said Mortgage (filed with Form S-3, File No. 33-5163, effective May 2, 1986, as Exhibit 4-B-52).

4-B-53 --Supplemental Indenture, dated as of May 1, 1986, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-53).

4-B-54 --Supplemental Indenture, dated as of June 1, 1986, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-54).

4-B-55 --Supplemental Indenture, dated as of February 1,1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit

4-B-55).

4-B-56 --Supplemental Indenture, dated as of February 15, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-56).

4-B-57 --Supplemental Indenture, dated as of March 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-57).

4-B-58 --Supplemental Indenture, dated of October 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1987, File No. 1-4928, as Exhibit 4-B-58).

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Exhibit
Number

4-B-59 --Supplemental Indenture, dated as of February 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1989, File No. 1-4928, as Exhibit 4-B-59).

4-B-60 --Supplemental Indenture, dated as of March 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-60).

4-B-61 Supplemental Indenture, dated as of May 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, Exhibit 4-B-61).

4-B-62 --Supplemental Indenture, dated as of May 15, 1990 supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-62).

4-B-63 --Supplemental Indenture, dated as of March 1, 1991, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-63).

4-B-64 --Supplemental Indenture, dated as of July 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-64).

4-B-65 --Supplemental Indenture, dated as of December 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-65).

4-B-66 --Supplemental Indenture, dated as of March 1, 1992, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1991, File No. 1-4928, as Exhibit 4-B-66).

4-B-67 --Supplemental Indenture, dated as of June 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-67).

4-B-68 --Supplemental Indenture, dated as of July 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-68).

4-B-69 Supplemental Indenture, dated as of September 1, 1992,

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supplementing said Mortgage (filed with Form S-3, File No. 33-53308, effective November 24, 1992, as Exhibit 4-B-69).

(*)4-B-70 --Supplemental Indenture, dated as of February 1, 1993, supplementing said Mortgage.

10-A --Agreement, dated march 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).

10-B --Agreement, dated as of August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K the month of August 1980, File No. 1-4928).

10-C --Agreement, dated as of October 14, 1980, between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

10-D --Agreement, dated as of October 14, 1980, between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

(*)10-E(1) --Employees' Stock Ownership Plan.

(*)10-F(1) --Employee Incentive Plan.

(*)10-G(1) --1992 Executive Long-Term Incentive Plan.

(*)10-H(1) --Supplemental Security Plan.

(*)10-I(1) --Stock Purchase-Savings Program for Employees.

(*)10-J(1) --Employees' Retirement Plan.

(*)10-K(1) --Supplemental Retirement Plan.

(*)10-L(1) --Compensation Deferral Plan.

(*)10-M(1) --Compensation Deferral Plan for Outside Directors.

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Exhibit
Number

(*)10-N(1) --Retirement Plan for Outside Directors.

(*)10-O(1) --Supplementary Defined Contribution Plan for Employees.

(*)10-P(1) --Director's Charitable Giving Program.

(*)10-Q(1) --Vacation Banking Plan.

(*)10-R(1) --Estate Conservation Plan.

(*)10-S(1) --Supplemental Insurance Plan.

(*)10-T(1) --Group Life Insurance Plan.

(*)10-U(1) --Stock Ownership Plan for Nonemployee Directors

(*)12 --Computation of Ratio of Earnings to Fixed Charges.

(*)24 --Consent of Independent Auditors.

(*)25(a) --Manually signed copies of powers of attorney authorizing Lewis F. Camp, Jr. and others to sign the annual report on behalf of the registrant and certain of its directors and officers.

(*)25-(b) --Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.

(1) Compensatory plan or arrangement required to be filed as an exhibit.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Charlotte and State of North Carolina on the 25th day of February, 1993.

By: DUKE POWER COMPANY
(Registrant)

W. S. LEE
Chairman of the Board and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

W. S. LEE
Chairman of the
Board and President
(Principal Executive
Officer)
February 25, 1993

R. J. OSBORNE
Vice President and Chief
Financial Officer (Principal
Financial Officer)
February 25, 1993

DAVID L. HAUSER
Controller (Principal
Accounting Officer)
February 25, 1993

G. ALEX BERNHARDT
CRANDALL C. BOWLES
W. A. COLEY
JOHN L. FRALEY
STEVE C. GRIFFITH, JR.
W. H. GRIGG
PAUL H. HENSON
GEORGE DEAN JOHNSON, JR.
JAMES V. JOHNSON

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W. W. JOHNSON
W. S. LEE
MAX LENNON
BUCK MICKEL
REECE A. OVERCASH, JR.
R. B. PRIORY
A Majority of the Directors
February 25, 1993

LEWIS F. CAMP, JR., by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons pursuant to powers of attorney duly executed by the registrant and such persons, filed with the Securities ad Exchange Commission as an exhibit hereto.

/s/ Lewis F. Camp, Jr.
Attorney-in-fact

SEC ONLINE INC.
SCHEDULE INDEX

NUMBER	DESCRIPTION	PAGE
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VI	ACCUMULATED DEPRECIATION OF PROPERTY, PLANT AND EQUIPMENT	52
VIII	VALUATION AND QUALIFYING ACCOUNTS	53
X	SUPPLEMENTARY INCOME STATEMENT INFORMATION	53

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SCHEDULE V - PROPERTY, PLANT AND EQUIPMENT
(Dollars in thousands)

	Balance Beginning

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Description	of Year	Additions
For the year Ended December 31, 1992		
Electric Plant in Service-At Original Cost		
Production	$ 6,228,232	$ 121,364
Transmission	1,300,021	34,235
Distribution	3,335,893	236,777
General	894,685	53,114
Miscellaneous	71,380	221
Nuclear Fuel	2,004,441	264,506
Total electric plant in service	13,834,652	710,217
Construction Work in Progress	501,942	(11,534)
Other Property-At Cost		
Water plant	35,009	830
Transit plant	1,499	-
Total other property	36,508	830
Total plant	$14,373,102	$ 699,513
For the Year Ended December 31, 1991		
Electric Plant in Service-At Original Cost		
Production	$ 4,965,205	$ 1,229,905
Transmission	1,223,152	80,809
Distribution	3,079,886	283,097
General	844,706	98,575
Miscellaneous	111,972	(2,229)
Nuclear Fuel	1,870,975	133,466
Total electric plant in service	12,095,896	1,823,623
Construction Work in Progress	1,521,391	(1,019,449)
Other Property-At Cost		
Water plant	33,886	1,312
Transit plant	2,782	-
Total other property	36,668	1,312
Total plant	$13,653,955	$ 805,486
For the Year Ended December 31,1990		
Electric Plant in Service-At Original		

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Cost		
Production	$ 4,880,284	$ 117,684
Transmission	1,152,588	76,324
Distribution	2,773,018	334,983
General	788,160	73,985
Miscellaneous	144,933	3,862
Nuclear Fuel	1,694,967	176,008
Total electric plant in service	11,433,950	782,846
Construction Work in Progress	1,255,232	266,159
Other Property-At Cost		
Water plant	33,006	926
Transit plant	2,824	-
Total other property	35,830	926
Total plant	$12,725,012	$ 1,049,931

(TABLE CONTINUED)

	Retirements	Add (Deduct)	Balance End of Year
For the year Ended December 31, 1992			
Electric Plant in Service-At Original Cost			
Production	$ 2,521	$60,086	$ 6,407,161
Transmission	2,114	(474)	1,331,668
Distribution	53,227	(208)	3,519,235
General	25,046	(51,042)	871,711
Miscellaneous	174	(7,314)	64,113
Nuclear Fuel			2,268,947
Total electric plant in service	83,082	1,048	14,462,835
Construction Work in Progress	-	-	490,408
Other Property-At Cost			
Water plant	227	43	35,655
Transit plant	1,499	-	-
Total other property	1,726	43	35,655
Total plant	$ 84,808	$ 1,091	$14,988,898

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For the Year Ended December 31, 1991			
Electric Plant in Service-At Original Cost			
Production	$ 7,356	$40,478	6,228,232
Transmission	2,627	(1,313)	1,300,021
Distribution	27,681	591	3,335,893
General	47,163	(1,433)	894,685
Miscellaneous	201	(38,162)	71,380
Nuclear Fuel	-	-	2,004,441
Total electric plant in service	85,028	161	13,834,652
Construction Work in Progress	-	-	501,942
Other Property-At Cost			
Water plant	189	-	35,009
Transit plant	1,283	-	1,499
Total other property	1,472	-	36,508
Total plant	$ 86,500	$ 161	$14,373,102

For the Year Ended December 31,1990			
Electric Plant in Service-At Original Cost			
Production	$ 63,285	$30,522	$ 4,965,205
Transmission	4,830	(930)	1,223,152
Distribution	29,158	1,043	3,079,866
General	25,012	7,573	844,706
Miscellaneous	-	(36,823)	111,972
Nuclear Fuel	-	-	1,870,975
Total electric plant in service	122,285	1,385	12,095,896
Construction Work in Progress	-	-	1,521,391
Other Property-At Cost			
Water plant	51	5	36,668
Transit plant	42	-	2,782
Total other property	93	5	36,668
Total plant	$ 122,378	$ 1,390	$13,653,955

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SCHEDULE VI-ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

(Dollars in thousands)

Description	Beginning of Year	Clearing and Other Depreciation Accounts	
For the Year Ended December 31,1992			
Accumulated Depreciation of			
Electric Plant			
Production	$2,119,391	$226,137	$ -
Transmission	531,332	33,213	-
Distribution	979,805	122,311	-
General	229,400	26,612	4,758
Miscellaneous	49,850	-	357
	3,909,778	408,273	5,115
Accumulated Amortization of			
Limited Term Plant	5,983	-	687
Accumulated Amortization of			
Nuclear Fuel	1,722,192	-	151,638
	5,637,953	408,273	157,440
Accumulated Depreciation of			
Water Plant	8,094	691	-
Accumulated Depreciation of			
Transit Plant	1,420	2	-
Total Accumulated Depreciation	$5,647,467	$408,966	$157,440
For the Year Ended December 31, 1991			
Accumulated Depreciation of			
Electric Plant			
Production	$1,902,284	$198,372	$ -
Transmission	500,555	34,589	-
Distribution	896,226	109,461	-
General	221,691	30,920	13,393
Miscellaneous	88,258	-	352
	3,609,014	373,342	13,745

1992 COPYRIGHT SEC ONLINE, INC., 1

Accumulated Amortization of Limited Term Plant	5,108	-	497
Accumulated Amortization of Nuclear Fuel	1,552,977	-	169,215
	5,167,099	373,342	183,457
Accumulated Depreciation of Water Plant	7,578	682	-
Accumulated Depreciation of Transit Plant	2,662	41	-
Total Accumulated Depreciation	$5,177,339	$374,065	$183,457

For the Year Ended December 31,1990

Accumulated Depreciation of Electric Plant			
Production	$1,753,706	$181,151	$ -
Transmission	471,754	33,655	-
Distribution	826,188	98,993	-
General	193,387	30,839	15,324
Miscellaneous	124,792	-	349
	3,369,827	344,638	15,673
Accumulated Amortization of Limited Term Plant	4,585	-	522
Accumulated Amortization of Nuclear Fuel	1,397,475	-	155,502
	4,771,887	344,638	171,697
Accumulated Depreciation of Water Plant	6,967	657	-
Accumulated Depreciation of Transit Plant	2,602	102	-
Total Accumulated Depreciation	$4,781,456	$345,397	$171,697

(TABLE CONTINUED)

Description	Retirements	Other Changes Add (Deduct)	Balance End of Year
For the Year Ended December 31,1992			
Accumulated Depreciation of Electric Plant			
Production	$ 11,572	$ (5,637)	$2,328,319

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1992 COPYRIGHT SEC ONLINE, INC., 1

Transmission	3,208	(269)	561,068
Distribution	49,127	419	1,053,408
General	18,929	853	242,694
Miscellaneous	-	(44,670)	5,537
	82,836	(49,304)	4,191,026
Accumulated Amortization of Limited Term Plant	4	(187)	6,479
Accumulated Amortization of Nuclear Fuel	-	-	1,873,830
	82,840	(49,491)	6,071,335
Accumulated Depreciation of Water Plant	221	21	8,585
Accumulated Depreciation of Transit Plant	1,449	27	-
Total Accumulated Depreciation	$ 82,840	$ (49,443)	$6,079,920

For the Year Ended December 31, 1991

Accumulated Depreciation of Electric Plant			
Production	$ 13,054	$ 31,789	$2,119,391
Transmission	2,901	(911)	531,332
Distribution	26,787	905	979,805
General	35,269	(1,335)	229,400
Miscellaneous	-	(38,760)	49,850
	78,011	(8,312)	3,909,778
Accumulated Amortization of Limited Term Plant	-	378	5,983
Accumulated Amortization of Nuclear Fuel	-	-	1,722,192
	78,011	(7,934)	5,637,953
Accumulated Depreciation of Water Plant	166	-	8,094
Accumulated Depreciation of Transit Plant	1,283	-	1,420
Total Accumulated Depreciation	$ 79,460	(7,934)	$5,647,467

For the Year Ended December 31,1990

Accumulated Depreciation of Electric Plant	

1992 COPYRIGHT SEC ONLINE, INC., 1

Production	$ 69,913	$ 37,340	$1,902,284
Transmission	5,597	743	500,555
Distribution	28,154	(801)	896,226
General	17,484	(375)	221,691
Miscellaneous	-	(36,883)	88,258
	121,148	24	3,609,014
Accumulated Amortization of Limited Term Plant	(1)	-	5,108
Accumulated Amortization of Nuclear Fuel	-	-	1,552,977
	121,147	24	5,167,099
Accumulated Depreciation of Water Plant	46	-	7,578
Accumulated Depreciation of Transit Plant	42	-	2,662
Total Accumulated Depreciation	$ 121,235	$ 24	$5,177,339

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SCHEDULE VIII - VALUATION AND QUALIFYING ACCOUNTS RESERVES
(Dollars in thousands)

Description	Balance Beginning of Year	Balance End of Year
For the Year Ended December 31, 1992		
Reserves Related to Assets on Balance Sheet	$25,592	$ 10,730
Other Reserves		
Operating Reserves (1)	$67,577	$ 78,103
For the Year Ended December 31,1991		
Reserves Related to Assets on Balance Sheet	$43,712	$ 25,592
Other Reserves		
Operating Reserves (1)	$59,527	$ 67,577
For the Year Ended December 31, 1990		
Reserves Related to Assets on Balance Sheet	$24,352	$ 43,712

Other Reserves		
Operating Reserves (1)	$85,703	$ 59,527

(1) Principally consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits and Other Liabilities," in the Balance Sheets.

SCHEDULE X - SUPPLEMENTARY CONSOLIDATED INCOME STATEMENT INFORMATION

	Year Ended December 31,		
	1992	1991	1990
	(Dollars in thousands)		
Taxes, other than payroll and income taxes:			
Real and personal property	$ 82,327	$ 68,117	$ 66,072
State and city franchise	84,033	89,307	86,943
Other	11,663	12,531	10,983
Total	$178,023	$169,955	$163,998

SEC ONLINE INC.
EXHIBIT INDEX

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AND CERTAIN OF ITS DIRECTORS AND OFFICERS 58

25B CERTIFIED COPY OF RESOLUTION OF THE BOARD OF DIRECTORS OF THE REGISTRANT AUTHORIZING POWER OF ATTORNEY 59

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EXHIBIT I

DUKE POWER COMPANY
COMPUTATION OF FULLY DILUTED EARNINGS PER SHARE - (Unaudited)

This calculation is submitted in accordance with Regulation S-K under the Securities Exchange Act of 1934, although not required by footnote 2 to paragraph 14 of Opinion No. 15 of the Accounting Principles Board because it results in dilution of less than 3%.

	Year Ended December 31,		
	1992	1991	1990
	(Dollars in thousands except per share figures)		
Fully Diluted: (1)			
Earnings applicable to common stock (2)	$451,676	$528,940	$485,572
Add: Dividends on Preference Stock, 6 3/4 % Convertible Series AA	-	140	160
Earnings as adjusted for computation	$451,676	$529,080	$485,732
Average common shares outstanding twelve months (thousands) (2)	204,819	203,431	202,570
Add: Common shares required for conversion of Preference Stock, 6 3/4% Convertible Series AA, $100 par, 500,000 shares authorized (no shares outstanding as of December 31, 1992) (3)	-	169	184

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1992 COPYRIGHT SEC ONLINE, INC., 1

Common shares as adjusted for computation	204,819	203,600	202,754
Fully diluted earnings per share	$ 2.21	$ 2.60	$ 2.40

(1) All common stock data reflects the two-for-one split of the Company's common stock on September 28, 1990.

(2) These figures agree with the related amounts in the Consolidated Statements of Income.

(3) All shares were converted in April 1992. The conversion price used to convert the Preference Stock, 6 3/4% Convertible Series AA, into shares of common stock was $11.95.

[HARDCOPY PAGE EXH1]

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Dollars in Thousands)

	Year Ended December 31		
	1992	1991	1990
Earnings Before Income Taxes (1)	$ 811,401	$ 879,766	$ 790,546
Fixed Charges	327,308	308,862	297,116
Total	$1,138,709	$1,188,628	$1,087,662
Fixed Charges			
Interest on long-term debt	$ 257,149	$ 269,419	$ 255,334
Other interest	47,972	22,780	24,306
Amortization of debt discount, premium, and expense	8,497	5,242	4,998
Interest component of rentals	13,690	11,421	12,478
Fixed Charges	$ 327,308	$ 308,862	$ 297,116
Ratio of Earnings to Fixed Charges	3.48	3.85	3.66

1992 COPYRIGHT SEC ONLINE, INC., 1

(TABLE CONTINUED)

	Year Ended December 31	
	1989	1988
Earnings Before Income Taxes (1)	$ 867,641	$ 827,732
Fixed Charges	266,497	254,622
Total	$1,134,138	$1,082,354
Fixed Charges		
Interest on long-term debt	$ 232,510	$ 230,403
Other interest	18,203	7,979
Amortization of debt discount, premium, and expense	4,677	4,658
Interest component of rentals	11,107	11,582
Fixed Charges	$ 266,497	$ 254,622
Ratio of Earnings to Fixed Charges	4.26	4.25

(1) Includes cumulative effect of the accounting change for unbilled revenues for 1988.

[HARDCOPY PAGE EXH2]

EXHIBIT 24

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 33-15183, 33-19274, 33-45502, 33-50584 and 33-53308 of Duke Power Company on Form S-3 and in Post-Effective Amendment No. 10 to Registration Statement No. 2-72172 of Duke Power Company on Form S-8 of our report dated February 15, 1993, appearing in this Annual Report on Form 10-K of Duke Power Company for the year ended December 31, 1992.

DELOITTE & TOUCHE
Charlotte, North Carolina
February 25, 1993

[HARDCOPY PAGE EXH3]

1992 COPYRIGHT SEC ONLINE, INC., 1

EXHIBIT 25(A)
Power of Attorney

Annual Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 1992

(Annual Report)

The undersigned, DUKE POWER COMPANY, a North Carolina Corporation, and certain of its officers and/or directors, do each hereby constitute and appoint W. S. Lee, Richard J. Osborne, Lewis F. Camp, Jr., David L. Hauser, and each of them, to act as attorneys-in-fact for and in the respective names, places and stead of the undersigned, to execute, seal, sign and file with the Securities and Exchange Commission the Annual Report of said Duke Power Company on Form 10-K and any and all amendments thereto, hereby granting to said attorneys-in-fact, and each of them, full power and authority to do and perform all and every act and thing whatsoever requisite, necessary or proper to be done in and about the premises, as fully to all intents and purposes as the undersigned, or any of them, might or could do if personally present, hereby ratifying and approving the acts of said attorneys-in-fact.

Executed the 25th day of February, 1993.

(*) SEC ONLINE NOTE: THIS POWER OF ATTORNEY HAS ALSO BEEN ISSUED, SIGNED, AND EXECUTED FOR THE FOLLOWING INDIVIDUALS ON THE DATES INDICATED. FOR SIMPLICITY, SEC ONLINE HAS ENTERED IT ONCE.

(Corporate Seal)

DUKE POWER COMPANY

/s/ W. S. LEE
Chairman and President

ATTEST:
[/s/SIGNATURE ILLEGIBLE]
Assistant Secretary

(*) RICHARD J OSBORNE VICE PRESIDENT/ CHIEF FINANCIAL OFFICER
(*) DAVID L HAUSER CONTROLLER
(*) ROBERT L ALBRIGHT DIRECTOR
(*) G ALEX BERNHARDT DIRECTOR
(*) CRANDALL C BOWLES DIRECTOR
(*) WILLIAM A COLEY DIRECTOR
(*) JOHN L FRALEY DIRECTOR

(*) STEVE C GRIFFITH JR DIRECTOR
(*) W H GRIGG DIRECTOR
(*) PAUL H HENSON DIRECTOR
(*) GEORGE R HERBERT DIRECTOR
(*) GEORGE DEAN JOHNSON JR DIRECTOR
(*) JAMES V JOHNSON DIRECTOR
(*) WW JOHNSON DIRECTOR
(*) MAX LENNON DIRECTOR
(*) BUCK MICKEL DIRECTOR
(*) REECE A OVERCASH JR DIRECTOR
(*) RICHARD B PRIORY DIRECTOR

[HARDCOPY PAGE EXH4]

EXHIBIT 25B
EXTRACT FROM THE MINUTES OF A MEETING
OF THE BOARD OF DIRECTORS OF DUKE POWER COMPANY
HELD ON FEBRUARY 23, 1993

Mr. Lee then referred to the Company's Annual Report on Form 10-K. He presented to the meeting a draft dated February 17, 1993, of the Form 10-K, indicating that it would be in order to approve such document subject to management's changes as may be necessary or advisable. Mr. James V. Johnson then advised that the Audit Committee had reviewed the Form 10-K and found it to be in order and, after discussion, upon his motion, duly seconded, it was

RESOLVED, that the Form 10-K, as presented to the meeting, with such changes therein as may be deemed necessary or advisable by the officers of the Company be and hereby is in all respects approved; and

FURTHER RESOLVED, that the Power of Attorney as presented to the meeting and executed by all the Directors present be and hereby is approved in form and content for purposes of filing the Form 10-K with the Securities and Exchange Commission.

I, LEWIS F. CAMP, JR., Secretary of Duke Power Company do hereby certify that the foregoing is a full, true, and complete extract from the minutes of the meeting of the Board of Directors of said Company held on February 23, 1993, containing all resolutions adopted with respect to the Form 10-K, at which meeting a quorum was present.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the corporate seal of said DUKE POWER COMPANY, this 26th day of February, 1993.

/s/LEWIS F CAMP JR
Secretary

(SEAL)

LENGTH: 40659 words

LOAD-DATE: May 4, 1993

LANGUAGE: ENGLISH

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10-K

FILING-DATE: 03/01/93 DOCUMENT-DATE: 12/31/92

DUKE POWER CO
TICKER-SYMBOL: DUK EXCHANGE: NYS

422 SOUTH CHURCH STREET
CHARLOTTE, NC 28242
704-373-4011

INCORPORATION: NC

COMPANY-NUMBER: FORBES NUMBER: SA240
CUSIP NUMBER: 26439910
DUNS NUMBER: 00-699-6052
COMMISSION FILE NO.: 1-4928
IRS-ID: 56-0205520

SIC: SIC-CODES: 4911, 4941
PRIMARY SIC: 4911

INDUSTRY-CLASS: ELECTRIC SERVICES

FYE: 12/31

AUDITOR: DELOITTE & TOUCHE

STOCK-AGENT: FIRST UNION NATIONAL BANK

COUNSEL: STEVE C. GRIFFITH - GENERAL COUNSEL

INVESTOR-CONTACT: ALLEN J. STEWART - INVESTOR RELATIONS

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SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K(MARK ONE)

(X) ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (FEE REQUIRED)

For the fiscal year ended December 31, 1993

Commission file number 1-4928

1993 COPYRIGHT SEC ONLINE, INC., 1

DUKE POWER COMPANY

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

NORTH CAROLINA	56-0205520
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(IRS EMPLOYER IDENTIFICATION NO.)
422 SOUTH CHURCH STREET CHARLOTTE, NORTH CAROLINA	28242-0001
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES)	(ZIP CODE)

704-594-0887
(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common Stock, without par value	New York Stock Exchange
Preferred Stock A, par value $25	
7.72%, 1992 Series	New York Stock Exchange
6.375% 1993 Series	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(G) OF THE ACT:
TITLE OF CLASS

Preferred Stock, par value $100

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days.

Yes X No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (X)

Estimated aggregate market value of the voting stock held by nonaffiliates of the registrant at March 29, 1994 $ 7,375,999,091

Number of shares of Common Stock, without par value, outstanding at March 29, 1994 204,859,339

DOCUMENTS INCORPORATED BY REFERENCE:

The registrant is incorporating herein by reference certain sections of its proxy statement relating to the 1994 annual meeting of shareholders

1993 COPYRIGHT SEC ONLINE, INC., 1

to provide information required by the following parts of this annual report:

Part III – Item 10., Directors and Executive Officers of the Registrant
– Item 11., Executive Compensation
– Item 12., Security Ownership of Certain Beneficial Owners and Management
– Item 13., Certain Relationships and Related Transactions

[HARDCOPY PAGE H2]

: The following index is part of the original document. Page numbers have been kept for your convenience in locating data referred to within the text and are identified as (SOURCE PAGE #) in the upper left-hand corner of each page. To access these pages, refer to SEC Online's Table of Contents.

DUKE POWER COMPANY
FORM 10-K
ANNUAL REPORT TO
THE SECURITIES AND EXCHANGE COMMISSION
FOR THE YEAR ENDED DECEMBER 31, 1993

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PART I.

ITEM 1. BUSINESS.

Duke Power Company (the Company) is engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both States known as the Piedmont Carolinas. Its service area, approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4.8 million and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville and Spartanburg in South Carolina. During 1993, the Company's electric revenues amounted to approximately $4.3 billion, of which about 70 percent was derived from North Carolina and about 30 percent from South Carolina. The Company ranks sixth in the United States among investor-owned utilities in kilowatt-hour sales. Its executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242-0001 (Telephone No.

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704-594-0887). THE STATISTICS PRESENTED HEREIN DO NOT INCLUDE INFORMATION RELATING TO THE COMPANY'S UTILITY SUBSIDIARY, NANTAHALA POWER AND LIGHT COMPANY, UNLESS OTHERWISE INDICATED. (SEE "ENERGY REQUIREMENTS AND CAPABILITY.")

SERVICE AREA

The Company supplies electric service directly to approximately 1.7 million residential, commercial and industrial customers in more than 200 cities, towns and unincorporated communities in North Carolina and South Carolina. Electricity is sold at wholesale to nine incorporated municipalities and to several private utilities. In addition, in 1993 approximately 9% of total sales were made through contractual arrangements to former wholesale municipal or cooperative customers of the Company who had purchased portions of the Catawba Nuclear Station (collectively, the "Other Catawba Joint Owners") (See "Joint Ownership of Generating Facilities.")

The Company's service area is undergoing increasingly diversified industrial development. The textile, manufacture of machinery and equipment, chemical and chemical related industries are of major significance to the economy of the area. Other industrial activity includes the paper and allied products, rubber and plastic products and various other light and heavy manufacturing and service businesses. The largest industry served by the Company is the textile industry, which accounted for approximately $488 million of the Company's revenues for 1993, representing 11 percent of electric revenues and 40 percent of electric industrial revenues.

ENERGY REQUIREMENTS AND CAPABILITY

The following table sets forth the Company's generating capability at December 31, 1993, its sources of electric energy for 1993, and certain information presently projected for 1994:

	GENERATING CAPABILITY – KW(A)	
		PROJECTED
	ACTUAL	DECEMBER 31,
SOURCE	DECEMBER 31, 1993	1994
Coal	7,510,000	7,656,000
Nuclear (b)	7,054,000	7,054,000
Hydro and other	3,281,000(c)	3,281,000(c)
Total (b)	17,845,000	17,991,000
Less: Other Catawba Joint Owners' share		
Plus: Purchases from Other Catawba Joint Owners		
Purchased power and net interchange		
Total		

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(TABLE CONTINUED)

SOURCE	GENERATION – KWH (MILLIONS)(D) ACTUAL 1993
Coal	34,097
Nuclear (b)	48,211
Hydro and other	1,625
Total (b)	83,933
Less: Other Catawba Joint Owners' share	13,821
Plus: Purchases from Other Catawba Joint Owners	8,810
Purchased power and net interchange	1,750
Total	80,672

(a) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(b) Nuclear capability and related generation for 1993 and projected for 1994 give no effect to the joint ownership of the Catawba Nuclear Station. (See "Joint Ownership of Generating Facilities.")

[HARDCOPY PAGE 2]

(c) Includes Bad Creek and Jocassee pumped storage hydroelectric stations at licensed generating capabilities of 1,065,000 KW and 610,000 KW, respectively.

(d) Excludes firm purchases. (See "Energy Management and Future Power Needs.") Nantahala Power and Light Company (NP&L), which operates 11 hydroelectric stations and buys supplemental power to provide service to its 51,000 mostly residential customers located in five counties in western North Carolina, operates as a separate subsidiary of the Company. The Company is supplying supplemental power to NP&L under the terms of an interconnect agreement approved by the Federal Energy Regulatory Commission (FERC).

The Company has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this agreement.

According to industry statistics published in 1993, the Company ranked

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first in the nation in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Published rankings indicate that individual units at Marshall Steam Station ranked first, second and sixth most efficient in the nation in 1992. The Company's nuclear system continued its tradition of operating efficiency, operating at 78 percent of capacity for the year, in comparison with the industry's most current average capacity factor of 71 percent for 1992.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The Company currently forecasts a 2.1 percent compound annual growth in peak load through 2008. This amount is not reduced by those future demand-side management program contributions considered resources for meeting peak demand (See "Energy Management and Future Power Needs"). The 1992-1993 winter peak load of 13,314,000 KW occurred on February 19, 1993. On July 29, 1993, the Company experienced its summer peak load of 15,720,000 KW during unusually hot weather. A new all-time peak load of 16,070,000 KW occurred on January 19, 1994 during extremely cold weather.

RATE MATTERS

The North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSCSC) must approve the Company's rates for retail sales within the respective states. FERC must approve the Company's rates for sales to wholesale customers, including the contractual arrangements between the Company and the Other Catawba Joint Owners.

Rate requests filed by the Company in its most recent general rate case in 1991 with the NCUC, PSCSC and FERC were principally designed to reflect the Company's investment in the Bad Creek Hydroelectric Station. Rate orders issued by the NCUC and PSCSC in November, 1991 recognized costs of the Bad Creek Hydroelectric Station, including an amortization of costs deferred between commercial operation and the rate order, which the Company had requested. The Company's wholesale customers challenged its proposed rate increase and in 1991 FERC issued an order that accepted the Company's proposed rates for filing. A negotiated settlement with these customers, which provided for an increase in wholesale rates consistent with the increase in retail rates, was approved by FERC and became effective in April 1992 (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Liquidity and Resources –RATE MATTERS").

In its most recent general rate case, the NCUC authorized a jurisdictional rate of return on common equity of 12.50 percent and the PSCSC authorized a jurisdictional rate of return on common equity of 12.25 percent.

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The North Carolina Supreme Court, on April 22, 1992, remanded for the second time the Company's 1986 rate order to the NCUC. In its ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return of 13.2 percent on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order dated October 26, 1992, authorizing a 12.8 percent return on common equity for the period October 31, 1986 through November 11, 1991, that resulted in a refund to North Carolina retail customers in 1992 of approximately $95 million, including interest.

FUEL COST ADJUSTMENT PROCEDURES. The Company has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The NCUC ordered the Company to follow these procedures in its

[HARDCOPY PAGE 3]

August 1986 order, which was effective for periods beginning January 1, 1986. The prospective adjustment in rates of past over-or under-recovery of fuel costs was challenged in the North Carolina courts. North Carolina adopted legislation assuring the legality of such adjustments, which contains a sunset provision effective June 30, 1997.

CONSTRUCTION WORK IN PROGRESS (CWIP). The NCUC is permitted in its discretion to include CWIP in rate base after giving consideration to the public interest and the Company's financial stability. The PSCSC may include CWIP in rate base in its discretion.

ENERGY MANAGEMENT AND FUTURE POWER NEEDS

The Company's strategy for meeting customers' present and future energy needs is composed of three components: demand-side resources, purchased power resources and supply-side resources. By utilizing these resources, the Company expects to maintain a reserve margin of approximately 20 to 25 percent of its anticipated peak load requirements through 1996.

Demand-side management programs are a part of meeting the Company's future power needs. These programs benefit the Company and its customers by providing for load control through interruptible control features, shifting usage to off-peak periods, increasing usage during off-peak periods, and by promoting energy efficiency. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help to reduce their electric bills. Demand-side management programs such as Industrial Interruptible Service and Residential Load Control can be used to

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manage capacity availability problems. Energy-efficiency programs such as high-efficiency chillers, high-efficiency heat pumps and high-efficiency air conditioners are other examples of current demand-side management programs. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. As additional demand-side costs are incurred, the Company ultimately expects recovery of associated costs, which are currently being deferred, through rates. The annual costs deferred, including the return, were approximately $26 million in 1993 and $18 million in 1992.

The Company continues to engage in a comprehensive energy management program as part of its Integrated Resource Plan. Integrated Resource Planning is the process used by utilities to evaluate a variety of resources. The goal is to provide adequate and reliable electricity in an environmentally responsible manner through cost-effective power management. In January 1993, the PSCSC issued an order approving the Company's 1992 Integrated Resource Plan as reasonable, and approving a "shared savings" proposal for accomplishments made in the Company's demand-side management programs. In June 1993, the NCUC approved the 1992 plan, including the shared savings mechanism. The Company's current plan reduces supply side requirements in excess of 1,900 megawatts by the year 2000 due to the Company's effective use of demand side options.

The purchase of capacity and energy is also an integral part of meeting future power needs. The Company currently has under contract 500 megawatts of capacity from other generators of electricity.

The Company's construction program and the estimated construction costs set forth below are subject to continuing review and are revised from time to time in light of changes in load forecasts, the Company's financial condition (including cash flow, earnings and levels of rates), changing regulatory and environmental standards (See "Regulation --ENVIRONMENTAL MATTERS") and other factors.

[HARDCOPY PAGE 4]

Projected construction and nuclear fuel costs, excluding costs related to portions of the Catawba Nuclear Station owned by the Other Catawba Joint Owners, for each of 1994, 1995 and 1996 and for the three-year period 1994-1996, as now scheduled, are as follows (in millions of dollars):

TYPE OF FACILITIES	1994	1995	1996	TOTAL

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Generation	$475	$436	$243	$1,154
Transmission	44	49	55	148
Distribution	200	211	233	644
Other	120	120	82	322
Total	$839	$816	$613	$2,268
Nuclear Fuel	$143	$123	$128	$ 394

The Company's procedures for estimating construction costs (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs and allowances for inflation.

The Company is building a combustion turbine facility in Lincoln County, North Carolina to provide capacity at periods of peak demand. The Lincoln Combustion Turbine Station will consist of 16 combustion turbines with a total generating capacity of 1,184 megawatts. The estimated total cost of the project is approximately $500 million. Current plans are for ten units to begin commercial operation by the end of 1995 and the remaining six to begin commercial operation before the end of 1996. During 1991, the NCUC granted the Certificate of Public Convenience and Necessity and the North Carolina Division of Environmental Management issued a final air permit for the facility. The issuance of the final air permit for the facility has been appealed. Legal proceedings with regard to the appeal are ongoing. The Company believes the permit will be upheld.

The Company has nearly completed a Plant Modernization Program (PMP) to improve the efficiency and reliability of 15 older coal-fired generating units. These units, once modernized, will help the Company meet anticipated future demand. The cost of this program is estimated to average approximately $200-$300 per installed KW, a fraction of the cost of building new plants. As of December 31, 1993, eleven coal-fired units with a nameplate generating capability of 1,241,000 KW had been returned to the system. It is anticipated that three additional coal-fired generating units with nameplate generating capability of 160,000 KW will be returned to the system during 1994. The Company expects the final unit remaining in the PMP after 1994, which unit has 40,000 KW of nameplate generating capability, to be returned to the system in 1995.

JOINT OWNERSHIP OF GENERATING FACILITIES

In order to reduce its need for external financing, the Company, through several transactions beginning in 1978, sold an 87 1/2 percent undivided interest in the Catawba Nuclear Station to the Other Catawba Joint Owners.

These transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion

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of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use (whether or not the facility is generating electricity) that portion of the capacity not then contractually required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The transactions also include a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station of the Company, which provides for an exchange of 50 percent of each Other Catawba Joint Owner's retained capacity from its ownership interest in the Catawba units for like amounts of capability and output from units of the McGuire Nuclear Station. The implementation of the reliability exchange has not had nor does the Company anticipate that such implementation will have a material effect on earnings.

The Other Catawba Joint Owners and the Company are involved in various proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding is that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the Other Catawba Joint Owners which have been previously approved by the Company's retail regulatory commissions (See Note 3, "Notes to Consolidated Financial Statements"). The Company and two of the four Other Catawba Joint Owners have entered into a proposed settlement agreement

[HARDCOPY PAGE 5]

which, if approved by the regulators, will resolve all issues in contention in such proceedings between the Company and these owners. The Company recorded a liability as an increase to Other current liabilities on its Consolidated Balance Sheets of approximately $105 million in 1993 to reflect this proposed settlement. In addition, future estimated obligations in connection with the settlement are reflected in estimates of purchased capacity obligations in Note 3, "Notes to Consolidated Financial Statements". As the Company expects the costs associated with this settlement will be recovered as part of the purchased capacity levelization, the Company has included approximately $105 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Although the two Other Catawba Joint Owners, who are not parties to the above settlement, have not fully quantified the dollars associated with their claims in the presently outstanding proceedings, information associated with these proceedings indicates that the amount in

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contention could be as high as $110 million, through December 31, 1993. Arbitration hearings were held in 1992 involving substantially all of the disputed amounts, and a decision interpreting the language of the agreements on certain of these matters was issued on October 1, 1993. Further proceedings will be required to determine the amounts associated with this decision as it relates to these owners, some of which may involve refunds. However, the Company expects the costs associated with this decision will be included in and recovered as part of the purchased capacity levelization consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

FUEL SUPPLY

The Company presently relies principally on nuclear and coal for the generation of electric energy. The Company's reliance on oil and gas is minimal.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

GENERATION BY SOURCE
YEAR ENDED DECEMBER 31

	1993	1992	1991
Coal	40.6%	36.7%	34.2%
Nuclear	57.5	61.0	63.8
Oil and Gas	–	–	–
All Fuels (cost based on weighted average)	98.1	97.7	98.0
Hydroelectric*	1.9	2.3	2.0
	100.0%	100.0%	100.0%

(TABLE CONTINUED)

COST OF FUEL PER NET KWH GENERATED (MILLS)
YEAR ENDED DECEMBER 31

	1993	1992	1991
Coal	16.06	16.49	17.04
Nuclear	5.41	5.41	5.66
Oil and Gas	–	–	–
All Fuels (cost based on weighted average)	9.85	9.58	9.64
Hydroelectric*			

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* Generating figures are net of that output required to replenish pumped storage units during off-peak periods.

COAL. The Company obtains a large amount of its coal under long-term supply contracts with mining operators utilizing both underground and surface mining. The Company has on hand an adequate supply of coal.

The Company's long-term supply contracts, all of which have price adjustment and price renegotiation provisions, have expiration dates ranging from 1995 to 2003. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers for quantities and qualities of coal required. However, due to the Clean Air Act Amendments of 1990, fuel premiums may be required as contracts are renewed. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. The Company's short-term requirements have been and will be fulfilled with spot market purchases. The average sulfur content of coal being purchased by the Company is approximately 1 percent. Such coal satisfies the current emission limitation for sulfur dioxide for existing facilities. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues --The Clean Air Act Amendments of 1990.")

NUCLEAR. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed

[HARDCOPY PAGE 6]

from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations. Based upon current projections, these contracts will meet the Company's requirements through the following years:

NUCLEAR STATION	URANIUM MATERIAL	CONVERSION SERVICE	ENRICHMENT SERVICE	FABRICATION SERVICE
Oconee	1997	1994	1995	2006
McGuire	1997	1994	1995	1999
Catawba	1997	1994	1995	1999

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Uranium material requirements will be met through various supplier contracts, with uranium material produced primarily in the U.S., Canada and Australia. The Company believes that it will be able to renew contracts as they expire or to enter into similar contractual arrangements with other nuclear fuel materials and services suppliers. Short-term requirements have been and will be fulfilled with uranium spot market purchases.

The Company purchased uranium material during 1993 at an average price of approximately $28 per pound. The Company's material nuclear supply contracts generally contain FORCE MAJEURE provisions.

The Nuclear Waste Policy Act of 1982 requires that the Department of Energy (DOE) begin disposing of spent fuel no later than January 31, 1998. The Company has entered into the required contracts with the DOE for the disposal of nuclear fuel and began making payments in July 1983 for disposal costs of fuel currently being utilized. These payments, combined with a one-time payment for disposal costs of fuel consumed prior to April 7, 1983, have totaled about $525 million through 1993. In November 1989, the DOE released a report which indicated that it expects that a facility for spent fuel disposal will not be available until the year 2010. The DOE stated further that it planned an initiative to establish a monitored retrievable storage facility, with a target operation date of 1998, for earlier acceptance of spent fuel from utilities. The Company believes that it will be able to provide adequate on-system storage capacity until such time as the DOE begins receiving spent fuel.

REGULATION

The Company is subject to the jurisdiction of the NCUC and the PSCSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC, the Environmental Protection Agency (EPA) and state environmental agencies and to the jurisdiction of the Nuclear Regulatory Commission (NRC) as to design, construction and operation of its nuclear power facilities. The Company is exempt from regulation as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA), except with respect to the acquisition of the securities of other public utilities.

ENVIRONMENTAL MATTERS. The Company is subject to federal, state, and local regulations with regard to air and water quality, hazardous and

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solid waste disposal, and other environmental matters. North Carolina has enacted a declaration of environmental policy requiring all state agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. South Carolina law also requires consideration by the PSCSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed major utility facilities, which include certain generation and transmission facilities. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. In 1993, the Company's construction costs for environmental protection totaled approximately $18 million, while the on-going environmental operation costs were approximately $20 million. The Company's 1994 -1996 construction program includes costs for environmental protection which are estimated to be approximately $101 million, including $22.3 million in 1994, $41.8 million in 1995 and $36.9 million in 1996. These costs include expenditures to begin compliance with the Clean Air Act Amendments of 1990. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. Therefore, the Company may have to revise the estimates in response to developments in these and other areas.

[HARDCOPY PAGE 7]

AIR QUALITY. See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -The Clean Air Act Amendments of 1990" for a discussion of the Company's plans for compliance with federal clean air standards.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1987 (otherwise known as the "Clean Water Act") require permits for facilities that discharge into waters, to ensure compliance with its provisions. The Company holds numerous such permits, and such permits are reissued periodically. The Federal Water Pollution Control Act is scheduled for reauthorization by Congress in 1994. Until Congress acts upon the reauthorization, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

OTHER ENVIRONMENTAL REGULATIONS. Contingencies associated with environmental matters are principally related to possible obligations

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to remove or mitigate the effects on the environment resulting from the disposal of certain substances at contamination sites.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as "Superfund", requires any individual or entity which may have owned or operated a contaminated site, as well as transporters or generators of hazardous wastes which were sent to such site, to assume joint and several responsibility for remediation of the site. Such parties are known as "potentially responsible parties" (PRPs). In 1993, Duke as a PRP, resolved litigation at a Superfund site in West Virginia, and is currently participating in a PRP group with regard to a Superfund site in Concord, North Carolina. Additionally, the Company is a DE MINIMUS contributor at two sites in Pennsylvania. The Company is also a PRP at contamination sites in Charlotte, North Carolina and Lenoir, North Carolina, which will likely be remediated in accordance with state acts which are similar to CERCLA. While the total cost of remediation at these federal and state contamination sites may be substantial, the Company shares probable liability with other PRPs, many of which have substantial assets. Other contamination sites relate to the Company's operation of manufactured gas plant (MGP) sites prior to the early 1950s, some of which are still owned by the Company and some of which are now owned by third parties. The Company is participating in a state-sponsored program which will result in the investigation and, where appropriate, remediation of MGP sites. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

CERCLA is scheduled for reauthorization by Congress in 1994. Until Congress acts upon the reauthorization, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

GENERAL. Over the past few decades, the issue of the possible health effects of electric and magnetic fields has generated a number of generally inconclusive studies, some public concern and litigation as well as legislative action in some states regarding high voltage transmission lines. The impact of this issue on the Company cannot presently be determined.

NUCLEAR FACILITIES. The Company's nuclear facilities are subject to continuing regulation by the NRC.

The steam generators at the McGuire and Catawba Nuclear Stations have experienced stress corrosion cracking in their tubes. Stress corrosion cracking is a phenomenon that typically occurs in tight U-bends, at tube support plates, and where tubes are attached to the tube sheets. Stress corrosion cracking has been identified as a problem in steam generators of certain designs, including those at the McGuire and Catawba Stations. The Company believes that the stress corrosion

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cracking is caused by defective design, workmanship and materials used by the manufacturer of the steam generators. Both primary side and secondary side cracking and corrosion have been observed in the steam generators at the McGuire and Catawba Stations. In addition, recent inspections at McGuire Units 1 and 2 have revealed a different type of secondary side stress corrosion cracking in the free-span area of the steam generator tubes located on the "cold-leg" side of those Units (cold-leg free-span cracking). The Company conducts tests at each refueling outage to determine the extent of stress corrosion cracking during the preceding fuel cycle.

The steam generators at Catawba Unit 2 have certain design differences from those at Catawba Unit 1 or either McGuire Unit, but it is too early in the life of Catawba Unit 2 to determine the extent to which stress corrosion cracking will be a problem.

[HARDCOPY PAGE 8]

Although the Company has taken steps to mitigate the effects of stress corrosion cracking in the McGuire and Catawba steam generator tubes, including examining the steam generator tubes at each refueling outage, tube plugging, tube sleeving, more stringent water chemistry control, shot peening, and tight U-bend heat treatment, further stress corrosion cracking in the McGuire Units 1 and 2 and Catawba Unit 1 steam generators appears likely. Potential consequences of future stress corrosion cracking include extensive tube plugging and sleeving, additional water chemistry control, additional inspections and testing resulting in longer outages, mid-cycle outages, reduction in plant output, and requests for license amendments. The Company has compared the cost of continued repair of the steam generators with the cost of early steam generator replacement and has determined that for McGuire Units 1 and 2 and Catawba Unit 1, the most cost-effective alternative is to replace the steam generators as soon as it is feasible to do so.

The Company has begun planning for the replacement of steam generators and has set the following schedule to begin the process: McGuire Unit 1 --1995; Catawba Unit 1 --1996; McGuire Unit 2 --1997. The order of replacement is subject to change based on performance of the existing steam generators and on the overall performance of the three units. The Company has signed an agreement with Babcock & Wilcox International to purchase 12 replacement steam generators for the McGuire and Catawba Stations. Each unit's steam generator replacement is expected to take approximately four months and cost approximately $170 million, excluding the cost of replacement power and without consideration of reimbursement of applicable costs by the Other Catawba Joint Owners of Catawba Unit 1. Stress corrosion problems are excluded under the nuclear insurance policies. The Company anticipates that the replacement of the steam generators should not have a material adverse

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effect on the Company's results of operations or financial position. Because Catawba Unit 2 has not shown the degree of stress corrosion cracking which has occurred in McGuire Units 1 and 2 and Catawba Unit 1, the Catawba Unit 2 steam generators have not been scheduled for replacement.

The Company in connection with its McGuire and Catawba stations and on behalf of the Other Catawba Joint Owners commenced a legal action on March 22, 1990, in the United States District Court for the District of South Carolina (Charleston Division) seeking damages from Westinghouse Electric Corporation (Westinghouse) for supplying to the McGuire and Catawba Stations steam generators that were alleged to be defective in design, workmanship and materials, and that will require replacement well short of their stated design life. In the action, the Company sought a judgment against Westinghouse for damages of approximately $600 million, including the cost of necessary remedial measures, the cost of replacement of steam generators and payment for replacement power during the outages to accomplish replacement. In addition to these damages, the Company sought punitive or treble damages and attorneys' fees. The lawsuit was settled on March 17, 1994. (See "Subsequent Events.")

NUCLEAR DECOMMISSIONING COSTS. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $955 million stated in 1990 dollars. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The Other Catawba Joint Owners are liable for providing decommissioning related to their ownership interest in the Catawba Nuclear Station. Both the NCUC and the PSCSC have granted the Company recovery of the estimated site-specific decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume that units will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 -- 2013, Oconee 3 --2014; McGuire 1 --2021, McGuire 2 --2023; and Catawba 1 --2024, Catawba 2 --2026.

The Nuclear Regulatory Commission (NRC) issued a rulemaking in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1993, the Company expensed approximately $52.5 million which was contributed to the external funds and accrued an additional $5 million to the internal reserve. The balance of the external funds as of December 31, 1993, was $118.5 million. The balance of the internal reserve as of December 31, 1993, was $200

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million and is reflected in Accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the estimated site-specific decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 4.5 percent to 5.5 percent, are currently sufficient to provide for the cost of decommissioning based on Company's current decommissioning schedule.

[HARDCOPY PAGE 9]

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid approximately $8.3 million during 1993 related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of approximately $117 million in the Consolidated Balance Sheets.

NUCLEAR INSURANCE. For a discussion of the Company's nuclear insurance coverage, see "Notes to Consolidated Financial Statements, Note 13 -- Commitments and Contingencies --Nuclear Insurance."

HYDROELECTRIC LICENSES. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for the Keowee-Toxaway Project for a term expiring in 2016, covering the Keowee Hydro Station and the Jocassee Pumped Storage Station for a combined total of 769,500 KW, on the upper tributaries of the Savannah River in northwestern South Carolina. Additionally, the Company is the licensee through 2027 for the Bad Creek Hydroelectric Station which uses Lake Jocassee as its lower reservoir and has a nameplate rating of 1,065,000 KW. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

INTERCONNECTIONS

The Company has major interconnections and arrangements with its

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neighboring utilities which it considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

COMPETITION

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems, rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSCSC, respectively, of all areas outside municipalities in such states to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSCSC. In addition, the Company is engaged in continuing competition with various natural gas providers.

The Energy Policy Act of 1992 has far-reaching implications for the Company by moving utilities toward a more competitive environment. The Act reformed certain provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and removed certain regulatory barriers. For example, the Act allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to registration under PUHCA as an electric utility holding company. The Act requires transmission of power for third parties to wholesale customers, provided that the reliability of service to the utility's local customer base is protected and the local customer base does not subsidize the third-party service. Although the Act does not require transmission access to retail customers, states can authorize such transmission access to and for retail electric customers.

The electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive

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pressure on the price of electricity, utilities might be forced to reduce their assets to reflect market basis if such basis is less than cost. Discontinuation of cost-based regulation could also require some utilities to write off their regulatory assets. Management cannot predict the potential impact, if

[HARDCOPY PAGE 11]

any, of these competitive forces on the future financial position and results of operations of the Company. However, the Company is continuing to position itself to effectively meet these challenges by maintaining prices that are regionally and nationally competitive.

NON-UTILITY ACTIVITIES

The Company is engaged in a variety of non-utility operations, including real estate development and forest management, marketing of electrical appliances, management of passive financial investments, developing and investing in electric generation and transmission facilities outside the Company's service area and providing engineering and technical services. Most of the Company's non-utility operations are organized in separate subsidiaries. Subsidiary and diversified operations contributed $22 million after tax to corporate earnings in 1993.

A major part of the future growth in the electric power market is anticipated to be outside the traditional regulated framework and, to a large extent, outside the United States. The Company, through its subsidiaries, is participating in these international opportunities and continues participating in domestic opportunities to provide additional value to its shareholders. Internationally, the Company is seeking opportunities to provide engineering consulting services, construction, operation and maintenance of generating facilities, and ownership of transmission and generating facilities. Although these opportunities are concentrated in areas that utilize the Company's expertise, they present different and greater risks than the Company's core business. The Company considers only opportunities in which the expected return is commensurate with the risks, and makes efforts to mitigate such risks.

In March 1993, Duke Energy Group (DEG) invested $25 million in convertible preferred stock of J. Makowski & Company (Makowski), a developer of natural gas-fired electric projects, and is providing $10.2 million in credit support for a Makowski project. Additionally, DEG has one seat on the Board of Directors of Makowski.

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In June 1993, after a competitive bidding process, the Argentine government awarded the right to buy 65 percent of the stock of Compania de Transporte de Energia Electrica en Alta Tension S. A. (Transener) to a consortium led by DEG. Transener is Argentina's primary transmission company. It employs about 1,100 persons, and has 6,867 kilometers of 500 kilovolt lines, 284 kilometers of 220 kilovolt lines, and 27 substations. The consortium assumed ownership and operation of the system on July 16, 1993.

Another consortium, also led by DEG, was awarded the majority ownership and operation of Hidroelectrica Piedra del Aguila S.A. on November 29, 1993. Hidroelectrica Piedra del Aguila S.A. owns a hydroelectric facility located in southwestern Argentina. When fully operational in 1995, the facility will have a capacity of 1,400 megawatts. The consortium assumed ownership of 59 percent of the stock of Hidroelectrica Piedra del Aguila S.A., and took over operation of the hydroelectric complex on December 29, 1993.

EMPLOYEES

At December 31, 1993, the Company employed 18,274 full-time persons, which includes 789 full-time employees of subsidiaries and affiliates. About 2,000 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW). The Company reached a new labor agreement with the IBEW, effective October 1, 1993, for a one year term.

The Company has been engaged in a concentrated effort to more efficiently and effectively utilize its resources through better work practices. During the first quarter of 1993, the Company offered a Limited Period Separation Opportunity Program (LPSO) which gave employees the option of leaving the Company for a lump sum severance payment and, for qualifying employees, enhanced retirement benefits. On March 15, 1994, the Company announced plans to offer Enhanced Voluntary Separation (EVS), a severance package, for employees who choose to leave the Company voluntarily during the second quarter of 1994. Implementing programs such as LPSO, EVS and other efficiency practices has resulted in continued workforce reduction and in streamlined workflows. The number of full-time employees has decreased to the present level from 19,945 at year-end 1990. The 1990 amount included 496 employees of subsidiaries and affiliates.

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SUBSEQUENT EVENTS

On January 25, 1994, the Board of Directors selected William H. Grigg, Vice Chairman of the Board, to succeed William S. Lee as Chairman of the Board, President and Chief Executive Officer, effective at the Annual Meeting of Shareholders to be held on April 28, 1994. Mr. Lee will serve the Company as a consultant after that date until his retirement following his 65th birthday in June 1994.

On March 2, 1994, the Duke Endowment announced its intention to diversify its investment portfolio by selling up to 16 million shares of its Duke Power Common Stock. A registration statement was filed with the Securities and Exchange Commission on that day and underwriting agreements were entered into on March 29, 1994 relating to the sale of 14 million of such shares, with over-allotment options of up to 2 million shares. The Duke Endowment will retain approximately 10 million shares after the sale (assuming the over-allotment options are exercised), and has announced that it has no present intention to dispose of any additional shares of Common Stock.

On March 17, 1994, the Company, together with the Other Catawba Joint Owners, settled the lawsuit initiated by the Company on March 22, 1990 against Westinghouse Electric Corporation seeking damages for supplying to the McGuire and Catawba Nuclear Stations steam generators that were alleged to be defective in design, workmanship and materials and that would require replacement well short of their stated design life. While the terms of the settlement may not be disclosed pursuant to court order, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company. Such settlement will not have a material effect on the Company's results of operations or financial position. (See "Regulation --Nuclear Facilities" and "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues --Stress Corrosion Cracking.")

[HARDCOPY PAGE 12]

(graphic--full page map showing the Duke Power Service Area)

[HARDCOPY PAGE 13]

DUKE POWER COMPANY

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OPERATING STATISTICS
YEAR ENDED DECEMBER 31

	1993	1992	1991
SOURCES OF ELECTRIC ENERGY			
Millions of kilowatt-hours:			
Generated – net output:			
Coal	34,097	28,999	26,455
Nuclear (a)	48,211	48,238	49,328
Hydro (b)	1,582	1,834	1,545
Oil and gas	43	5	7
Total generation	83,933	79,076	77,335
Purchased power and net interchange (c)	1,750	1,403	587
Total output	85,683	80,479	77,922
Less: Other Catawba Joint Owners' share	13,821	14,313	12,280
Plus: Purchases from Other Catawba Joint Owners	8,810	9,466	8,525
Total sources of energy	80,672	75,632	74,167
Line loss and company usage	(4,614)	(4,590)	(4,280)
Total kilowatt-hour sales (d)	76,058	71,042	69,887
AVERAGE COST PER TON OF COAL BURNED	$ 42.21	$ 43.47	$ 45.21
ELECTRIC ENERGY SALES			
Millions of kilowatt-hours:			
Residential	19,465	17,789	17,918
General service	16,904	15,818	15,586
Industrial			
Textile	11,954	11,685	11,315
Other	16,244	15,356	14,955
Other energy and wholesale (c)(e)	11,337	10,360	10,132
Total			

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kilowatt-hour sales billed	75,904	71,008	69,906
Unbilled kilowatt-hour sales	154	34	(19)
Total kilowatt-hour sales (d)	76,058	71,042	69,887
ELECTRIC REVENUE			
Thousands of dollars:			
Residential	$1,424,173	$1,312,227	$1,272,322
General service	1,014,124	964,853	921,337
Industrial			
Textile	487,576	482,172	475,191
Other	726,399	696,413	668,765
Other energy and wholesale (c)(e)	476,862	460,849	441,777
Other electric revenues	152,742	44,970	37,568
Total electric revenues (d)	$4,281,876	$3,961,484	$3,816,960
NUMBER OF CUSTOMERS – END OF YEAR			
Residential	1,460,876	1,439,845	1,415,605
General service (f)	232,272	227,675	222,917
Industrial			
Textile	1,396	1,390	1,385
Other	7,338	7,314	7,255
Other energy and wholesale (c)	7,957	7,773	7,605
Total customers	1,709,839	1,683,997	1,654,767
RESIDENTIAL CUSTOMER STATISTICS			
Average number for year	1,455,609	1,431,403	1,409,775
Average annual use – KWH	13,372	12,427	12,710
Average annual billing	$ 978.40	$ 916.74	$ 902.50
AVERAGE ANNUAL BILLED REVENUE PER KWH			
Residential	7.32(cents)	7.38(cents)	7.10(cents)
General service	6.00	6.10	5.91
Industrial	4.31	4.36	4.35

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Other energy and wholesale (c)(e)	4.21	4.45	4.36

(TABLE CONTINUED)

	YEAR ENDED DECEMBER 31 1990	1989
SOURCES OF ELECTRIC ENERGY		
Millions of kilowatt-hours:		
Generated -- net output:		
Coal	27,262	26,175
Nuclear (a)	44,649	47,773
Hydro (b)	1,879	1,520
Oil and gas	53	27
Total generation	73,843	75,495
Purchased power and net interchange (c)	1,531	1,158
Total output	75,374	76,653
Less: Other Catawba Joint Owners' share	11,735	12,566
Plus: Purchases from Other Catawba Joint Owners	8,658	9,809
Total sources of energy	72,297	73,896
Line loss and company usage	(4,222)	(4,522)
Total kilowatt-hour sales (d)	68,075	69,374
AVERAGE COST PER TON OF COAL BURNED	$ 45.49	$ 45.13
ELECTRIC ENERGY SALES		
Millions of kilowatt-hours:		
Residential	17,221	16,895
General service	15,032	14,206
Industrial		
Textile	11,130	11,443
Other	14,764	14,491
Other energy and wholesale (c)(e)	10,468	11,969
Total kilowatt-hour sales billed	68,615	69,004

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Unbilled kilowatt-hour sales	(540)	370
Total kilowatt-hour sales (d)	68,075	69,374
ELECTRIC REVENUE		
Thousands of dollars:		
Residential	$1,216,945	$1,198,705
General service	886,480	851,422
Industrial		
Textile	476,493	493,933
Other	654,551	653,830
Other energy and wholesale (c)(e)	391,803	449,545
Other electric revenues	78,859	45,520
Total electric revenues (d)	$3,705,131	$3,692,955
NUMBER OF CUSTOMERS – END OF YEAR		
Residential	1,391,336	1,362,118
General service (f)	224,642	216,960
Industrial		
Textile	1,398	1,408
Other	7,325	7,310
Other energy and wholesale (c)	7,405	7,249
Total customers	1,632,106	1,595,045
RESIDENTIAL CUSTOMER STATISTICS		
Average number for year	1,383,799	1,356,088
Average annual use – KWH	12,444	12,459
Average annual billing	$ 879.42	$ 883.94
AVERAGE ANNUAL BILLED REVENUE PER KWH		
Residential	7.07(cents)	7.09(cents)
General service	5.90	5.99
Industrial	4.37	4.43
Other energy and wholesale (c)(e)	3.74	3.76

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(a) Includes 100% of Catawba generation.

(b) 1991 includes KWH of the Bad Creek Hydroelectric Station prior to commercial operation.

(c) Kilowatt-hour sales, Electric revenues and Net interchange and purchased power for the years 1989 and 1990 include a reclassification for certain power transactions previously classified as Net interchange and purchased power prior to a 1990 FERC order.

(d) Does not reflect operating statistics, kilowatt-hour sales and revenues of Nantahala Power and Light Company.

(e) Includes sales to Nantahala Power and Light Company.

(f) 1991 restated to eliminate certain duplicate customers.

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EXECUTIVE OFFICERS OF THE COMPANY

NAME	POSITION
William S. Lee**	Chairman of the Board, President and Chief Executive Officer
William H. Grigg**	Vice Chairman of the Board
William A. Coley**	Executive Vice President, Customer Group
Steve C. Griffith, Jr.**	Executive Vice President and General Counsel
Richard B. Priory**	Executive Vice President, Power Generation Group
Richard J. Osborne	Vice President and Chief Financial Officer
David L. Hauser	Controller (Chief Accounting Officer)

OTHER OFFICERS

Donald H. Denton, Jr.	Senior Vice President, Chief Planning Officer
Michael S. Tuckman	Senior Vice President, Nuclear Generation Department
James R. Bavis	Vice President, Human Resources
Sue A. Becht	Treasurer
Sharon A. Decker	Vice President, Customer Services
Excell O. Ferrell, III	Vice President, Northern Region
William L. Foust	President, Duke Merchandising
Ronald L. Gibson	Vice President, Marketing and Customer Planning
James E. Grogan	Vice President, Generation Services Department
James W. Hampton	Vice President, Oconee Nuclear Site
Donald E. Hatley	Vice President, Public Affairs

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Jim R. Hicks	Vice President, Information Technology Services
J. William Hillhouse, Jr.	Vice President, Charlotte Area
James D. Hinton	Vice President, Power Delivery
John P. Holland	Vice President, Winston-Salem Area
F. Alfred Jenkins	Vice President, Hickory Area
Robert S. Lilien	Vice President and Tax Counsel
John F. Lomax	Vice President, Southern Region
David H. Maher	Vice President, Greensboro Area
Maurice D. McIntosh	Vice President, Fossil & Hydro Generation Department
Ted C. McMeekin	Vice President, McGuire Nuclear Site
Barbara B. Orr	Vice President, Greenville Area
David L. Rehn	Vice President, Catawba Nuclear Site
William F. Reinke	Vice President, System Planning & Operating
William T. Robertson, Jr.	Vice President, Procurement, Services and Materials
Christopher C. Rolfe	Vice President, Corporate Performance
Ellen T. Ruff	Secretary and Deputy General Counsel
Ruth G. Shaw	Vice President, Corporate Communications
William R. Stimart	Vice President, Rates and Regulatory Affairs
Fred E. West, Jr.	Vice President, Central Region
Virginia M. Britton	Assistant Controller
Carolyn R. Duncan	Assistant Secretary
S. L. Love	Assistant Treasurer
Phyllis T. Simpson	Assistant Secretary

(TABLE CONTINUED)

NAME	SERVICE IN SUCH CAPACITY SINCE	AGE*
William S. Lee**	1982	64
William H. Grigg**	1991	61
William A. Coley**	1991	50
Steve C. Griffith, Jr.**	1991	60
Richard B. Priory**	1991	47
Richard J. Osborne	1991	42
David L. Hauser	1987	42

OTHER OFFICERS
Donald H. Denton, Jr.
Michael S. Tuckman

James R. Bavis

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Sue A. Becht
Sharon A. Decker
Excell O. Ferrell, III
William L. Foust
Ronald L. Gibson
James E. Grogan
James W. Hampton
Donald E. Hatley
Jim R. Hicks
J. William
Hillhouse, Jr.
James D. Hinton
John P. Holland
F. Alfred Jenkins
Robert S. Lilien
John F. Lomax
David H. Maner
Maurice D. McIntosh
Ted C. McMeekin
Barbara B. Orr
David L. Rehn
William F. Reinke
William T.
Robertson, Jr.

Christopher C. Rolfe
Ellen T. Ruff
Ruth G. Shaw
William R. Stimart
Fred E. West, Jr.
Virginia M. Britton
Carolyn R. Duncan
S. L. Love
Phyllis T. Simpson

* As of February 1, 1994.

** Member of the Management Committee.

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Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers

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nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

All of the above executive officers have held responsible positions with the Company for the past five years.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

ITEM 2. PROPERTIES.

The map on page 12 shows the location of the Company's service area and generating stations.

Reference is made to Schedule V --Property, Plant and Equipment for information concerning the Company's investment in utility plant. Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see "Business --Energy Management and Future Power Needs".

ITEM 3. LEGAL PROCEEDINGS.

Reference is made to "Notes to Consolidated Financial Statements, Note 13 --Commitments and Contingencies", "Business --Regulation --NUCLEAR FACILITIES" and "Subsequent Events".

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ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

No matters were submitted to a vote of the Company's security holders during the last quarter of 1993.

PART II.

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

The Common Stock of the Company is traded on the New York Stock Exchange. At December 31, 1993, there were approximately 127,688 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by the New York Stock Exchange Composite Transactions:

		STOCK PRICE RANGE	
COMMON STOCK	DIVIDENDS PER SHARE	HIGH	LOW
1993 by Quarter			
Fourth	$0.47	$ 44	$ 39
Third	0.47	44 7/8	39 7/8
Second	0.45	41 3/8	37 1/8
First	0.45	39 7/8	35 3/8
1992 by Quarter			
Fourth	$0.45	$ 37 1/2	$ 34 5/8
Third	0.45	36 1/2	34 1/8

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Second	0.43	34 5/8	32
First	0.43	35	31 3/8

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ITEM 6.

SELECTED FINANCIAL DATA

	1993	1992
CONDENSED CONSOLIDATED STATEMENTS OF INCOME		
(thousands)		
Electric revenues (a)	$ 4,281,876	$ 3,961,484
Electric expenses (a)	3,467,811	3,236,789
Electric operating income	814,065	724,695
Other income	71,269	85,007
Income before interest deductions	885,334	809,702
Interest deductions	258,919	301,619
Net income	626,415	508,083
Dividends on preferred and preference stock	52,429	56,407
Earnings for common stock	$ 573,986	$ 451,676
COMMON STOCK DATA (b)		
Shares of common stock		
– year-end (thousands)	204,859	204,859
– average (thousands)	204,859	204,819
Per share of common stock		
Earnings	$ 2.80	$ 2.21
Dividends	$ 1.84	$ 1.76
Book value – year-end	$ 21.17	$ 20.26
Market price – high-low	$44 7/8-35 3/8	$37 1/2-31 3/8
– year-end	$ 42 3/8	$ 36 1/8
BALANCE SHEET DATA (thousands)		
Total assets	$12,193,107	$10,950,387
Long-term debt	$ 3,285,397	$ 3,288,111
Preferred stock with sinking fund requirements	$ 281,000	$ 279,519

CONDENSED CONSOLIDATED STATEMENTS OF INCOME	
(thousands)	
Electric revenues (a)	$ 3,692,955
Electric expenses (a)	2,988,355
Electric operating income	704,600
Other income	101,826

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Income before interest deductions	806,426
Interest deductions	234,815
Net income	571,611
Dividends on preferred and preference stock	52,477
Earnings for common stock	$ 519,134
COMMON STOCK DATA (b)	
Shares of common stock	
– year-end (thousands)	202,563
– average (thousands)	202,554
Per share of common stock	
Earnings	$ 2.56
Dividends	$ 1.52
Book value – year-end	$ 18.05
Market price – high-low	$ 28 1/4-21 3/8
– year-end	$ 28 1/16
BALANCE SHEET DATA (thousands)	
Total assets	$ 9,542,398
Long-term debt	$ 2,822,442
Preferred stock with sinking fund requirements	$ 247,825

(TABLE CONTINUED)

	1991	1990
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (thousands)		
Electric revenues (a)	$ 3,816,960	$ 3,705,131
Electric expenses (a)	3,110,137	3,062,348
Electric operating income	706,823	642,783
Other income	150,905	146,740
Income before interest deductions	857,728	789,523
Interest deductions	274,105	251,335
Net income	583,623	538,188
Dividends on preferred and preference stock	54,683	52,616
Earnings for common stock	$ 528,940	$ 485,572
COMMON STOCK DATA (b)		
Shares of common stock		
– year-end (thousands)	204,699	202,584
– average (thousands)	203,431	202,570
Per share of common stock		
Earnings	$ 2.60	$ 2.40
Dividends	$ 1.68	$ 1.60
Book value – year-end	$ 19.86	$ 18.84
Market price – high-low	$ 35-26 3/4	$32 3/8-25 1/2
– year-end	$ 35	$ 30 5/8
BALANCE SHEET DATA (thousands)		
Total assets	$10,470,615	$10,083,507
Long-term debt	$ 3,159,575	$ 3,102,746

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Preferred stock with sinking fund requirements	$ 228,650	$ 239,800
CONDENSED CONSOLIDATED STATEMENTS OF INCOME		
(thousands)		
Electric revenues (a)		
Electric expenses (a)		
Electric operating income		
Other income		
Income before interest deductions		
Interest deductions		
Net income		
Dividends on preferred and preference stock		
Earnings for common stock		
COMMON STOCK DATA (b)		
Shares of common stock		
-- year-end (thousands)		
-- average (thousands)		
Per share of common stock		
Earnings		
Dividends		
Book value -- year-end		
Market price -- high-low		
-- year-end		
BALANCE SHEET DATA (thousands)		
Total assets		
Long-term debt		
Preferred stock with sinking fund requirements		

(a) Electric revenues, Electric expenses, Kilowatt-hour sales and Net interchange and purchased power for the years 1989 and 1990 include a reclassification for certain power transactions previously classified as Net interchange and purchased power prior to a 1990 FERC order.

(b) All common stock data reflects the two-for-one split of common stock on September 28, 1990.

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Item 7. Management's Discussion and Analysis of Results of Operations and Financial Condition

Results of Operations

Earnings and Dividends

Earnings per share increased 27 percent from $2.21 in 1992 to $2.80 in 1993. The increase was primarily due to higher kilowatt-hour sales and a one-time charge taken in 1992 related to a rate refund to North Carolina retail customers of $ .32 per share. (For additional information on the refund, see Liquidity and Resources "Rate Matters," page 18.) The increase was partially offset by higher operating and maintenance expenses, additional charitable contributions to the Duke Power Company Foundation and an increase in the federal income tax rate caused by the Omnibus Budget Reconciliation Act of 1993. Higher general taxes also decreased earnings.

Earnings per share increased from $2.60 in 1991 to $2.80 in 1993, indicating an average annual growth rate of 4 percent. Total Company earned return on average common equity was 13.6 percent in 1993 compared to 11.1 percent in 1992 and 13.5 percent in 1991.

The Company continued its practice of increasing the common stock dividend annually. Common dividends per share increased from $1.68 in 1991 to $1.84 in 1993, rising at an average annual rate of 5 percent. Indicated annual dividends per share increased to $1.88.

Revenue and Sales

Revenues increased at an average annual rate of 6 percent from 1991 to 1993, primarily because of increased overall kilowatt-hour sales and the November 1991 rate increases.

Kilowatt-hour sales for 1993 increased 7 percent compared to 1992. Sales to residential customers increased by 9 percent reflecting colder winter weather and a hotter-than-normal summer. General service customer kilowatt-hour sales increased by 7 percent as a result of both continued economic growth and weather trends cited above. Sales to other-industrial customers and textile customers increased by 6 percent and 2 percent, respectively, as a result of the continued economic growth in the Company's service area.

Operating Expenses

From 1992 to 1993, non-fuel operating and maintenance expenses rose 4

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percent. Administrative and general expenses increased partly because of increased pension expenses to reflect more conservative investment return assumptions and one-time costs associated with a voluntary separation option offered during the first quarter of 1993. A winter storm during the first quarter of 1993 also increased non-fuel operating and maintenance expenses. These increases from 1992 to 1993 were partially offset by lower nuclear and fossil maintenance expenses resulting from lower outage costs.

Non-fuel operating and maintenance expenses increased at an average annual rate of 5 percent from 1991 to 1993. Administrative and general expenses increased over this period because of the implementation of a new accounting standard in January 1992 that reflects accrual basis accounting for certain postretirement health care and life insurance benefits, in addition to the reasons cited in the preceding paragraph. Operating and maintenance expenses for fossil and hydro plants also increased from 1991 to 1993. Fossil increases were caused by bringing refurbished units back on-line, and hydro increases were the result of the completion of the Bad Creek Hydroelectric Station in late 1991.

Net interchange and purchased power decreased at an average annual rate of 1 percent from 1991 to 1993. A slight decline in the amount of purchased power from the other Catawba joint owners as recognized on the income statement was substantially offset by increased purchases from other utilities. (For additional information on the Catawba purchase power agreements, see Note 3 to the Consolidated Financial Statements.)

Fuel expense increased at an average annual rate of 6 percent from 1991 to 1993. The increase was due primarily to higher system production requirements that were satisfied by increased fossil generation. A continued decline of fuel prices over this period helped to offset the overall increase in fuel expenses.

From 1991 to 1993, depreciation and amortization expense increased at an average annual rate of 6 percent primarily because of the completion of the Bad Creek Hydroelectric Station in 1991 and added investment in distribution property.

Other Income and Interest Deductions

Allowance for funds used during construction (AFUDC) represented 5 percent of earnings for common stock in 1993 compared to 13 percent in 1991. The decrease is primarily the result of the completion of the Bad Creek Hydroelectric Station in 1991. AFUDC is expected to represent less than 10 percent of total earnings during the next three years.

The carrying charge, net of associated taxes, on the purchased capacity levelization deferral related to the joint ownership of the Catawba

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Nuclear Station represented 6 percent of total earnings in 1993, compared to 6 percent in 1992 and 5 percent in 1991. This carrying charge and the related tax benefits are included in Other, net and Income taxes –other, net, respectively. The growth in this carrying charge is due to the increasing cumulative impact of the Company's funding of purchased power costs which current rates are expected to collect in future periods. The Company recovers the accumulated balance, including the carrying charge, when the declining purchased capacity payments drop below the levelized revenues. (For additional information on purchased capacity levelization, see Capital Needs "Purchased Capacity Levelization," page 19.)

Interest on long-term debt decreased at an average annual rate of 3 percent from 1991 to 1993. The decrease is due to the Company's refinancing of higher cost debt beginning in late 1991 and continuing throughout 1993. From 1992 to 1993, Other interest decreased as a result of the one-time impact in 1992 of approximately $27 million in interest paid to North Carolina retail customers due to a rate refund.

Income provided by diversified activities and the Company's subsidiaries was $22.0 million in 1993 compared to $25.7 million in 1992 and $23.6 million in 1991. The activities of Crescent Resources, Inc., the Company's real estate development and forest management subsidiary, generated the majority of subsidiary and non-electric earnings. Other components include subsidiary investment income, fees for engineering services, construction and operation of generation and transmission

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facilities outside the Company's service area, water operations and merchandising.

Liquidity and Resources

Rate Matters

During 1991, the Company filed in both the North Carolina and South Carolina retail jurisdictions its only requests for general rate increases since 1986. The rate increases were primarily needed to recover costs associated with the construction of the Bad Creek Hydroelectric Station. In North Carolina, the Company requested a 9.22 percent rate increase and was granted a 4.15 percent increase, which resulted in additional annual revenues of $100.1 million. In South Carolina, a 7.29 percent increase was requested and a 3.0 percent rate

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increase was granted, resulting in additional annual revenues of $30.2 million.

Also in 1991, the Company filed a request for a wholesale rate increase with the Federal Energy Regulatory Commission (FERC). A negotiated settlement between the Company and the wholesale customers was approved by the FERC on March 31, 1992. The approved agreement, effective April 1, 1992, provided for a 3.3 percent rate increase, resulting in $2.1 million in additional annual revenues.

The North Carolina Supreme Court on April 22, 1992, remanded for the second time the Company's 1986 rate order to the North Carolina Utilities Commission (NCUC). In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return on common equity of 13.2 percent authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order dated October 26, 1992, authorizing a 12.8 percent return on common equity for the period October 31, 1986, through November 11, 1991. This order resulted in a 1992 refund to North Carolina retail customers of approximately $95 million, including interest. .

The Company has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

The other joint owners of the Catawba Nuclear Station and the Company are involved in various proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding is that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.) The Company and two of the four joint owners have entered into a proposed settlement agreement which, if approved by the regulators, will resolve all issues in contention in such proceedings between the Company and these owners. The Company recorded a liability as an increase to Other current liabilities on its Consolidated Balance Sheets of approximately $105 million in 1993 to reflect this proposed settlement. In addition, future estimated obligations in connection with the settlement are reflected in estimates of purchased capacity obligations in Note 3. As the Company expects the costs associated with this settlement will be recovered as part of the purchased capacity levelization, the Company has included approximately $105 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the

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Company believes the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Although the two other Catawba joint owners, who are not parties to the above settlement, have not fully quantified the dollars associated with their claims in the presently outstanding proceedings, information associated with these proceedings indicates that the amount in contention could be as high as $110 million, through December 31, 1993. Arbitration hearings were held in 1992 involving substantially all the disputed amounts, and a decision interpreting the language of the agreements on certain of these matters was issued on October 1, 1993. Further proceedings will be required to determine the amounts associated with this decision as it relates to these owners, some of which may involve refunds. However, the Company expects the costs associated with this decision will be included in and recovered as part of the purchased capacity levelization consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

Cash From Operations

In 1993, net cash provided by operating activities accounted for 46 percent of total cash from operating, financing and investing activities compared to 50 percent in 1992 and 77 percent in 1991. For 1993 and 1992, essentially all the Company's capital needs, exclusive of refinancing activities, were met by cash generated from operations.

Financing and Investing Activities

The Company's capital structure, including subsidiary capitalization, at year-end 1993 was 52 percent common equity, 39 percent long-term debt and 9 percent preferred stock. This structure is consistent with the Company's target to maintain an "AA" credit rating. As of December 31, 1993, the Company's bonds were rated "AA" by Fitch Investors Service, "Aa2" by Moody's Investors Service, and "AA-" by Standard & Poor's Ratings Group and Duff & Phelps.

As a result of favorable market conditions, the Company continued refinancing activities to retire higher cost debt and preferred stock.

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During 1993, the Company obtained proceeds from the issuance of $1.5 billion in long-term debt and $220 million in preferred stock, most of which were used to retire $1.4 billion of long-term debt and $216 million of preferred stock.

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In 1992, the Company issued $940 million in long-term debt. Most of these proceeds, combined with the proceeds from bonds issued in late 1991, were used to redeem $884 million of long-term debt. During 1992, the Company also issued $284 million of preferred stock, most of which was used to redeem $229 million of preferred stock.

Also on April 6, 1992, the Company redeemed all outstanding shares of the Cumulative Preference Stock 6 3/4 percent Convertible Series AA at its par value of $100 per share.

The Company's embedded cost of long-term debt for 1993 decreased to 8.01 percent compared to 8.39 percent in 1992 and 8.72 percent in 1991. The embedded cost of preferred stock declined to 6.76 percent in 1993 from 7.05 percent in 1992 and 7.48 percent in 1991. These decreases are primarily the result of the Company's refinancing activities. Downward trends in embedded costs may level off because of fewer refinancing opportunities.

Fixed Charges Coverage

Fixed charges coverage using the SEC method increased to 4.68 times for 1993 compared to 3.48 and 3.85 times, respectively, in 1992 and 1991. Fixed charges coverage, excluding AFUDC and the return on purchased capacity levelization, was 4.40 times in 1993 compared to 3.27 in 1992 and 3.46 in 1991 and the Company goal of 3.5 times. In 1992, the coverage under both methods was lower because of the impact of the rate refund.

Capital Needs

Property Additions and Retirements

Additions to property and nuclear fuel of $676 million and retirements of $312 million resulted in an increase in gross plant of $364 million in 1993.

Since January 1, 1991, additions to property and nuclear fuel of $2.1 billion and retirements of $780 million have resulted in an increase in gross plant of $1.3 billion.

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Construction Expenditures

Plant construction costs for generating facilities, including AFUDC, decreased from $232 million in 1991 to $182 million in 1993. Completion of the Bad Creek Hydroelectric Station in 1991 was a significant part of the decrease. Construction costs for distribution plant, including AFUDC, decreased from $275 million in 1991 to $240 million in 1993.

Projected construction and nuclear fuel costs, both including AFUDC, are $2.3 billion and $394 million, respectively, for 1994 through 1996. Total projected construction costs include expenditures for the construction of the Lincoln Combustion Turbine Station and replacement of certain steam generators at the McGuire Nuclear Station and the Catawba Nuclear Station. (For additional information on steam generator replacement, see Current Issues "Stress Corrosion Cracking," page 21.) For 1994 through 1996, the Company anticipates funding its projected construction and nuclear fuel costs through the internal generation of funds and, to a lesser extent, through the issuance of securities, primarily First and Refunding Mortgage Bonds.

Purchased Capacity Levelization

The rates established in the Company's retail jurisdictions permit the Company to recover its investment in both units of the Catawba Nuclear Station and the costs associated with contractual purchases of capacity from the other Catawba joint owners. The contracts relating to the sales of portions of the station obligate the Company to purchase a declining amount of capacity from the other joint owners. In the North Carolina retail jurisdiction, regulatory treatment of these contracts provides revenue for recovery of the capital costs and the fixed operating and maintenance costs of purchased capacity on a levelized basis. In the South Carolina retail jurisdiction, revenues are provided for the recovery of the capital costs of purchased capacity on a levelized basis, while current rates include recovery of fixed operating and maintenance expenses.

These rate treatments require the Company to fund portions of the purchased power payment until these costs, including carrying charges, are recovered at a later date. The Company recovers the accumulated costs and carrying charges when the declining purchased capacity payments drop below the levelized revenues. In the North Carolina and wholesale jurisdictions, purchased capacity payments continue to exceed levelized revenues. In the South Carolina jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments. Jurisdictional levelizations are intended to recover total costs, including allowed returns, and are subject to adjustments, including final true-ups.

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Meeting Future Power Needs

The Company's strategy for meeting customers' present and future energy needs is composed of three components: supply-side resources, demand-side resources and purchased power resources. To assist in determining the optimal combination of these three resources, the Company uses its integrated resource planning process. The goal is to provide adequate and reliable electricity in an environmentally responsible manner through cost-effective power management.

The Company is building a combustion turbine facility in Lincoln County, North Carolina. The Lincoln Combustion Turbine Station will consist of 16 combustion turbines with a total generating capacity of 1,184 megawatts. The estimated total cost of the project is approximately $500 million. Current plans are for ten units to begin commercial operation by the end of 1995 and the remaining six to begin commercial operation before the end of 1996. The Lincoln facility will provide capacity at periods of peak demand.

Demand-side management programs are a part of meeting the Company's future power needs. These programs benefit the Company and its customers by providing for load control through interruptible control features, shifting usage to off-peak periods, increasing usage during off-peak periods, and by promoting energy efficiency. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help to reduce their electric bills. Demand-side management programs such as Industrial Interruptible Service and Residential Load Control can be used to manage capacity availability problems. Energy-efficiency programs such as high-efficiency chillers, high-efficiency heat pumps and high-efficiency air conditioners are other examples of current demand-side management programs. The November 1991 rate orders of the NCUC and The Public Service Commission of South Carolina (PSCSC) provided for recovery

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in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. As additional demand-side costs are incurred, the Company ultimately expects recovery of associated costs, which are currently being deferred, through rates. The annual costs deferred, including the return, were approximately $26

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million in 1993 and $18 million in 1992.

The purchase of capacity and energy is also an integral part of meeting future power needs. The Company currently has under contract 500 megawatts of capacity from other generators of electricity.

Current Issues

While the Company improved its financial performance in 1993 compared to 1992, the ability to maintain and improve its current level of earnings will depend on several factors. Future trends in the Company's earnings will depend on the continued economic growth in the Piedmont Carolinas, the Company's ability to contain costs, its ability to maintain competitive prices, the outcome of various legislative and regulatory actions and the success of the Company's diversified activities.

Resource Optimization. The Company has been engaged in a concentrated effort to more efficiently and effectively use its resources through better work practices. During the first quarter of 1993, the Company offered a Limited Period Separation Opportunity program (LPSO) which gave employees the option of leaving the Company for a lump sum severance payment and, for qualifying employees, enhanced retirement benefits. Implementing programs such as LPSO and other efficiency practices has resulted in a continued workforce reduction and in streamlined workflows. The number of full-time employees has decreased from 19,945 at year-end 1990 to 18,274 at year-end 1993. Included in these amounts are 496 and 789 employees of subsidiaries and affiliates for 1990 and 1993, respectively.

Income Tax Accounting Change. In January 1993, the Company implemented a standard as required by the Financial Accounting Standards Board (FASB) that requires a liability approach for financial accounting and reporting for income taxes. While classification of certain items on the Consolidated Balance Sheets has changed, principally because certain items previously reported net of tax are now being reported on a gross basis, there is no material effect on the Company's results of operations.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $955 million stated in 1990 dollars. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are liable for providing decommissioning related to their ownership interests in the station. Both the NCUC and the PSCSC have granted the Company recovery of the estimated site-specific decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume that units will be

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decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 - 2013, Oconee 3 - 2014; McGuire 1 - 2021, McGuire 2 - 2023; and Catawba 1 - 2024, Catawba 2 - 2026.

The Nuclear Regulatory Commission (NRC) issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1993, the Company expensed approximately $52.5 million which was contributed to the external funds and accrued an additional $5.0 million to the internal reserve. The balance of the external funds as of December 31, 1993, was $118.5 million. The balance of the internal reserve as of December 31, 1993, was $200.0 million and is reflected in Accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the estimated site-specific decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 4.5 percent to 5.5 percent, are currently sufficient to provide for the cost of decommissioning based on the Company's current decommissioning schedule.

Environmental Update. The Company is subject to federal, state and local regulations with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. The Company was an operator of manufactured gas plants prior to the early 1950s. The Company is entering into a cooperative effort with the State of North Carolina and other owners of certain former manufactured gas plant sites to investigate and, where necessary, remediate these contaminated sites. The State of South Carolina has expressed interest in entering into a similar arrangement. The Company is considered by regulators to be a potentially responsible party and may be subject to liability at two federal Superfund sites and two comparable state sites. While the cost of remediation of these sites may be substantial, the Company will share in any liability associated with remediation of contamination at such sites with other potentially responsible parties. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

The Clean Air Act Amendments of 1990. The Clean Air Act Amendments of 1990 require a two-phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national objective of clean air in the most cost-effective manner and has already reduced emissions through the use of low-sulfur coal in its fossil plants, through efficient operations

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and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. The Company is currently developing a detailed

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compliance plan for Phase II requirements which must be filed with the Environmental Protection Agency (EPA) by 1996. A preliminary strategy, which allows for varying options, indicates that one-time costs associated with bringing the Company into compliance with the Act could be as high as $1 billion, and that approximately $75 million in additional annual operating and maintenance expenses will be incurred as well. These one-time costs could be less depending on favorable developments in the emissions allowance market, future regulatory and legislative actions, and advances in clean air technology. All options within the preliminary strategy allow for full compliance of Phase II requirements by the year 2000.

Stress Corrosion Cracking (SCC). Stress corrosion cracking has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. The Company is of the opinion that the SCC is caused by the defective design, workmanship and materials used by the manufacturer of the steam generators. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC will be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the Catawba and McGuire steam generators still exists. The Company has begun planning for the replacement of steam generators and has set the following schedule to begin the process: McGuire Unit 1 - 1995, Catawba Unit 1 - 1996, McGuire Unit 2 - 1997. The Catawba Unit 2 steam generators have not been scheduled for replacement. The order of replacement is subject to change based on performance of the existing steam generators and on the overall performance of the three units. The Company has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $170 million, excluding the cost of replacement power and without consideration of reimbursement of applicable costs by the other joint owners of Catawba Unit 1. Stress corrosion problems are excluded under the nuclear insurance policies.

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The Company in connection with its McGuire and Catawba stations and on behalf of the other joint owners of the Catawba Station--North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation, Piedmont Municipal Power Agency and Saluda River Electric Cooperative, Inc.--commenced a legal action on March 22, 1990. This action alleges that Westinghouse Electric Corporation (Westinghouse), the supplier of the steam generators, knew, or recklessly disregarded information in its possession, that the steam generators supplied to McGuire and Catawba stations would be susceptible to SCC and that Westinghouse deliberately concealed such information from the Company. The Company is seeking a judgment against Westinghouse for damages of approximately $600 million, including the cost of necessary remedial measures, the cost of replacement steam generators and payment for replacement power during the outages to accomplish the replacement. In addition to these damages, the Company is seeking punitive or treble damages and attorneys' fees. A trial date has been set for March 14, 1994.

Competition. The Energy Policy Act of 1992 has far-reaching implications for the Company by moving utilities toward a more competitive environment. The Act reformed certain provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and removed certain regulatory barriers. For example, the Act allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to registration under PUHCA as an electric utility holding company. The Act requires transmission of power for third parties to wholesale customers, provided the reliability of service to the utility's local customer base is protected and the local customer base does not subsidize the third-party service. Although the Act does not require transmission access to retail customers, states can authorize such transmission access to and for retail electric customers.

The electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry, for any reason, including competitive pressure on the price of electricity, utilities might be forced to reduce their assets to reflect their market basis if such basis is less than cost. Discontinuance of cost-based regulation could also require some utilities to write off their regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company is continuing to position itself to effectively meet these challenges by maintaining prices that are regionally and nationally competitive.

Subsidiary Activities. A major part of the future growth in the electric power market is anticipated to be outside the traditional

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regulated framework and, to a large extent, outside the United States. The Company, through its subsidiaries, is participating in these international opportunities and continues participating in domestic opportunities to provide additional value to its shareholders. Internationally, the Company is seeking opportunities to provide engineering consulting services, construction, operation and maintenance of generation facilities, and ownership of transmission and generation facilities. Although these opportunities are concentrated in areas that utilize the Company's expertise, they present different and greater risks than does the Company's core business. The Company considers only opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. At December 31, 1993, the Company had equity investments of $84.5 million in international transmission and generation facilities and $17.1 million in electric assets within the United States, but outside its current service area. The Company is actively pursuing additional international and domestic opportunities to capitalize on the future potential growth of this market.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

DUKE POWER COMPANY
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CONSOLIDATED STATEMENTS OF INCOME
Dollars in Thousands

	Year ended December 31, 1993	1992
ELECTRIC REVENUES (Notes 1 and 2)	$4,281,876	$3,961,484
ELECTRIC EXPENSES		
Operation		
Fuel used in electric generation (Note 1)	732,246	659,593
Net interchange and purchased power (Note 3)	535,033	540,840
Wages, benefits and materials	701,994	636,729
Maintenance of plant facilities	375,457	403,162
Depreciation and amortization (Note 1)	488,441	491,339
General taxes	231,680	215,493
Income taxes (Notes 1 and 4)	402,960	289,633
Total electric expenses	3,467,811	3,236,789
Electric operating income	814,065	724,695
OTHER INCOME (Notes 1, 4, 11 and 14)		
Allowance for equity funds used during construction	17,221	15,476
Other, net	61,769	83,216

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Income taxes -- other, net	(24,092)	(27,475)
Income taxes -- credit	16,371	13,790
Total other income	71,269	85,007
Income before interest deductions	885,334	809,702
INTEREST DEDUCTIONS		
Interest on long-term debt	256,347	265,646
Other interest	12,431	41,736
Allowance for borrowed funds used during construction (Notes 1 and 4)	(9,859)	(5,763)
Total interest deductions	258,919	301,619
NET INCOME	626,415	508,083
Dividends on preferred and preference stock	52,429	56,407
EARNINGS FOR COMMON STOCK	$ 573,986	$ 451,676
COMMON STOCK DATA (Note 6)		
Average shares outstanding (thousands)	204,859	204,819
Earnings per share	$2.80	$2.21
Dividends per share	$1.84	$1.76

(TABLE CONTINUED)

	Year ended December 31, 1991
ELECTRIC REVENUES (Notes 1 and 2)	$3,816,960
ELECTRIC EXPENSES	
Operation	
Fuel used in electric generation (Note 1)	657,725
Net interchange and purchased power (Note 3)	545,840
Wages, benefits and materials	622,121
Maintenance of plant facilities	354,679
Depreciation and amortization (Note 1)	431,624
General taxes	204,688
Income taxes (Notes 1 and 4)	293,460
Total electric expenses	3,110,137
Electric operating income	706,823
OTHER INCOME (Notes 1, 4, 11 and 14)	
Allowance for equity funds used during construction	50,704
Other, net	102,884
Income taxes -- other, net	(25,472)
Income taxes -- credit	22,789
Total other income	150,905
Income before interest deductions	857,728
INTEREST DEDUCTIONS	
Interest on long-term debt	274,662
Other interest	18,834
Allowance for borrowed funds used during construction (Notes 1 and 4)	(19,391)
Total interest deductions	274,105
NET INCOME	583,623
Dividends on preferred and preference stock	54,683
EARNINGS FOR COMMON STOCK	$ 528,940

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COMMON STOCK DATA (Note 6)	
Average shares outstanding (thousands)	203,431
Earnings per share	$2.60
Dividends per share	$1.68

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

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CONSOLIDATED STATEMENTS OF CASH FLOWS
Dollars in Thousands

	Year ended December 31,		
	1993	1992	1991
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 626,415	$ 508,083	$ 583,623
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash items			
Depreciation and amortization (Note 1)	657,068	660,896	619,823
Deferred income taxes and investment tax credit, net of amortization (Note 4)	56,315	44,518	27,456
Allowance for equity funds used during construction	(17,221)	(15,476)	(50,704)
Purchased capacity levelization (Note 3)	(20,049)	(66,511)	(70,605)
Other, net (Note 15)	36,864	(16,258)	(32,149)
(Increase) Decrease in			
Accounts receivable	(36,948)	14,255	(45,412)
Inventory	29,150	(9,383)	6,866
Prepayments	(452)	(939)	181
Increase (Decrease) in			
Accounts payable	(54,275)	69,739	44,265
Taxes accrued (Notes 1 and 4)	26,583	4,514	11,739
Interest accrued and other liabilities			

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(Notes 1, 9 and 13)	30,185	(22,825)	12,863
Total adjustments	707,220	662,530	524,323
Net cash provided by operating activities	1,333,635	1,170,613	1,107,946
CASH FLOWS FROM INVESTING ACTIVITIES			
Construction expenditures	(543,563)	(465,292)	(572,705)
Investment in nuclear fuel	(111,731)	(122,565)	(183,803)
External Funding for decommissioning (Note 16)	(52,524)	(61,246)	--
Pre-funded pension cost (Note 12)	(50,000)	--	--
Net change in investment securities and joint ventures (Notes 1, 11 and 15)	(12,379)	(96,475)	(35,807)
Net cash used in investing activities	(770,197)	(745,578)	(792,315)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of			
First and refunding mortgage bonds	1,395,682	926,650	414,297
Preferred stock	215,633	281,089	--
Pollution-control bonds	76,265	--	--
Short-term notes payable, net (Note 5)	(108,000)	40,000	(99,000)
Common stock	--	--	48,014
Payments for the redemption of			
First and refunding mortgage bonds	(1,399,336)	(1,013,218)	(279,970)
Preferred stock	(224,295)	(246,414)	(9,650)
Pollution-control bonds	(79,310)	--	--
Dividends paid	(427,868)	(417,443)	(381,589)
Other (Note 15)	(5,926)	3,313	(5,662)
Net cash used in financing activities	(557,155)	(426,023	(313,560)
Net increase (decrease) in cash	6,283	(988)	2,071
Cash at beginning of year	9,293	10,28	8,210
Cash at end of year	$ 15,576	$ 9,293	$ 10,281

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

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CONSOLIDATED BALANCE SHEETS

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ASSETS

	Dollars in Thousands December 31, 1993	1992
ELECTRIC PLANT (at original cost – s 1, 3, 9, 13, 15 and 16)		
Electric plant in service	$12,573,012	$12,193,888
Less accumulated depreciation and amortization	4,431,460	4,197,505
Electric plant in service, net	8,141,552	7,996,383
Nuclear fuel	705,994	718,420
Less accumulated amortization	405,910	425,088
Nuclear fuel, net	300,084	293,332
Construction work in progress (including nuclear fuel in process: 1993 – $113,904; 1992 – $148,945)	482,473	490,408
Total electric plant, net	8,924,109	8,780,123
OTHER PROPERTY AND INVESTMENTS		
Other property – at cost (less accumulated depreciation: 1993 – $90,191; 1992 – $83,108) (Note 15)	311,241	295,098
Investments in joint ventures (Notes 11 and 15)	101,612	31,268
Other investments, at cost or less	90,301	127,632
Nuclear decommissioning trust funds (Notes 10, 15 and 16)	118,456	61,812
Pre-funded pension cost (Note 12)	50,000	–
Total other property and investments	671,610	515,810
CURRENT ASSETS		
Cash (Notes 5 and 10)	15,576	9,293
Short-term investments (Note 10)	120,651	141,285
Receivables (less allowance for losses: 1993 – $6,392; 1992 – $5,207) (Note 1)	531,592	494,644
Inventory – at average cost		
Coal	69,155	101,550
Other	199,733	196,489
Prepayments	12,062	11,610
Total current assets	948,769	954,871
DEFERRED DEBITS (Notes 1, 3, 4, 13 and 15)		
Purchased capacity costs	768,099	378,095
Debt expense	197,963	115,436
Regulatory asset related to income taxes	486,440	–
Regulatory asset related to DOE assessment fee	116,731	101,785
Other	79,386	104,267
Total deferred debits	1,648,619	699,583
TOTAL ASSETS	$12,193,107	$10,950,387

CAPITALIZATION AND LIABILITIES

CAPITALIZATION (See Consolidated Statements of

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Capitalization)	$ 8,404,131	$ 8,218,257
CURRENT LIABILITIES		
Accounts payable	337,391	394,721
Taxes accrued (Note 1)	82,824	36,885
Interest accrued	68,868	68,078
Other (Note 13)	211,207	75,613
Total	700,290	575,297 s payable (Notes 5 and 10) 18,000 126,000
Current maturities of long-term debt and preferred stock (Notes 9 and 15)	91,898	9,434
Total current liabilities	810,188	710,731
ACCUMULATED DEFERRED INCOME TAXES (Notes 1 and 4)	2,207,708	1,369,677
DEFERRED CREDITS AND OTHER LIABILITIES		
Investment tax credit (Notes 1 and 4)	282,505	296,165
DOE assessment fee (Note 1)	116,731	101,785
Nuclear decommissioning costs externally funded (Notes 15 and 16)	118,456	61,812
Other	253,388	191,960
Total deferred credits and other liabilities	771,080	651,722
COMMITMENTS AND CONTINGENCIES (Note 13)		
TOTAL CAPITALIZATION AND LIABILITIES	$12,193,107	$10,950,387

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

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CONSOLIDATED STATEMENTS OF CAPITALIZATION AND RETAINED EARNINGS

Dollars in Thousands

	December 31	
	1993	1992
CAPITALIZATION		
COMMON STOCK EQUITY (Notes 6 and 7)		
Common stock, no par, 300,000,000 shares authorized; 204,859,339 shares outstanding for 1993 and 1992	$1,926,909	$1,926,909
Retained earnings	2,410,825	2,223,718
Total common stock equity	4,337,734	4,150,627

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PREFERRED AND PREFERENCE STOCK WITHOUT SINKING FUND REQUIREMENTS (Note 7)	500,000	500,000
PREFERRED STOCK WITH SINKING FUND REQUIREMENTS (Notes 8 and 10)	281,000	279,519
LONG-TERM DEBT (Notes 9, 10 and 15)		
Parent company long-term debt	3,199,032	3,202,437
Subsidiary long-term debt	86,365	85,674
Total consolidated long-term debt	3,285,397	3,288,111
TOTAL CAPITALIZATION	$8,404,131	$8,218,257

Dollars in Thousands
Year ended December 31,

	1993	1992	1991
RETAINED EARNINGS			
BALANCE -- Beginning of year	$2,223,718	$2,141,259	$1,953,779
ADD -- Net income	626,415	508,083	583,623
Total	2,850,133	2,649,342	2,537,402
DEDUCT			
Dividends			
Common stock	376,937	360,475	341,801
Preferred and preference stock	52,429	56,407	54,683
Capital stock transactions, net	9,942	8,742	(341)
Total deductions	439,308	425,624	396,143
BALANCE -- End of year	$2,410,825	$2,223,718	$2,141,259

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

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s To Consolidated Financial Statements

1. Summary of Significant Accounting Policies

A. Revenues

Revenues are recorded as service is rendered to customers. "Receivables" on the Consolidated Balance Sheets include $175,726,000 and $167,610,000 as of December 31, 1993 and 1992, respectively, for service that has been rendered but not yet billed to customers.

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B. Additions to Electric Plant

The Company capitalizes all construction-related direct labor and materials as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of money (allowance for funds used during construction). The cost of renewals and betterments of units of property is capitalized. The cost of repairs and replacements representing less than a unit of property is charged to electric expenses. The original cost of property retired, together with removal costs less salvage value, is charged to accumulated depreciation.

C. Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new facilities. AFUDC, a non-cash item, is recognized as a cost of "Construction work in progress" (CWIP), with offsetting credits to "Other income" and "Interest deductions." After construction is completed, the Company is permitted to recover these construction costs, including a fair return, through their inclusion in rate base and in the provision for depreciation.

The 1993 AFUDC rate of 9.29 percent reflects "Allowance for borrowed funds used during construction" calculated using a pre-tax cost of debt. The rates for 1992 and 1991 of 8.07 percent and 8.86 percent have been calculated using a net of tax cost of debt. Rates for all periods are compounded semiannually. The change in calculation from a net of income tax to a pre-tax basis is a result of the adoption of Statement of Financial Accounting Standards No. 109 (SFAS 109). (See 4.)

D. Depreciation and Amortization

Provisions for depreciation are recorded using the straight-line method. The year-end composite weighted-average depreciation rates were 3.47 percent for 1993 and 3.48 percent for 1992 and 1991. Effective with the implementation of new retail rates in November 1991, all coal-fired generating units are depreciated at a rate of 2.57 percent and all nuclear units are depreciated at a rate of 4.70 percent, of which 1.61 percent is for decommissioning. (See Note 16.)

Amortization of nuclear fuel is included in "Fuel used in electric generation" in the Consolidated Statements of Income. The amortization is recorded using the units-of-production method.

Under provisions of the Nuclear Waste Policy Act of 1982, the Company has entered into contracts with the Department of Energy (DOE) for the disposal of spent nuclear fuel. Payments made to the DOE for disposal costs are based on nuclear output and are included in "Fuel used in

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electric generation" in the Consolidated Statements of Income.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid $8,338,000 during 1993 related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of $116,731,000 in the Consolidated Balance Sheets.

E. Subsidiaries

The Company's consolidated financial statements reflect consolidation of all of its wholly-owned subsidiaries. Intercompany transactions have been eliminated in consolidation. (See Note 11 and "Subsidiary Highlights," page 41.)

F. Income Taxes

The Company implemented SFAS 109, "Accounting for Income Taxes," effective January 1, 1993. (See Note 4.)

The Company and its subsidiaries file a consolidated federal income tax return. Income taxes have been allocated to each company based on its separate company taxable income or loss.

Income taxes are allocated to non-electric operations under "Other income" and to electric operating expense. The "Income taxes - credit" classified under "Other income" results from tax deductions of interest costs relating primarily to deferred purchased capacity costs and CWIP.

Deferred income taxes have been provided for temporary differences between book and tax income, principally resulting from accelerated tax depreciation and levelization of purchased power costs. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

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G. Unamortized Debt Premium, Discount and Expense

Expenses incurred in connection with the issuance of presently outstanding long-term debt, and premiums and discounts relating to such debt, are being amortized over the terms of the respective issues. Also, any expenses or call premiums associated with refinancing higher-cost debt obligations are being amortized over the lives of the new issues of long-term debt.

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H. Fuel Cost Adjustment Procedures

Fuel costs are reviewed semiannually in the wholesale and South Carolina retail jurisdictions, with provisions for changing such costs in base rates. In the North Carolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings.

All jurisdictions allow the Company to adjust rates for past over-or under-recovery of fuel costs. Therefore, the Company reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

The North Carolina legislature ratified a bill in July 1987 assuring the legality of such adjustments in rates. In 1991, the statute was extended through June 30, 1997.

I. Consolidated Statements of Cash Flows

For purposes of the Consolidated Statements of Cash Flows, the Company's investments in highly liquid debt instruments, with an original maturity of three months or less, are included in cash flows from investing activities and thus are not considered cash equivalents.

Total income taxes paid were $352,697,000, $215,465,000 and $245,945,000 for years ended December 31, 1993, 1992 and 1991, respectively.

Interest paid, net of amount capitalized, was $244,829,000, $298,455,000 and $269,330,000 for the years ended December 31, 1993, 1992 and 1991, respectively.

2. Rate Matters

The North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSCSC) must approve rates for retail sales within their respective states. The Federal Energy Regulatory Commission (FERC) must approve the Company's rates for sales to wholesale customers. Sales to the other joint owners of the Catawba Nuclear Station, which represent a substantial majority of the Company's wholesale revenues, are set through contractual agreements. (See Note 3.)

During 1991, the Company filed in both the North Carolina and the South Carolina retail jurisdictions its only requests for general rate increases since 1986. The rate increase requested by the Company in North Carolina was 9.22 percent; a 4.15 percent increase was granted resulting in $100.1 million in additional annual revenues. In South

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Carolina, a rate increase of 7.29 percent was requested; a 3.0 percent increase was granted resulting in $30.2 million in additional annual revenues. These increases were requested primarily to recover costs associated with the Bad Creek Hydroelectric Station.

In 1991, the Company filed a request with the FERC seeking a 7.47 percent rate increase for its wholesale customers, who represent approximately 2 percent of the Company's total revenues. A negotiated settlement between the Company and the wholesale customers was approved by the FERC on March 31, 1992. The approved agreement, effective April 1, 1992, provided for a 3.3 percent rate increase, resulting in $2.1 million in additional annual revenues.

The North Carolina Supreme Court on April 22, 1992, remanded for the second time the Company's 1986 rate order to the NCUC. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return of 13.2 percent on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order dated October 26, 1992, authorizing a 12.8 percent return on common equity for the period October 31, 1986, through November 11, 1991, that resulted in a refund to North Carolina retail customers in 1992 of approximately $95 million, including interest.

The Company has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

3. Joint Ownership of Generating Facilities

The Company has sold interests in both units of the Catawba Nuclear Station. The other owners of portions of the Catawba Nuclear Station and supplemental information regarding their ownership are as follows:

Owner	Ownership Interest in the Station
North Carolina Municipal Power Agency Number 1 (NCMPA)	37.5%
North Carolina Electric Membership Corporation (NCEMC)	28.125%

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Piedmont Municipal Power Agency
(PMPA) 12.5%

Saluda River Electric Cooperative, Inc.
(Saluda River) 9.375%

Each participant has provided its own financing for its ownership interest in the plant.

The Company retains a 12.5 percent ownership interest in the Catawba Nuclear Station. As of December 31, 1993, $498,930,000 of Electric plant in service and Nuclear fuel

[HARDCOPY PAGE 29]

represents the Company's investment in Units 1 and 2. Accumulated depreciation and amortization of $152,698,000 associated with Catawba had been recorded as of year-end. The Company's share of operating costs of Catawba are included in the corresponding electric expenses in the Consolidated Statements of Income.

In connection with the joint ownership, the Company has entered into contractual agreements with the other joint owners to purchase declining percentages of the generating capacity and energy from the plant. These agreements were effective beginning with the commercial operation of each unit. Unit 1 and Unit 2 began commercial operation in June 1985 and in August 1986, respectively. Such agreements were established for 15 years for NCMPA and PMPA and 10 years for NCEMC and Saluda River.

Energy cost payments are based on variable operating costs, a function of the generation output. Capacity payments are based on the fixed costs of the plant. The estimated purchased capacity obligations through 1998 are $392,000,000 for 1994, $293,000,000 for 1995, $55,000,000 for 1996, $44,000,000 for 1997 and $32,000,000 for 1998. Payment obligations include the terms of a proposed settlement agreement between the Company and two of the four joint owners of the Catawba Nuclear Station which was executed in January 1994 and is subject to regulatory approval. (See Note 13.)

Effective in its November 1991 rate order, the North Carolina Utilities Commission (NCUC) reaffirmed the Company's recovery, on a levelized basis, of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners. The new NCUC rate order changed the levelized basis to a 15-year period ending 2001 for all of the other joint owners compared to the previous 15-year levelization period for NCMPA and PMPA and 10-year levelization period for NCEMC and Saluda River. The Public Service Commission of South Carolina (PSCSC), in its November 1991 rate order, reaffirmed the

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Company's recovery on a levelized basis of the capital costs of capacity purchased from the other joint owners. The new PSCSC rate order retained the levelized basis of a 7 1/2-year period for PMPA and NCMPA; for NCEMC and Saluda River, the new levelized basis reflects the projected purchased capacity payments for the twelve-month period ended October 1992. The Federal Energy Regulatory Commission granted the Company recovery on a levelized basis of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners over their contractual purchased power buyback periods. As currently provided in rates in all jurisdictions, the Company recovers the costs of purchased energy and a portion of purchased capacity. The portion of costs not currently recovered through rates is being accumulated, and the Company is recording a carrying charge on the accumulated balance. The Company recovers the accumulated balance including the carrying charge when the capacity payments drop below the levelized revenues. In the North Carolina and wholesale jurisdictions, purchased capacity payments continue to exceed levelized revenues. In the South Carolina jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments. Jurisdictional levelizations are intended to recover total costs, including allowed returns, and are subject to adjustments, including final true-ups.

For the years ended December 31, 1993, 1992 and 1991, the Company recorded purchased capacity and energy costs from the other joint owners of $547,900,000, $514,300,000 and $536,500,000, respectively. These amounts, adjusted for the cost of capacity purchased not reflected in current rates, are included in "Net interchange and purchased power" in the Consolidated Statements of Income. As of December 31, 1993 and 1992, $768,099,000 pre-tax and $378,095,000 net of income tax, respectively, associated with the costs of capacity purchased but not reflected in current rates had been accumulated in the Consolidated Balance Sheets as "Purchased capacity costs." Accumulated deferred income taxes associated with "Purchased capacity costs" were $254,789,000 as of December 31, 1993. As of December 31, 1992, deferred income taxes reduced "Purchased capacity costs" on the Consolidated Balance Sheet by $265,255,000. The change in presentation from a net of tax to pre-tax basis is a result of the adoption of SFAS 109. (See Note 4.)

4. Income Tax Expense

The Company implemented Statement of Financial Accounting Standards No. 109 (SFAS 109), "Accounting for Income Taxes," effective January 1, 1993. No prior periods have been restated.

SFAS 109 requires a liability approach for financial accounting and reporting of income taxes. While classification of certain items on the Consolidated Balance Sheets has changed, principally because of

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certain items previously reported net of tax now being reported on a gross basis, there is no material effect on the Company's results of operations. As a result of implementing SFAS 109, the December 1993 Consolidated Balance Sheet reflects an increase of $778 million in both Total assets and Accumulated deferred income taxes (ADIT). The increase was primarily because of a change in presentation from a net of tax to pre-tax basis which resulted in an increase in "Purchased capacity costs" of $255 million and in the creation of the "Regulatory asset related to income taxes" of $486 million. Effective January 1, 1993, "Allowance for borrowed funds used during construction" on the Consolidated Statement of Income reflects a pre-tax cost of debt.

Accumulated deferred income taxes after implementation of SFAS 109 consist primarily of the following temporary differences (dollars in thousands):

[HARDCOPY PAGE 30]

	December 31, 1993
Excess tax over book depreciation at historical tax rates	$1,289,205
Regulatory liability related to adjusting deferred taxes to the current statutory tax rate	(124,952)*
Net excess tax over book depreciation	$1,164,253
Regulatory asset related to restating to a pre-tax basis	611,392*
Deferred Catawba purchased capacity costs	254,789
Book versus tax basis difference	110,594
Loss on bond redemptions	74,438
Other	(7,758)
Total deferred income taxes	$2,207,708

* The net regulatory asset related to income taxes is $486,440,000.

Total deferred income tax liability was $2,701,374,000 as of December 31, 1993. Total deferred income tax asset was $493,666,000 as of December 31, 1993.

Income tax expense consisted of the following (dollars in thousands):

	1993	1992
Income taxes related to electric expenses		
Current income taxes		
Federal	$278,279	$215,726

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State	60,948	47,116
	339,227	262,842
Deferred taxes, net		
Excess tax over book depreciation	60,760	86,046
Loss on bond redemptions	33,016	9,950
Pre-funded pension cost	19,751	–
Amortization of canceled construction costs	(17,890)	(23,959)
Deferred Catawba purchased capacity costs	2,841	7,271
Property taxes	(5,806)	(15,499)
Other	(17,682)	(25,756)
	74,990	38,053
Investment tax credit		
Deferred	–	–
Amortization of deferrals (credit)	(11,257)	(11,262)
	(11,257)	(11,262)
Total income taxes related to electric expenses	402,960	289,633
Income taxes related to other income		
Income taxes - return on deferred Catawba purchased capacity costs	20,702	18,845
Income taxes - other, net	3,390	8,630
Income taxes - (credit)	(16,371)	(13,790)
Total income taxes related to other income	7,721	13,685
Total income tax expense	$410,681	$303,318

(TABLE CONTINUED)

	1991
Income taxes related to electric expenses	
Current income taxes	
Federal	$232,121
State	54,335
	286,456
Deferred taxes, net	
Excess tax over book depreciation	60,976
Loss on bond redemptions	1,995
Pre-funded pension cost	–
Amortization of canceled construction costs	(23,959)
Deferred Catawba purchased capacity costs	8,163
Property taxes	(11,987)
Other	(16,977)
	18,211
Investment tax credit	
Deferred	2,273
Amortization of deferrals (credit)	(13,480)
	(11,207)
Total income taxes related to electric expenses	293,460
Income taxes related to other income	

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Income taxes - return on deferred Catawba purchased capacity costs	20,675
Income taxes - other, net	4,797
Income taxes - (credit)	(22,789)
Total income taxes related to other income	2,683
Total income tax expense	$296,143

Total current income taxes were $354,366,000 for 1993, $258,800,000 for 1992 and $268,686,000 for 1991. Of these amounts, state income taxes were $61,237,000 for 1993, $44,149,000 for 1992 and $48,671,000 for 1991. Total deferred income taxes were $67,572,000 for 1993, $55,780,000 for 1992 and $38,664,000 for 1991. Of these amounts, deferred state income taxes were $14,279,000 for 1993, $13,786,000 for 1992 and $10,833,000 for 1991.

[HARDCOPY PAGE 31]

Income taxes differ from amounts computed by applying the statutory tax rate to pre-tax income as follows (dollars in thousands):

	1993	1992	1991
Income taxes on pre-tax income at the statutory federal rate of 35% - 1993; 34% - 1992 and 1991	$362,984	$275,876	$299,120
Increase (reduction) in tax resulting from:			
Allowance for funds used during construction (AFUDC)	(6,027)	(7,221)	(23,832)
Amortization of electric investment tax credit deferrals	(11,257)	(11,262)	(13,480)
AFUDC in book depreciation/amortization	25,694	25,114	25,923
Deferred income tax flowback at rates higher than statutory	(9,091)	(21,685)	(22,561)
State income taxes, net of federal income tax benefits	49,292	37,878	39,345
Other items, net	(914)	4,618	(8,372)
Total income tax expense (see above)	$410,681	$303,318	$296,143

On August 10, 1993, President Clinton signed the Omnibus Budget Reconciliation Act of 1993 which includes an increase in the federal corporate income tax rate from 34% to 35%, retroactive to January 1, 1993. Accordingly, the Company's income tax expense reflects an increase of approximately $10 million for 1993.

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5. Short-Term Borrowings and Compensating-Balance Arrangements

To support short-term obligations, the Company had credit facilities of $324,980,000, $329,385,000 and $340,385,000 as of December 31, 1993, 1992 and 1991, with 29, 49 and 52 commercial banks, respectively. Included in these facilities is a three-year, $300,000,000 revolving credit agreement with the balance in separate, annually-renewable lines of credit. These facilities are on a fee or compensating-balance basis. No short-term debt resulting from these credit facilities was outstanding as of December 31, 1993, 1992 and 1991.

Cash balances maintained at the banks on deposit were $12,988,000 and $7,243,000 as of December 31, 1993 and 1992, respectively. Cash balances and fees compensate banks for their services, even though the Company has no formal compensating-balance arrangements. To compensate certain banks for credit facilities, the Company maintained balances of $49,000 and $509,000 as of December 31, 1993 and 1992, respectively. The Company retains the right of withdrawal with respect to the funds used for compensating-balance arrangements.

A summary of short-term borrowings is as follows (dollars in thousands):

	December 31, 1993	December 31, 1992
Amount outstanding at end of period - average rate of 3.27% as of December 31, 1993, 3.57% as of December 31, 1992 and 4.65% as of December 31, 1991	$ 18,000	$126,000
Maximum amount outstanding during the period	$ 178,000	$219,000
Average amount outstanding during the period	$ 35,187	$ 48,851
Weighted-average interest rate for the period - computed on a daily basis	3.17%	4.02%

(TABLE CONTINUED)

	Decemeber 31, 1991
Amount outstanding at end of period - average rate of 3.27% as of December 31, 1993, 3.57% as	

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of December 31, 1992 and 4.65% as of December 31, 1991	$ 86,000
Maximum amount outstanding during the period	$285,500
Average amount outstanding during the period	$ 92,090
Weighted-average interest rate for the period - computed on a daily basis	6.47%

6. Common Stock and Retained Earnings

Common Stock

Effective April 1, 1991, the Company began issuing common stock in lieu of purchasing shares on the open market for its various stock purchase plans. The Company discontinued issuances of common stock, effective December 1, 1991, and resumed open market purchases to satisfy the requirements of the various stock purchase plans. Except as discussed earlier, open market purchases were used to satisfy the requirements of the Company's various stock plans from 1991 through 1993.

During 1991 and through April 6, 1992, the Company issued common stock to satisfy the conversion rights of preference stock. (See Note 7.)

As of December 31, 1993, a total of 7,004,659 shares was reserved for issuance to stock plans.

Retained Earnings

As of December 31, 1993, none of the Company's retained earnings were restricted as to the declaration or payment of dividends.

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7. Preferred and Preference Stock Without Sinking Fund Requirements

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1993 and 1992:

	Par Value	Shares
Preferred Stock	$100	12,500,000
Preferred Stock A	25	10,000,000

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Preference Stock	100	1,500,000

On April 6, 1992, the Company redeemed all outstanding shares of the Cumulative Preference Stock, 63/4% Convertible Series AA at its par value of $100 per share.

In 1992 and 1991, shares of preference stock were converted into shares of common stock as follows:

Year	Preference Shares	Common Shares
1992	19,060	159,386
1991	1,846	15,440

Preferred and preference stock without sinking fund requirements as of December 31, 1993 and 1992, were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1993	1992
4.50% C	1964	350,000	$ 35,000	$35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
8.20% G	1971	600,000	-	60,000
7.80% H	1972	600,000	-	60,000
8.28% K	1977	500,000	-	50,000
7.85% S	1992	600,000	60,000	60,000
7.00% W	1993	500,000	50,000	-
7.04% Y	1993	600,000	60,000	-
7.72% (Preferred Stock A)	1992	1,600,000	40,000	40,000
6.375% (Preferred Stock A)	1993	2,400,000	60,000	-
Adjustable Rate A	1986	500,000	50,000	50,000
Auction Series A	1990	750,000	75,000	75,000
			$500,000	$500,000

8. Preferred Stock With Sinking Fund Requirements

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1993 and 1992:

	Par Value	Shares
Preferred Stock	$100	12,500,000
Preferred Stock A	25	10,000,000
Preference Stock	100	1,500,000

Preferred stock with sinking fund requirements as of December 31, 1993

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and 1992, was as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1993	1992
5.95% B (Preferred Stock A)	1992	800,000	$20,000	$20,000
6.10% C (Preferred Stock A)	1992	800,000	20,000	20,000
6.20% D (Preferred Stock A)	1992	800,000	20,000	20,000
7.875% P	1986	485,000	-	48,500
7.12% Q	1987	485,000	48,500	48,519
7.50% R	1992	850,000	85,000	85,000
6.20% T	1992	130,000	13,000	13,000
6.30% U	1992	130,000	13,000	13,000
6.40% V	1992	130,000	13,000	13,000
6.75% X	1993	500,000	50,000	-
Less: Current sinking fund requirements				
7.875% P			-	(1,500)
7.12% Q			(1,500)	-
			$281,000	$279,519

The annual sinking fund requirements through 1998 are $1,500,000 in 1994, 1995, 1996 and 1997 and $5,750,000 in 1998. Some additional redemptions are permitted at the Company's option. The Company reacquired 15,000 shares of 7.12% Series Q Preferred Stock in 1992 to satisfy 1993 sinking fund requirements.

The call provisions for the outstanding preferred stock specify various redemption prices not exceeding 105 percent of par value, plus accumulated dividends to the redemption date.

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9. Long-Term Debt

Long-term debt outstanding as of December 31, 1993 and 1992, was as follows (dollars in thousands):

Series	Year Due	1993	1992
First and refunding mortgage bonds:			
6.06%-6.23%	1994	$81,700	$81,700
6.47%-6.60%	1995	40,300	40,300
4 1/2%	1995	40,000	40,000
6.59%	1996	3,000	3,000

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7 7/8%	1996	-	100,000
5 3/8%	1997	72,600	72,600
5 5/8%	1997	100,000	100,000
6 3/8%	1998	-	68,500
5.17%	1998	50,000	-
7%	1999	-	56,075
7.5%	1999	100,000	100,000
6 1/4%	1999	65,000	65,000
5.76%	1999	5,000	-
5.78%	1999	25,000	-
5.79%	1999	30,000	-
7%	2000	100,000	100,000
7% B	2000	100,000	100,000
7 1/2%	2001	-	97,900
7 3/8% B	2001	-	38,050
5 7/8%	2001	150,000	-
7 3/4%	2002	-	78,100
7 3/8% B	2002	-	67,900
6 5/8% B	2003	100,000	-
7 3/4%	2003	-	94,872
5 7/8% C	2003	75,000	-
6.125%	2003	75,000	-
8%	2004	75,000	75,000
6 1/4% B	2004	100,000	-
7.37%-7.41%	2004	100,000	100,000
7%	2005	200,000	200,000
8 1/8%	2007	-	119,500
6 3/8%	2008	125,000	-
9%	2016	-	175,000
8 1/2%	2017	-	150,000
9 5/8%	2020	46,982	200,000
10 1/8% B	2020	24,854	150,000
8 3/4%	2021	150,000	150,000
8 3/8% B	2021	150,000	150,000
8 5/8%	2022	100,000	100,000
7 3/8%	2023	200,000	-
6 7/8%	2023	200,000	-
6 3/4%	2025	150,000	-
8.95%	2027	15,851	15,925
7%	2033	150,000	-
Pollution-Control bonds:			
9 1/8%	2013	-	77,000
7.70%	2012	20,000	20,000
7.75% B	2017	10,000	10,000
7.50%	2017	25,000	25,000
2.55%	2014	40,000	-
2.60%	2014	-	40,000
5.80%	2014	77,000	-
Subtotal		3,172,287	3,061,422

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Other long-term debt:		
Capitalized leases	47,029	53,782
Other long-term debt	130,000	130,000
Unamortized debt discount and premium, net	(61,128)	(35,940)
Current maturities of long-term debt	(89,156)	(6,827)
Subtotal (a)	3,199,032	3,202,437
Subsidiary long-term debt:		
Crescent Resources, Inc. (b)	54,149	53,207
Nantahala Power and Light (c)	33,458	33,574
Current maturities of long-term debt	(1,242)	(1,107)
Subtotal	86,365	85,674
Total consolidated long-term debt	$3,285,397	$3,288,111

(a) Substantially all the Company's electric plant was mortgaged as of December 31, 1993.

(b) Substantial amounts of Crescent Resources, Inc.'s real estate development projects, land and buildings are pledged as collateral.

(c) Nantahala Power and Light's loan agreements impose net worth restrictions and limitations on disposal of assets and payment of cash dividends.

As of December 31, 1993 and 1992, the Company had $40,000,000 in pollution-control revenue bonds backed by an unused, two-year revolving credit facility of $40,000,000 and $130,000,000 in commercial paper backed by an unused, three-year $130,000,000 revolving credit facility. These facilities are on a fee basis. Both the $40,000,000 in pollution-control bonds and the $130,000,000 in commercial paper are included in long-term debt.

As of December 31, 1993, Crescent Resources, Inc. had $52,064,000 in mortgage loans which mature in 1997 and require monthly payments of principal. Interest rates are variable and ranged from 4.21 percent to 5.08 percent as of December 31, 1993. Nantahala Power and Light had $33,000,000 in senior notes maturing in 2011 and 2012 as of December 31, 1993. The two notes carry fixed interest rates of 9.21 percent and 7.45 percent and require prepayments beginning 1997 and 1998, respectively.

The annual maturities of consolidated long-term debt, including capitalized lease principal payments through 1998, are $90,398,000 in 1994; $89,888,000 in 1995; $13,264,000 in 1996; $223,810,000 in 1997 and $54,522,000 in 1998.

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10. Fair Value of Financial Instruments

Estimated fair value amounts have been determined by the Company using available market information and appropriate valuation methodologies. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 1993, are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

Cash, Short-term investments and Notes payable

The carrying amount approximates fair value because of the short maturity of these instruments.

Long-term debt (excluding Capitalized leases) and Preferred stock with sinking fund requirements

Fair value is based on market price estimates. As a result of substantial refinancing activity in 1993 and 1992, the Company's book value of consolidated long-term debt and preferred stock is not materially different from fair market value as of December 31, 1993.

Nuclear decommissioning trust funds

External funds have been established, as required by the Nuclear Regulatory Commission, as a mechanism to fund certain costs of nuclear decommissioning. (See Note 16.) These nuclear decommissioning trust funds are primarily invested in intermediate-term municipal bonds. As of December 31, 1993, the Company's book value of its nuclear decommissioning trust funds is not materially different from fair market value.

11. Investment in Joint Ventures

Certain investments in joint ventures are accounted for by the equity method. The Company's ownership in domestic and international joint ventures is 50 percent or less. Total assets of these joint ventures as of December 31, 1993 and 1992, were $972 million and $433 million, respectively. The Company's proportionate share of these assets was $241 million and $163 million, respectively. Total liabilities of these joint ventures as of December 31, 1993 and 1992, were $413 million and $321 million, respectively. The Company's proportionate share of the liabilities was $139 million and $132 million, respectively. Of the $413 million total liabilities outstanding at

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December 31, 1993, $290 million represents non-recourse debt for which the Company bears no responsibility in the event the joint venture defaults on the debt. The Company's portion of net income from the joint ventures for the years ended December 31, 1993 and 1992, was $2,601,000 and ($1,179,000).

12. Retirement Benefits

A. Retirement Plan

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own retirement plans, have a non-contributory, defined benefit retirement plan covering substantially all their employees. The benefit is based on years of creditable service and the employee's average compensation based on the highest compensation during a consecutive sixty-month period. Prior to 1992, benefits have been reduced by a Social Security adjustment for employees age sixty-five and over and for early retirees with no creditable service prior to September 1, 1980. During 1991, the Company amended its plan for employees who retire after December 31, 1991. The effect of this amendment was to reduce benefits by a Social Security adjustment for all retirees. The plan was amended in 1992 to permit participants with 30 years of creditable service to retire as early as age 51. The Company's policy is to fund pension costs as accrued. During 1993, the Company made a one-time contribution of $50,000,000 to enhance the funded position of the plan.

Net periodic pension cost for the years ended December 31, 1993, 1992 and 1991, include the following components (dollars in thousands):

	1993	1992	1991
Service cost benefit earned during the year	$39,514	$35,701	$37,286
Interest cost on projected benefit obligation	93,347	85,613	79,175
Actual return on plan assets	(117,898)	(50,897)	(127,978)
Amount deferred for recognition	35,652	(32,277)	52,574
Expected return on plan assets	(82,246)	(83,174)	(75,404)
Net amortization	4,137	3,812	4,347
Net periodic pension cost	$54,752	$41,952	$45,404

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A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1993 and 1992, is as follows (dollars in thousands):

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	1993	1992
Accumulated benefit obligation:		
Vested benefits	$ (1,087,705)	$ (920,228)
Nonvested benefits	(3,946)	(2,915)
Accumulated benefit obligation	$ (1,091,651)	$ (923,143)
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$1,137,992	$980,661
Projected benefit obligation	(1,311,921)	(1,132,410)
Unrecognized net experience loss	265,566	204,145
Unrecognized prior service cost reduction	(42,705)	(45,911)
Remaining unrecognized transitional obligation	1,068	1,202
Prepaid pension cost	$50,000	$7,687

In determining the projected benefit obligation, the weighted-average assumed discount rate used was 7.50 percent in 1993 and 8.25 percent in 1992 and 1991. The assumed increase in future compensation level for determining the projected benefit obligation is based on an age-related basis. The weighted-average salary increase was 4.50 percent in 1993, 5.40 percent in 1992 and 5.65 percent in 1991. The expected long-term rate of return on plan assets used in determining pension cost was 8.40 percent in 1993 and 9.25 percent in 1992 and 1991.

During 1993 the Company offered an enhanced early retirement option, Limited Period Separation Opportunity (LPSO), for eligible employees. The Company recorded an additional one-time expense for special termination benefits associated with LPSO of approximately $7,611,000.

B. Postretirement Benefits

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own postretirement benefit plans, currently provides certain health care and life insurance benefits for retired employees. Employees become eligible for these benefits if they retire at age 55 or greater with 10 years of service; or if they retire as early as age 51 with 30 years or more of service. Employees retiring after January 1, 1992, receive a fixed Company allowance, based on years of service, to be used to pay medical insurance premiums. The Company reserves the right to terminate, suspend, withdraw, amend or modify the plans in whole or in part at any time. In 1992, the Company commenced funding the maximum amount allowable under section 401(h) of the Internal Revenue Code, which provides for tax deductions for contributions and tax-free accumulation of investment income. Such amounts partially fund the Company's medical and dental postretirement benefits. The Company has also established a Retired Lives Reserve, which has tax attributes similar to 401(h) funding, to partially fund its postretirement life

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insurance obligation. The Company contributed $14,648,000 into these funding mechanisms in 1993 and $19,338,000 in 1992. In 1992, the Company implemented a new accounting standard that requires postretirement benefits to be recognized as earned by employees rather than recognized as paid. Prior to 1992, the cost of retiree benefits was recognized as the benefits were paid. Amounts paid by the Company for 1991 amounted to $11,900,000.

[HARDCOPY PAGE 36]

Net periodic postretirement benefit cost for the years ended December 31, 1993 and 1992, include the following components (dollars in thousands):

	1993	1992
Service cost benefit earned during the year	$4,974	$4,644
Interest cost on accumulated postretirement benefit obligation	25,482	23,347
Actual return on plan assets	(4,143)	(2,953)
Amount deferred for recognition	334	1,061
Expected return on plan assets	(3,809)	(1,892)
Straight line - 20 year amortization of transition obligation	13,479	13,479
Other amortization	278	160
Net periodic postretirement benefit cost	$40,404	$39,738

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1993 and 1992, is as follows (dollars in thousands):

	1993	1992
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$57,840	$41,634
Actives eligible to retire	(21,810)	(14,954)
Actives not eligible to retire	(90,621)	(74,900)
Retirees and surviving spouses	(238,522)	(213,018)
Accumulated postretirement benefit obligation	(350,953)	(302,872)
Unrecognized prior service cost	1,923	2,083
Unrecognized net experience (gain)/loss	29,127	(2,501)

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Unrecognized transitional obligation	242,629	256,108
(Accrued) postretirement benefit cost	$ (19,434)	$ (5,548)

In determining the accumulated postretirement benefit obligation (APBO), the weighted-average assumed discount rate used was 7.50 percent in 1993 and 8.25 percent in 1992. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 4.50 percent in 1993, 5.40 percent in 1992 and 5.65 percent in 1991. The expected long-term rate of return on 401(h) assets used in determining postretirement benefits cost was 8.40 percent in 1993 and 9.25 percent in 1992. For Retired Lives Reserve assets, 7.125 percent was used in 1993 and 1992.

The assumed medical inflation rate was approximately 13 percent in 1993. This rate decreases by 0.5 percent to 1.0 percent per year until a rate of 5.5 percent is achieved in the year 2002, which remains fixed thereafter.

A 1.0 percent increase in the medical and dental trend rates produces a 6.25 percent ($1,903,213) increase in the aggregate service and interest cost. The increase in the APBO attributable to a 1.0 percent increase in the medical and dental trend rates is 6.69 percent ($23,483,182) as of December 31, 1993.

13. Commitments and Contingencies

A. Construction Program

Projected construction and nuclear fuel costs, both including allowance for funds used during construction, are $2.3 billion and $394 million, respectively, for 1994 through 1996. The program is subject to periodic review and revisions, and actual construction costs incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

B. Nuclear Insurance

The Company maintains nuclear insurance coverage in three areas: liability coverage, property, decontamination and decommissioning coverage, and extended accidental outage coverage to cover increased generating costs and/or replacement power purchases. The Company is being reimbursed by the other joint owners of the Catawba Nuclear Station for certain expenses associated with nuclear insurance premiums paid by the Company. Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $9.4 billion. The maximum required private primary insurance of $200

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million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $9.2 billion, which will be increased by $75.5 million as each additional commercial nuclear reactor is

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licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. The $9.2 billion could also be reduced by $75.5 million for certain nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs and public liability damages exceed primary insurances, licensees may be assessed up to $75.5 million for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $75.5 million amount is subject to indexing for inflation. This amount is further subject to a surcharge of 5 percent (which is included in the above $9.4 billion figure) if funds are insufficient to pay claims and associated costs. If retrospective premiums were to be assessed, the other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of such assessment.

The Company is a member of Nuclear Mutual Limited (NML), which provides $500 million in primary property damage coverage for each of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $42 million. This amount represents 5 times the Company's annual premium to NML.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases $1.4 billion of insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, the Company will be liable, on a pro rata basis, for additional assessments of up to $46 million. This amount is limited to 7.5 times the Company's annual premium to NEIL for excess property, decontamination and decommissioning liability insurance. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to Catawba. The Company has also purchased an additional $400 million of excess property damage insurance for its Oconee and McGuire plants and $800 million for its Catawba plant through a pool of stock and mutual insurance companies.

The Company participates in a NEIL program that provides insurance for

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the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Each unit of the Oconee, McGuire and Catawba Nuclear Stations is insured for up to approximately $3.5 million per week, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100 percent for 52 weeks, and 67 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $30 million. This amount represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to the joint ownership agreements.

C. Other

The other joint owners of the Catawba Nuclear Station and the Company are involved in various proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding is that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information, see Note 3.) The Company and two of the four joint owners have entered into a proposed settlement agreement which, if approved by the regulators, will resolve all issues in contention in such proceedings between the Company and these owners. The Company recorded a liability as an increase to Other current liabilities on its Consolidated Balance Sheets of approximately $105 million in 1993 to reflect this proposed settlement. In addition, future estimated obligations in connection with the settlement are reflected in estimates of purchased capacity obligations in Note 3. As the Company expects the costs associated with this settlement will be recovered as part of the purchased capacity levelization, the Company has included approximately $105 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Although the two other Catawba joint owners, who are not parties to the above settlement, have not fully quantified the dollars associated with their claims in the presently outstanding proceedings, information associated with these proceedings indicates that the amount in contention could be as high as $110 million through December 31, 1993. Arbitration hearings were held in 1992 involving substantially all the disputed amounts, and a decision interpreting the language of the agreements on certain of these matters was issued on October 1, 1993.

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Further proceedings will be required to determine the amounts associated with this decision as it relates to these owners, some of which may involve refunds. However, the Company expects the costs associated with this decision will be included in and recovered as part of the purchased capacity levelization consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

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14. Other Income

For the years ended December 31, 1993, 1992 and 1991, the Company reported carrying charges on purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station of $32,180,000, $28,820,000 and $28,765,000 (net of taxes), respectively, as components of "Other, net" and "Income taxes - other, net" on the Consolidated Statements of Income. (For additional information on purchased capacity levelization, see Note 3.)

Also included in "Other, net" and "Income taxes - other, net" on the Consolidated Statements of Income is income provided by diversified activities and the Company's subsidiaries of $21,996,000, $25,728,000 and $23,587,000 (net of taxes) for years ended December 31, 1993, 1992 and 1991, respectively. The activities of Crescent Resources, Inc., the Company's real estate development and forest management subsidiary, generated the majority of subsidiary and non-electric earnings. Other components include subsidiary investment income, fees for engineering services, construction and operation of generation and transmission facilities outside the Company's current service area, water operations and merchandising.

For the year ended December 31, 1991, the Company recorded a net of tax carrying charge of $36,765,000 on costs incurred on the Bad Creek Hydroelectric Station after commercial operation but prior to recovery of costs through rates. This carrying charge is a component of "Other, net" in the Consolidated Statements of Income.

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15. Reclassification

In the Consolidated Statements of Cash Flows, Consolidated Balance Sheets and the Consolidated Statements of Capitalization, certain prior-year information has been reclassified to conform with 1993 classifications.

16. Nuclear Decommissioning Costs

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $955 million stated in 1990 dollars. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are liable for providing decommissioning related to their ownership interests in the station. Both the NCUC and the PSCSC have granted the Company recovery of the estimated site-specific decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume that units will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 - 2013, Oconee 3 - 2014; McGuire 1 - 2021, McGuire 2 - 2023; and Catawba 1 - 2024, Catawba 2 - 2026.

The Nuclear Regulatory Commission (NRC) issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1993, the Company expensed approximately $52.5 million which was contributed to the external funds and accrued an additional $5.0 million to the internal reserve. The balance of the external funds as of December 31, 1993, was $118.5 million. The balance of the internal reserve as of December 31, 1993, was $200.0 million and is reflected in Accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the estimated site-specific decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 4.5 percent to 5.5 percent, are currently sufficient to provide for the cost of decommissioning based on the Company's current decommissioning schedule.

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Independent Auditors' Report

Duke Power Company:

We have audited the consolidated financial statements of Duke Power Company and subsidiaries (the Company) listed in the accompanying index on page 22. Our audits also included the consolidated financial statement schedules listed in the accompanying index on page 22. These financial statements and consolidated financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and consolidated financial statement schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1993 and 1992, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1993 in conformity with generally accepted accounting principles. Also, in our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 4 to the consolidated financial statements, in 1993, the Company changed its method of accounting for income taxes to conform with Statement of Financial Accounting Standards No. 109.

DELOITTE & TOUCHE

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Deloitte & Touche
Charlotte, North Carolina
February 11, 1994

Responsibility for Financial Statements

The financial statements of Duke Power Company are prepared by management, which is responsible for their integrity and objectivity. The statements are prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions which should be included. The other information in the annual report is consistent with the financial statements. In preparing these statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed according to management's authorization. Internal accounting controls also provide reasonable assurance that transactions are recorded properly, so that financial statements can be prepared according to generally accepted accounting principles. In addition, the Company's accounting controls provide reasonable assurance that errors or irregularities which could be material to the financial statements are prevented or are detected by employees within a timely period as they perform their assigned functions. The Company's accounting controls are continually reviewed for effectiveness. In addition, written policies, standards and procedures, and a strong internal audit program augment the Company's accounting controls.

The Board of Directors pursues its oversight role for the financial statements through the audit committee, which is composed entirely of directors who are not employees of the Company. The audit committee meets with management and internal auditors periodically to review the work of each group and to monitor each group's discharge of its responsibilities. The audit committee also meets periodically with the Company's independent auditors, Deloitte & Touche. The independent auditors have free access to the audit committee and the Board of Directors to discuss internal accounting control, auditing and financial reporting matters without the presence of management.

DAVID E. HAUSER

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David L. Hauser
Controller

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SELECTED QUARTERLY FINANCIAL DATA

Dollars in Thousands (except per-share data)	First Quarter	Second Quarter	Third Quarter
1993 by quarter			
Electric Revenues	$1,007,783	$987,218	$1,289,994
Electric Operating Income	188,522	169,111	283,411
Net Income	141,684	122,470	241,409
Earnings Per Share	$0.63	$0.53	$1.12
1992 by quarter			
Electric Revenues	$981,330	$899,319	$1,139,525
Electric Operating Income	161,726	148,888	248,081
Net Income	106,365	86,938	190,519
Earnings Per Share	$0.45	$0.36	$0.85

(TABLE CONTINUED)

Dollars in Thousands (except per-share data)	Fourth Quarter	Total
1993 by quarter		
Electric Revenues	$996,881	$4,281,876
Electric Operating Income	173,021	814,065
Net Income	120,852	626,415
Earnings Per Share	$0.52	$2.80
1992 by quarter		
Electric Revenues	$941,310	$3,961,484
Electric Operating Income	166,000	724,695
Net Income	124,261	508,083
Earnings Per Share	$0.55	$2.21

Generally, quarterly earnings fluctuate with seasonal weather conditions, timing of rate changes and maintenance of electric generating units, especially nuclear units.

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SUBSIDIARY HIGHLIGHTS

The earnings contribution of the Company's diversified activities and

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subsidiaries was $22.0 million in 1993, $25.7 million in 1992 and $23.6 million in 1991. (a)(b) Highlights of selected subsidiaries are presented below. (dollars in thousands)

ELECTRIC POWER SUPPLY

Nantahala Power and Light Company provides service to a five-county area in the western North Carolina mountains by its operation of 11 hydroelectric stations and purchases of supplemental power.

	1993	1992	1991
Assets net of liabilities	$ 47,679	$ 42,910	$ 39,384
Net income	$ 4,261	$ 3,526	$ 2,721
Number of employees (c)	194	191	194

FUNDS MANAGEMENT

Church Street Capital Corp. (CSCC) manages investment of funds for the Company and is the parent company of several subsidiaries. CSCC has no full-time employees.

	1993	1992	1991
Short-term investments and marketable securities	$ 155,871	$ 173,347	$ 120,303
Investment income (after tax)	$ 3,548	$ 5,404	$ 6,397

Highlights of CSCC's subsidiaries are presented below:

REAL ESTATE MANAGEMENT, LAND DEVELOPMENT

Crescent Resources, Inc is engaged in forest management, real estate development, and sales and leasing

	1993	1992	1991
Asset net of liabilities	$133,034	$ 110,949	$ 88,046
Net income (a)	$ 16,327	$ 16,613	$ 9,661
Number of employees (c)	77	73	69

ENGINEERING, CONSTRUCTION, TECHNICAL SERVICES AND POWER DEVELOPMENT

Engineering, construction, technical services and power development opportunities are pursued nationally and internationally.

Duke Engineering & Services, Inc. markets engineering, construction, quality assurance, consulting and other engineering-related services for utility facilities other than coal-fired plants.

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Duke/Fluor Daniel, a joint venture with Fluor Daniel, Inc., provides design, construction, operation and maintenance support primarily for coal-fired generating plants.

Duke Energy Group, parent of Duke Energy Corp., structures, finances and manages investments in electric generation and transmission facilities.

	1993	1992	1991
Assets net of liabilities	$127,708	$ 36,687	$ 13,480
Net income	$ 40	$ 33	$ 1,512
Number of employees (c)	518	495	364

(a) 1991 EXCLUDES THE CUMULATIVE EFFECT OF AN ACCOUNTING CHANGE OF $6,727,000, AFTER TAX.

(b) THE EARNINGS CONTRIBUTION OF THE COMPANY'S SUBSIDIARIES AND NON-ELECTRIC OPERATIONS INCLUDES ELIMINATION OF INTERCOMPANY PROFIT OF $509,000 AND $1,211,000, AFTER TAX, IN 1993 AND 1992, RESPECTIVELY.

(c) FULL-TIME EMPLOYEES.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

No events necessary to be disclosed by the Company under this item have occurred.

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PART III.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

Information for this item concerning directors of the Company is set forth in the sections entitled "Election of Directors" and "Information Regarding the Board of Directors" in the proxy statement of the Company relating to its 1994 annual meeting of shareholders, which is being incorporated herein by reference.

Information concerning the executive officers of the Company is set forth under the section entitled "Executive Officers of the Company" in this annual report.

ITEM 11. EXECUTIVE COMPENSATION.

Information for this item is set forth in the section entitled "Executive Compensation" in the proxy statement of the Company relating to its 1994 annual meeting of shareholders, which is being incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

Information for this item is set forth in the sections entitled "Voting

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Securities Outstanding" and "Election of Directors" in the proxy statement of the Company relating to its 1994 annual meeting of shareholders, which is being incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Information for this item is set forth in the section entitled "Election of Directors" in the proxy statement of the Company relating to its 1994 annual meeting of shareholders, which is being incorporated herein by reference.

PART IV.

ITEM 14. EXHIBITS, CONSOLIDATED FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a) Consolidated Financial Statements, Supplemental Financial Data and Consolidated Financial Statement Schedules included in Part II of this annual report are as follows:

Consolidated Financial Statements

Consolidated Statements of Income for the Three Years Ended December 31, 1993

Consolidated Statements of Cash Flows for the Three Years Ended

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December 31, 1993

Consolidated Balance Sheets --December 31, 1993 and 1992

Consolidated Statements of Capitalization --December 31, 1993 & 1992

Consolidated Statements of Retained Earnings for the Three Years Ended December 31, 1993
s to Consolidated Financial Statements

Selected Quarterly Financial Data (Unaudited)

Consolidated Financial Statement Schedules

Schedule V --Property, Plant and Equipment for the Three Years Ended December 31, 1993

Schedule VI --Accumulated Depreciation and Amortization of Property, Plant and Equipment for the Three Years Ended December 31, 1993

Schedule VIII --Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 1993

Schedule X --Supplementary Consolidated Income Statement Information for the Three Years Ended December 31, 1993

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All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

(b) Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1993.

(c) Exhibits --See Exhibit Index on page 48.

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EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the Securities and Exchange Commission and pursuant to Rule 12b-32 are incorporated herein by reference.

EXHIBIT
NUMBER

3-A –Restated Articles of Incorporation of registrant, dated as of October 6, 1993 (filed with Form S-3, File No. 33-50617, effective October 20, 1993, as Exhibit 4(A)).

3-B –Articles of Amendment of registrant dated November 1, 1993, relating to the 6.375% Cumulative Preferred Stock A, 1993 Series (filed with Form S-3, No. 33-52479, effective March 29, 1994, as Exhibit 4(B)).

3-C –By-Laws of registrant, as amended (filed with Form S-3, No. 33-50584, effective August 11, 1992, as Exhibit 3(g)).

4-B-1 –First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated as of December 1, 1927 (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(a)).

4-B-2 –Supplemental Indenture, dated as of March 12, 1930, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).

4-B-3 –Supplemental Indenture, dated as of July 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(c)).

4-B-4 –Supplemental Indenture, dated as of December 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(d)).

4-B-5 –Supplemental Indenture, dated as of September 1, 1936, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).

4-B-6 –Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).

4-B-7 –Supplemental Indenture, dated as of April 1, 1944 supplementing

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said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).

4-B-8 --Supplemental Indenture, dated as of September 1, 1947 supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).

4-B-9 --Supplemental Indenture, dated as of September 8, 1947 supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).

4-B-10 --Supplemental Indenture, dated as of February 1, 1949 supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).

4-B-11 --Supplemental Indenture, dated as of March 1, 1949 supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).

4-B-12 --Supplemental Indenture, dated as of April 1, 1951 supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(l)).

4-B-13 --Supplemental Indenture, dated as of September 1, 1953 supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-13).

4-B-14 --Supplemental Indenture, dated as of October 1, 1954 supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).

4-B-15 --Supplemental Indenture, dated as of January 1, 1955 supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-15).

4-B-16 --Supplemental Indenture, dated as of May 1, 1956 supplementing said Mortgage (filed with Form S-9, File No. 2-12402 effective April 26, 1956, as Exhibit 2-B-16).

4-B-17 --Supplemental Indenture, dated as of January 1, 1960 supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).

4-B-18 --Supplemental Indenture, dated as of February 1, 1960 supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).

4-B-19 --Supplemental Indenture, dated as of February 1, 1962 supplementing said Mortgage (filed with Form S-9, File No. 2-20577, effective August 16, 1962, as Exhibit 2-B-20).

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4-B-20 --Supplemental Indenture, dated as of August 1, 1962 supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-19).

[HARDCOPY PAGE 49]

EXHIBIT
NUMBER

4-B-21 --Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 3, 1966, as Exhibit 4-B-20).

4-B-22 --Supplemental Indenture, dated as of February 1, 1965, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-21).

4-B-23 --Supplemental Indenture, dated as of April 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-28023, effective February 15, 1968, as Exhibit 2-B-25).

4-B-24 --Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No. 2-31304, effective January 21, 1969, as Exhibit 2-B-26).

4-B-25 --Supplemental Indenture, dated as of February 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-34289, effective August 27, 1969, as Exhibit 2-B-27).

4-B-26 --Supplemental Indenture, dated as of September 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-36095, effective February 16, 1970, as Exhibit 2-B-39).

4-B-27 --Supplemental Indenture, dated as of March 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-37953, effective July 28, 1970, as Exhibit 2-B-42).

4-B-28 --Supplemental Indenture, dated as of August 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-39451, effective March 4, 1971, as Exhibit 2-B-28).

4-B-29 --Supplemental Indenture, dated as of March 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-42404, effective December 7, 1971, as Exhibit 2-B-29).

4-B-30 --Supplemental Indenture, dated as of December 1, 1971, supplementing said Mortgage (filed with Form S-7, File No.

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2-43122, effective March 7, 1972, as Exhibit 2-B-30).

4-B-31 --Supplemental Indenture, dated as of April 1, 1972, supplementing said Mortgage (filed with Form S-7 File No. 2-46208, effective November 20, 1972, as Exhibit 2-B-31).

4-B-32 --Supplemental Indenture, dated as of December 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-48058, effective June 5, 1973, as Exhibit 2-B-32).

4-B-33 --Supplemental Indenture, dated as of June 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-49333, effective November 5, 1973, as Exhibit 2-B-33).

4-B-34 --Supplemental Indenture, dated as of November 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-50493, effective April 25, 1974, as Exhibit 2-B-34).

4-B-35 --Supplemental Indenture, dated as of May 1, 1974, supplementing said Mortgage (filed with Form S-7, File No. 2-52669, effective February 11, 1975, as Exhibit 2-B-35).

4-B-36 --Supplemental Indenture, dated as of February 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-36).

4-B-37 --Supplemental Indenture, dated as of July 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-37).

4-B-38 --Supplemental Indenture, dated as of October 1, 1976, supplementing said Mortgage (filed with Form S-7, File No. 2-59494, effective August 10, 1977, as Exhibit 2-B-38).

4-B-39 --Supplemental Indenture, dated as of Sepember 1, 1977, supplementing said Mortgage (filed with Form S-7, File No. 2-61995, effective July 26, 1978, as Exhibit 2-B-39).

4-B-40 --Supplemental Indenture, dated as of August 1, 1978, supplementing said Mortgage (filed with Form S-7, File No. 2-64541, effective June 7, 1979, as Exhibit 2-B-40).

4-B-41 --Supplemental Indenture, dated as of June 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-65371, effective October 2, 1979, as Exhibit 2-B-41).

4-B-42 --Supplemental Indenture, dated as of October 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-66659, effective March 12, 1980, as Exhibit 2-B-42).

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4-B-43 --Supplemental Indenture, dated as of March 1, 1980, supplementing said Mortgage (filed with Form S-16, File No.2-68571, effective August 19, 1980, as Exhibit 2-B-43).

4-B-44 --Supplemental Indenture, dated as of August 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-44).

4-B-45 --Supplemental Indenture, dated as of March 1, 1982, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-45).

4-B-46 --Supplemental Indenture, dated as of September 1, 1982, supplementing said Mortgage (filed with Form S-3, File No. 2-78882, effective August 30, 1982, as Exhibit 4-B-46).

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EXHIBIT
NUMBER

4-B-47 --Supplemental Indenture, dated as of May 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-47).

4-B-48 --Supplemental Indenture, dated as of September 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-48).

4-B-49 --Supplemental Indenture, dated as of September 1, 1984, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-49).

4-B-50 --Supplemental Indenture, dated as of March 1, 1985, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-50).

4-B-51 --Supplemental Indenture, dated as of December 1, 1985, supplementing said Mortgage (filed with Form S-3, File No. 33-5163, effective May 2, 1986, as Exhibit 4-B-51).

4-B-52 --Supplemental Indenture, dated as of April 1, 1986, supplementing said Mortgage (filed with Form S-3, File No. 33-5163, effective May 2, 1986, as Exhibit 4-B-52).

4-B-53 --Supplemental Indenture, dated as of May 1, 1986, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-53).

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4-B-54 --Supplemental Indenture, dated as of June 1, 1986, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-54).

4-B-55 --Supplemental Indenture, dated as of February 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-55).

4-B-56 --Supplemental Indenture, dated as of February 15, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-56).

4-B-57 --Supplemental Indenture, dated as of March 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-57).

4-B-58 --Supplemental Indenture, dated as of October 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1987, File No. 1-4928, as Exhibit 4-B-58).

4-B-59 --Supplemental Indenture, dated as of February 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1989, File No. 1-4928, as Exhibit 4-B-59).

4-B-60 --Supplemental Indenture, dated as of March 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-60).

4-B-61 --Supplemental Indenture, dated as of May 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-61).

4-B-62 --Supplemental Indenture, dated as of May 15, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-62).

4-B-63 --Supplemental Indenture, dated as of March 1, 1991, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-63).

4-B-64 --Supplemental Indenture, dated as of July 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-64).

4-B-65 --Supplemental Indenture, dated as of December 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-65).

4-B-66 --Supplemental Indenture, dated as of March 1, 1992,

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supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1991, File No. 1-4928, as Exhibit 4-B-66).

4-B-67 --Supplemental Indenture, dated as of June 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-67).

4-B-68 --Supplemental Indenture, dated as of July 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-68).

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EXHIBIT
NUMBER

4-B-69 --Supplemental Indenture, dated as of September 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-53308, effective November 24, 1992, as Exhibit 4-B-69).

4-B-70 --Supplemental Indenture, dated as of February 1, 1993, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, as Exhibit 4-B-70).

4-B-71 --Supplemental Indenture, dated as of March 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-59448, effective March 17, 1993, as Exhibit 4-B-71).

4-B-72 --Supplemental Indenture, dated as of April 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-72).

4-B-73 --Supplemental Indenture, dated as of May 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-73).

4-B-74 --Supplemental Indenture, dated as of June 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-74).

4-B-75 --Supplemental Indenture, dated as of July 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-75).

4-B-76 --Supplemental Indenture, dated as of August 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-76).

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4-B-77 --Supplemental Indenture, dated as of August 20, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-77).

10-A --Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).

10-B --Agreement, dated August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).

10-C --Agreement, dated October 14, 1980 between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

10-D --Agreement, dated October 14, 1980 between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

10-E(dagger) --Employees' Stock Ownership Plan.

*10-F --Employee Incentive Plan.

*10-G --1993 Executive Long-Term Incentive Plan.

10-H(@) --Supplemental Security Plan.

10-I(@) --Stock Purchase-Savings Program for Employees.

10-J(@) --Employees' Retirement Plan.

10-K(@) --Supplemental Retirement Plan.

10-L(@) --Compensation Deferral Plan.

10-M(@) --Compensation Deferral Plan for Outside Directors.

10-N(@) --Retirement Plan for Outside Directors.

10-O(@) --Supplementary Defined Contribution Plan for Employees.

10-P(@) --Directors' Charitable Giving Program.

10-Q(@) --Vacation Banking Plan.

10-R(@) --Estate Conservation Plan.

10-S(@) --Supplemental Insurance Plan.

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10-T(@) --Group Life Insurance Plan.

10-U(@) --Stock Ownership Plan for Nonemployee Directors.

* 11 --Computation of Fully Diluted Earnings Per Share (Unaudited).

* 12 --Compution of Ratio of Earnings to Fixed Charges.

* 23 --Consent of Independent Auditors.

[HARDCOPY PAGE 52]

EXHIBIT
NUMBER

* 24(a) --Power of attorney authorizing Ellen T. Ruff and others to sign the annual report on behalf of the registrant and certain of its directors and officers.

* 24(b) --Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.

@ Compensatory plan or arrangement required to be filed as an exhibit, and filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, under the same exhibit number as listed herein.

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SIGNATURES

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934, THE REGISTRANT HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED, THEREUNTO DULY AUTHORIZED, IN THE CITY OF CHARLOTTE AND STATE OF NORTH CAROLINA ON THE 29TH DAY OF

1993 COPYRIGHT SEC ONLINE, INC., 1

SEC ONLINE INC.
SCHEDULE INDEX

NUMBER	DESCRIPTION	PAGE
V	PROPERTY,PLANT AND EQUIPMENT	52
VI	ACCUMULATED DEPRECIATION OF PROPERTY,PLANT AND EQUIPMENT	53
VIII	VALUATION AND QUALIFYING ACCOUTS AND RESERVES	54
X	SUPPLEMENTARY INCOME STATEMENT INFORMATION	55

[HARDCOPY PAGE 42]

DUKE POWER COMPANY
SCHEDULE V -- PROPERTY, PLANT AND EQUIPMENT
(DOLLARS IN THOUSANDS)

DESCRIPTION	BALANCE BEGINNING OF YEAR	ADDITIONS	RETIREMENTS
FOR THE YEAR ENDED DECEMBER 31, 1993			
Electric Plant in Service -- At Original Cost			
Production	$ 6,407,161	$ 166,112	$ 66,413
Transmission	1,331,668	48,836	8,684
Distribution	3,519,235	246,482	51,188
General	871,711	65,411	19,561
Miscellaneous	64,113	(925)	24
Nuclear Fuel	718,420	158,796	171,222
Total electric plant in service	12,912,308	684,712	317,092
Construction Work in Progress	490,408	(7,935)	–

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Other Property – At Cost			
Water plant	35,655	1,554	68
Transit plant	–	–	–
Total other property	35,655	1,554	68
Total plant	$13,438,371	$ 678,331	$ 317,160
FOR THE YEAR			
ENDED DECEMBER 31, 1992			
Electric Plant in Service			
– At Original			
Cost			
Production	$ 6,228,232	$ 121,364	$ 2,521
Transmission	1,300,021	34,235	2,114
Distribution	3,335,893	236,777	53,227
General	894,685	53,114	25,046
Miscellaneous	71,380	221	174
Nuclear Fuel	2,004,441	264,506	1,448,742
Total electric plant in service	13,834,652	710,217	1,531,824
Construction Work in Progress	501,942	(11,534)	–
Other Property -- At Cost			
Water plant	35,009	830	227
Transit plant	1,499	–	1,499
Total other property	36,508	830	1,726
Total plant	$14,373,102	$ 699,513	$1,533,550
FOR THE YEAR ENDED			
DECEMBER 31, 1991			
Electric Plant in Service			
-- At Original			
Cost			
Production	$ 4,965,205	$ 1,229,905	$ 7,356
Transmission	1,223,152	80,809	2,627
Distribution	3,079,886	283,097	27,681
General	844,706	98,575	47,163
Miscellaneous	111,972	(2,229)	201
Nuclear Fuel	1,870,975	133,466	–
Total electric plant in service	12,095,896	1,823,623	85,028
Construction Work in Progress	1,521,391	(1,019,449)	–
Other Property -- At Cost			
Water plant	33,886	1,312	189
Transit plant	2,782	–	1,283
Total other property	36,668	1,312	1,472
Total plant	$13,653,955	$ 805,486	$ 86,500

(TABLE CONTINUED)

DESCRIPTION	ADD	BALANCE END (DEDUCT)	OF YEAR
FOR THE YEAR ENDED			
DECEMBER 31, 1993			
Electric Plant in			
Service -- At Original Cost			

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Production	$ 13,903	$ 6,520,763
Transmission	(3,696)	1,368,124
Distribution	3,133	3,717,662
General	(1,461)	916,100
Miscellaneous	(12,801)	50,363
Nuclear Fuel	–	705,994
Total electric plant in service	(922)	13,279,006
Construction Work in Progress	–	482,473
Other Property – At Cost		
Water plant	–	37,141
Transit plant	–	–
Total other property	–	37,141
Total plant	$ (922)	$13,798,620
FOR THE YEAR		
ENDED DECEMBER 31, 1992		
Electric Plant in Service		
– At Original		
Cost		
Production	$ 60,086	$ 6,407,161
Transmission	(474)	1,331,668
Distribution	(208)	3,519,235
General	(51,042)	871,711
Miscellaneous	(7,314)	64,113
Nuclear Fuel	(101,785)	718,420
Total electric plant in service	(100,737)	12,912,308
Construction Work in Progress	–	490,408
Other Property -- At Cost		
Water plant	43	35,655
Transit plant	–	–
Total other property	43	35,655
Total plant	$ (100,694)	$13,438,371
FOR THE YEAR ENDED		
DECEMBER 31, 1991		
Electric Plant in Service		
– At Original		
Cost		
Production	$ 40,478	$ 6,228,232
Transmission	(1,313)	1,300,021
Distribution	591	3,335,893
General	(1,433)	894,685
Miscellaneous	(38,162)	71,380
Nuclear Fuel	–	2,004,441
Total electric plant in service	161	13,834,652
Construction Work in Progress	–	501,942
Other Property – At Cost		
Water plant	–	35,009
Transit plant	–	1,499
Total other property	–	36,508
Total plant	$ 161	$14,373,102

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[HARDCOPY PAGE 43]

DUKE POWER COMPANY
SCHEDULE VI -- ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT
(DOLLARS IN THOUSANDS)

DESCRIPTION	BALANCE BEGINNING OF YEAR	CLEARING AND DEPRECIATION	OTHER ACCOUNTS
FOR THE YEAR ENDED DECEMBER 31, 1993			
Accumulated Depreciation of Electric Plant			
Production	$2,328,319	$232,937	$ --
Transmission	561,068	33,527	--
Distribution	1,053,408	129,665	--
General	242,694	25,375	4,830
Miscellaneous	5,537	--	359
	4,191,026	421,504	5,189
Accumulated Amortization of Limited Term Plant	6,479	--	511
Accumulated Amortization of Nuclear Fuel	425,088	--	152,045
	4,622,593	421,504	157,745
Accumulated Depreciation of Water Plant	8,586	710	--
Total Accumulated Depreciation	$4,631,179	$422,214	$157,745
FOR THE YEAR ENDED DECEMBER 31, 1992			
Accumulated Depreciation of Electric Plant			
Production	$2,119,391	$226,137	$ --
Transmission	531,332	33,213	--
Distribution	979,805	122,311	--
General	229,400	26,612	4,758
Miscellaneous	49,850	--	357

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	3,909,778	408,273	5,115
Accumulated Amortization of Limited Term Plant	5,983	–	687
Accumulated Amortization of Nuclear Fuel	1,722,192	–	151,638
	5,637,953	408,273	157,440
Accumulated Depreciation of Water Plant	8,094	691	–
Accumulated Depreciation of Transit Plant	1,420	2	–
Total Accumulated Depreciation	$5,647,467	$408,966	$157,440
FOR THE YEAR ENDED DECEMBER 31, 1991			
Accumulated Depreciation of Electric Plant			
Production	$1,902,284	$198,372	$ –
Transmission	500,555	34,589	–
Distribution	896,226	109,461	–
General	221,691	30,920	13,393
Miscellaneous	88,258	–	352
	3,609,014	373,342	13,745
Accumulated Amortization of Limited Term Plant	5,108	–	497
Accumulated Amortization of Nuclear Fuel	1,552,977	–	169,215
	5,167,099	373,342	183,457
Accumulated Depreciation of Water Plant	7,578	682	–
Accumulated Depreciation of Transit Plant	2,662	41	–
Total Accumulated Depreciation	$5,177,339	$374,065	$183,457

(TABLE CONTINUED)

DESCRIPTION	RETIREMENTS	OTHER CHANGES ADD (DEDUCT)	BALANCE END OF YEAR
FOR THE YEAR ENDED DECEMBER 31, 1993			
Accumulated Depreciation of Electric Plant			
Production	$ 72,453	$ (49,675)	$2,439,128
Transmission	6,703	3,843	591,735
Distribution	47,387	(4,097)	1,131,589
General	14,194	(2,595)	256,110
Miscellaneous	–	–	5,896

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	140,737	(52,524)	4,424,458
Accumulated Amortization of Limited Term Plant	(11)	–	7,001
Accumulated Amortization of Nuclear Fuel	171,222	–	405,911
	311,948	(52,524)	4,837,370
Accumulated Depreciation of Water Plant	63	–	9,233
Total Accumulated Depreciation	$ 312,011	$ (52,524)	$4,846,603
FOR THE YEAR ENDED DECEMBER 31, 1992			
Accumulated Depreciation of Electric Plant			
Production	$ 11,572	$ (5,637)	$2,328,319
Transmission	3,208	(269)	561,068
Distribution	49,127	419	1,053,408
General	18,929	853	242,694
Miscellaneous	–	(44,670)	5,537
	82,836	(49,304)	4,191,026
Accumulated Amortization of Limited Term Plant	4	(187)	6,479
Accumulated Amortization of Nuclear Fuel	1,448,742	–	425,088
	1,531,582	(49,491)	4,622,593
Accumulated Depreciation of Water Plant	221	22	8,586
Accumulated Depreciation of Transit Plant	1,449	27	–
Total Accumulated Depreciation	$1,533,252	$ (49,442)	$4,631,179
FOR THE YEAR ENDED DECEMBER 31, 1991			
Accumulated Depreciation of Electric Plant			
Production	$ 13,054	$31,789	$2,119,391
Transmission	2,901	(911)	531,332
Distribution	26,787	905	979,805
General	35,269	(1,335)	229,400
Miscellaneous	--	(38,760)	49,850
	78,011	(8,312)	3,909,778
Accumulated Amortization of Limited Term Plant	–	378	5,983
Accumulated Amortization of Nuclear Fuel	–	–	1,722,192
	78,011	(7,934)	5,637,953
Accumulated Depreciation			

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of Water Plant	166	--	8,094
Accumulated Depreciation of Transit Plant	1,283	--	1,420
Total Accumulated Depreciation	$ 79,460	$ (7,934)	$5,647,467

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DUKE POWER COMPANY
SCHEDULE VIII -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
(DOLLARS IN THOUSANDS)

DESCRIPTION	BALANCE BEGINNING OF YEAR	BALANCE END OF YEAR
FOR THE YEAR ENDED DECEMBER 31, 1993		
Reserves Related to Assets on Balance Sheet	$10,730	$ 10,353
Other Reserves		
Operating Reserves (1)	$78,103	$107,477
FOR THE YEAR ENDED DECEMBER 31, 1992		
Reserves Related to Assets on Balance Sheet	$25,592	$ 10,730
Other Reserves		
Operating Reserves (1)	$67,577	$ 78,103
FOR THE YEAR ENDED DECEMBER 31, 1991		
Reserves Related to Assets on Balance Sheet	$43,712	$ 25,592
Other Reserves		
Operating Reserves (1)	$59,527	$ 67,577

(1) Principally consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred credits and other liabilities" in the Consolidated Balance Sheets.

[HARDCOPY PAGE SCH1]

SCHEDULE X -- SUPPLEMENTARY CONSOLIDATED INCOME STATEMENT INFORMATION

1993 COPYRIGHT SEC ONLINE, INC., 1

	YEAR ENDED DECEMBER 31,		
	1993	1992	1991
	(DOLLARS IN THOUSANDS)		
Taxes, other than payroll and income taxes			
Real and personal property	$ 88,725	$ 82,327	$ 68,117
State and city franchise	91,494	84,033	89,307
Other	11,669	11,663	12,531
Total	$191,888	$178,023	$169,955

SEC ONLINE INC.
EXHIBIT INDEX

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[HARDCOPY PAGE EXH1]

EXHIBIT 11 DUKE POWER COMPANY
COMPUTATION OF FULLY DILUTED EARNINGS PER SHARE –
(UNAUDITED)

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This calculation is submitted in accordance with Regulation S-K under the Securities Exchange Act of 1934, although not required by footnote 2 to paragraph 14 of Opinion No. 15 of the Accounting Principles Board because it results in dilution of less than 3%.

	YEAR ENDED DECEMBER 31		
	1993	1992	1991
	(DOLLARS IN THOUSANDS EXCEPT PER SHARE FIGURES)		
Fully Diluted:			
Earnings applicable to common stock (1)	$573,986	$451,676	$528,940
Add: Dividends on Preference Stock, 6 3/4% Convertible Series AA	–	–	140
Earnings as adjusted for computation	$573,986	$451,676	$529,080
Average common shares outstanding – twelve months (thousands)(1)	204,859	204,819	203,431
Add: Common shares required for conversion of Preference Stock, 6 3/4% Convertible Series AA, $100 par, 500,000 shares authorized (no shares outstanding as of December 31, 1992 & 1993)(2)	–	–	169
Common shares as adjusted for computation (thousands)	204,859	204,819	203,600
Fully diluted earnings per share	$ 2.80	$ 2.21	$ 2.60

(1) These figures agree with the related amounts in the Consolidated Statements of Income.

(2) All shares were converted in April 1992. The conversion price used to convert the Preference Stock, 6 3/4% Convertible Series AA, into shares of common stock was $11.95.

[HARDCOPY PAGE EXH2]

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EXHIBIT 12

DUKE POWER COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(DOLLARS IN THOUSANDS)

	YEAR ENDED DECEMBER 31		
	1993	1992	1991
Earnings Before Income Taxes	$1,037,096	$ 811,401	$ 879,766
Fixed Charges	281,821	327,308	308,862
Total	$1,318,917	$1,138,709	$1,188,628
Fixed Charges			
Interest on long-term debt	243,047	257,149	269,419
Other interest	18,098	47,972	22,780
Amortization of debt discount, premium and expense	13,300	8,497	5,242
Interest component of rentals	7,376	13,690	11,421
Fixed Charges	$ 281,821	$ 327,308	$ 308,862
Ratio of Earnings to Fixed Charges	4.68	3.48	3.85

(TABLE CONTINUED)

	YEAR ENDED DECEMBER 31	
	1990	1989
Earnings Before Income Taxes	$ 790,546	$ 867,641
Fixed Charges	297,116	266,497
Total	$1,087,662	$1,134,138
Fixed Charges		
Interest on long-term debt	255,334	232,510
Other interest	24,306	18,203
Amortization of debt discount, premium and expense	4,998	4,677
Interest component of rentals	12,478	11,107
Fixed Charges	$ 297,116	$ 266,497
Ratio of Earnings to Fixed Charges	3.66	4.26

[HARDCOPY PAGE EXH3]

EXHIBIT 23

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CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 33-59926, 33-60314, 33-19274, 33-50543, 33-50715, 33-50617 and 33-52479 of Duke Power Company on Form S-3 and Registration Statement No. 2-72172 of Duke Power Company on Form S-8 of our report dated February 11, 1994, appearing in this Form 10-K of Duke Power Company for the year ended December 31, 1993.

DELOITTE & TOUCHE
DELOITTE & TOUCHE

Charlotte, North Carolina
March 29, 1994

[HARDCOPY PAGE EXH4]

Exhibit 24(a) DUKE POWER COMPANY
Power of Attorney

FORM 10-K

Annual Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 1993

(Annual Report)

The undersigned, DUKE POWER COMPANY, a North Carolina corporation, and certain of its officers and/or directors, do each hereby constitute and appoint W. S. Lee, Richard J. Osborne, Ellen T. Ruff, David L. Hauser, and each of them, to act as attorneys-in-fact for and in the respective names, places and stead of the undersigned, to execute, seal, sign and file with the Securities and Exchange Commission the Annual Report of said Duke Power Company on Form 10-K and any and all amendments thereto, hereby granting to said attorneys-in-fact, and each of them, full power and authority to do and perform all and every act and thing whatsoever requisite, necessary or proper to be done in and about the premises, as fully to all intents and purposes as the undersigned, or any of them, might or could do if personally present, hereby ratifying and approving the acts of said attorneys-in-fact.

Executed the 22nd day of February, 1994.

DUKE POWER COMPANY

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By W.S. Lee

Chairman and President

(Corporate Seal)

ATTEST:

Carolyn R. Duncan

Assistant Secretary

[HARDCOPY PAGE EXH5]

W.S. Lee — Chairman and President (Principal Executive Officer and Director)

W.S. Lee

Richard J. Osborne — Vice President and Chief Financial Officer (Principal Financial Officer)

Richard J. Osborne

David L. Hauser — Controller (Principal Accounting Officer)

David L. Hauser

Robert L. Albright (Director)

Robert L. Albright

G. Alex Bernhardt (Director)

G. Alex Bernhardt

Crandall C. Bowles (Director)

Crandall C. Bowles

William A. Coley (Director)

William A. Coley

Joe T. Ford (Director)

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Joe T. Ford

Steve C. Griffith, Jr. (Director)

Steve C. Griffith, Jr.

W.H. Grigg (Director)

W.H. Grigg

Paul H. Henson (Director)

Paul H. Henson

George R. Herbert (Director)

George R. Herbert

(Director)

George Dean Johnson, Jr.

James V. Johnson (Director)

James V. Johnson

W.W. Johnson (Director)

W.W. Johnson

Max Lennon (Director)

Max Lennon

Buck Mickel (Director)

Buck Mickel

Reece A. Overcash, Jr. (Director)

Reece A. Overcash, Jr.

Richard B. Priory (Director)

Richard B. Priory

[HARDCOPY PAGE EXH6]

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EXHIBIT 24(b)
EXTRACT FROM THE MINUTES OF A MEETING
OF THE BOARD OF DIRECTORS OF DUKE POWER COMPANY
HELD ON FEBRUARY 22, 1994

Mr. Lee then referred to the Company's Form 10-K Annual Report. He presented to the meeting a preliminary copy of the Form 10-K, indicating that it would be in order to approve such document subject to such changes as may be deemed necessary or advisable. Dr. Herbert then advised that the Audit Committee had reviewed the Form 10-K and found it to be in order and recommended its approval. Upon motion duly made and seconded, it was

RESOLVED, That the Form 10-K Annual Report, as presented to the meeting, with such changes therein as may be deemed necessary or advisable by the officers of the Company be and hereby is in all respects approved; and

FURTHER RESOLVED, That the Power of Attorney as presented to the meeting and executed by all the Directors present be and hereby is approved in form and content for purposes of filing the Form 10-K Annual Report with the Securities and Exchange Commission.

I, ELLEN T. RUFF, Secretary of Duke Power Company, do hereby certify that the foregoing is a full, true, and complete extract from the minutes of the meeting of the Board of Directors of said Company held on February 22, 1994, containing all resolutions adopted with respect to the Form 10-K, at which meeting a quorum was present.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the corporate seal of said DUKE POWER COMPANY, this 29th day of March, 1994.

Ellen T. Ruff

Secretary

(SEAL)

APPENDIX

On Page 12 there is a full-page map of the Duke Power Service Area, showing the locations of the Company's region offices, steam electric

1993 COPYRIGHT SEC ONLINE, INC., 1

stations, hydroelectric stations, nuclear electric stations and Nantahala Power and Light Company. Such page also includes a smaller inset map showing the Company's service area, along with the service area of Nantahala Power and Light Company, superimposed over an outline map of the states of North Carolina and South Carolina.

LENGTH: 44479 words

LOAD-DATE: May 6, 1994

LANGUAGE: ENGLISH

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10-K

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DUKE POWER CO
TICKER-SYMBOL: DUK EXCHANGE: NYS

422 SOUTH CHURCH STREET
CHARLOTTE, NC 28242
704-373-4011

INCORPORATION: NC

COMPANY-NUMBER: FORBES NUMBER: SA229
CUSIP NUMBER: 26439910
DUNS NUMBER: 00-699-6052
COMMISSION FILE NO.: 1-4928
IRS-ID: 56-0205520

SIC: SIC-CODES: 4911, 4941
PRIMARY SIC: 4911

INDUSTRY-CLASS: ELECTRIC SERVICES

FYE: 12/31

AUDITOR: DELOITTE & TOUCHE

STOCK-AGENT: FIRST UNION NATIONAL BANK

COUNSEL: STEVE C. GRIFFITH - GENERAL COUNSEL

INVESTOR-CONTACT: ALLEN J. STEWART - INVESTOR RELATIONS

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DUKE POWER COMPANY
FORM 10-K
ANNUAL REPORT TO
THE SECURITIES AND EXCHANGE COMMISSION
FOR THE YEAR ENDED DECEMBER 31, 1994

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DUKE POWER COMPANY

PART I.

Item 1. ***Business.***

Duke Power Company (the Company) is primarily engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas. It is one of the nation's largest investor-owned electric utilities.

The Company is also engaged in a variety of diversified operations, most of which are organized in separate subsidiaries. During 1994, the Company reorganized, placing all its subsidiaries and diversified activities except for the core electric utility business into the Associated Enterprises Group (AEG). AEG includes Church Street Capital Corp.; Crescent Resources, Inc.; Duke Energy Group, Inc.; Duke Engineering & Services, Inc.; Duke/Fluor Daniel; Duke Merchandising; DukeNet Communications, Inc.; Duke Water Operations; and Nantahala Power and Light Company (NP&L). For additional information on subsidiaries and diversified activities, see "Subsidiaries and Diversified Activities" on page 9, "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — Subsidiaries and Diversified Activities" on page 22 and "Subsidiaries and Diversified Activities Highlights" on page 46.

During 1994, the Company's operating revenues, including AEG, were $4.5 billion. The Company's executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242-0001 (Telephone No. 704-594-0887).

Service Area

The Company's service area (excluding NP&L), approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4.9 million and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville and Spartanburg in South Carolina. The Company supplies electric service directly to approximately 1.7 million residential, commercial and industrial customers in more than 200 cities, towns and unincorporated communities. Electricity is sold at wholesale to incorporated municipalities and to several public and private utilities. In addition, in 1994 approximately 8% of total sales were made through contractual agreements to former wholesale municipal or cooperative customers of the Company who had purchased portions of the Catawba Nuclear Station (collectively, the "Other Catawba Joint Owners") (See "Joint Ownership of Generating Facilities.") NP&L services an additional 53,000 mostly residential customers in five counties in western North Carolina.

The Company's service area is undergoing increasingly diversified industrial development. The textile, manufacture of machinery and equipment, and chemical and chemical related industries are of major significance to the economy of the area. Other industrial activity includes the rubber and plastic products, paper and allied products, and various other light and heavy manufacturing and service businesses. The largest industry served is the textile industry, which accounted for approximately $498 million of the Company's revenues for 1994, representing 12 percent of electric revenues and 40 percent of industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability at December 31, 1994, its sources of electric energy for 1994, and certain information presently projected for 1995:

Source	Generating Capability — KW(a)(b)(c)		Generation — KWH (millions)(c)
	Actual December 31, 1994	Projected December 31, 1995	Actual 1994
Coal	7,661,000	7,699,000(d)	32,714
Nuclear (e)	7,054,000	7,054,000	50,887
Hydro and other	3,266,000	4,154,000(f)	1,495
Total	17,981,000	18,907,000	85,096
Less: Other Catawba Joint Owners' share			15,300
Plus: Purchases from Other Catawba Joint Owners			9,046
Purchased power and net interchange			1,276
Total			80,118

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(a) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(b) Excludes firm purchases. (See "Energy Management and Future Power Needs.")

(c) Excludes NP&L.

(d) Includes the 38,000 KW fossil unit returned to service from the Plant Modernization Program on January 1, 1995.

(e) Nuclear capability and related generation for 1994 and projected for 1995 give no effect to the joint ownership of the Catawba Nuclear Station. (See "Joint Ownership of Generating Facilities.")

(f) Includes 12 units of the Lincoln Combustion Turbine Station with generating capacity of 888,000 KW scheduled to begin commercial operation in 1995. Four additional units with generating capacity of 296,000 KW are scheduled to begin commercial operation in 1996. (See "Capital Requirements.")

NP&L operates 11 hydroelectric stations with a total capacity of 100,000 kilowatts, and also buys supplemental power. The Company supplies supplemental power to NP&L under the terms of an interconnection agreement approved by the Federal Energy Regulatory Commission (FERC).

The Company has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power agreement.

According to 1993 industry statistics published in 1994, the Company ranked first in the nation in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Published rankings indicate that individual units at Marshall Steam Station and Belews Creek Steam Station ranked first, third, fifth, eighth and tenth most efficient in the nation in 1993. The Company's nuclear system continued its tradition of operating efficiency, operating at 82 percent of capacity for 1994, in comparison with the industry's most current average capacity factor of 71 percent for 1993.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The Company currently forecasts a 2.1 percent compound annual growth in peak load through 2009. An all-time peak load of 16,070,000 KW occurred on January 19, 1994 during extremely cold winter weather.

Rate Matters

The North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC) must approve the Company's rates for retail sales within their respective states. FERC must approve the Company's rates for sales to wholesale customers, including the contractual arrangements between the Company and the Other Catawba Joint Owners.

Rate requests filed by the Company in its most recent general rate case in 1991 with the NCUC, PSCSC and FERC were principally designed to reflect the Company's investment in the Bad Creek Hydroelectric Station. Rate orders issued by the NCUC and PSCSC in November 1991 recognized costs of the Bad Creek Hydroelectric Station, including an amortization of costs deferred between commercial operation and the rate order, which the Company had requested. The Company's wholesale customers challenged its proposed rate increase and in 1991 FERC issued an order that accepted the Company's proposed rates for filing. A negotiated settlement with these customers, which provided for an increase in wholesale rates consistent with the increase in retail rates, was approved by FERC and became effective in April 1992. (See Note 2, "Notes to Consolidated Financial Statements.")

In its most recent general rate case, the NCUC authorized a jurisdictional rate of return on common equity of 12.50 percent and the PSCSC authorized a jurisdictional rate of return on common equity of 12.25 percent.

In 1992, the North Carolina Supreme Court remanded to the NCUC the Company's 1986 rate order for the second time. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order in 1992 which resulted in a 1992 refund to North Carolina retail customers of approximately $95 million, including interest.

During 1992, NP&L filed an application for a general rate increase with the NCUC. A general rate increase was approved in June 1993.

Fuel and Purchased Power Cost Adjustment Procedures. Duke Power has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The NCUC ordered Duke Power to follow these procedures in its August 1986 order, which was effective for periods beginning January 1, 1986. The prospective adjustment in rates of past over- or under-recovery of fuel costs was challenged in the North Carolina courts. The North Carolina legislature ratified a bill in July 1987 assuring the legality of such adjustments in rates. In 1991, the statute was extended through June 30, 1997. In the North Carolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings. Fuel costs are reviewed semiannually in the wholesale and South Carolina retail jurisdictions.

All jurisdictions allow Duke Power to adjust rates for over- or under-recovery of fuel costs. Therefore, Duke Power reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

Construction Work in Progress (CWIP). The NCUC is permitted in its discretion to include CWIP in rate base after giving consideration to the public interest and the Company's financial stability. The PSCSC may include CWIP in rate base in its discretion.

Energy Management and Future Power Needs

The Company's strategy for meeting customers' present and future energy needs is composed of three components: demand-side resources, purchased power resources and supply-side resources. By utilizing these resources, the Company expects to maintain a reserve margin of approximately 17 to 23 percent of its anticipated peak load requirements through 1999.

Demand-side management programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The Company ultimately expects recovery through rates of associated deferred costs. The annual costs deferred, including the return, were approximately $25 million in 1994 and $26 million in 1993.

The Company continues to engage in a comprehensive energy management program as part of its Integrated Resource Plan. Integrated Resource Planning is the process used by utilities to evaluate a variety of resources. The goal is to provide adequate and reliable electricity in an environmentally responsible manner through cost-effective power management.

In January 1993, the PSCSC issued an order approving the Company's 1992 Integrated Resource Plan as reasonable, and approving a "shared savings" proposal for accomplishments made in the Company's demand-side management programs. In June 1993, the NCUC approved the 1992 plan, including the shared savings mechanism. The Integrated Resource Plan is filed every three years. Each of the other years, the Company files a Short Term Action Plan which updates the Integrated Resource Plan for any changes in projections for the next three years.

The purchase of capacity and energy is also an integral part of meeting future power needs. As of January 1, 1995, the Company has under contract 300 megawatts of capacity from other generators of electricity, including 62 megawatts from qualifying facilities. The Company expects to use a competitive bidding process to provide for the next increment of generating capacity beyond the Lincoln Combustion Turbine Station.

Capital Requirements

Projected capital expenditures, excluding costs related to portions of the Catawba Nuclear Station owned by the Other Catawba Joint Owners, for each of 1995, 1996, 1997, 1998 and 1999 and for the five-year period 1995-1999, as now scheduled, are as follows (in millions of dollars):

	1995	1996	1997	1998	1999	Total
Duke Power — Electric						
Generation	$332	$205	$261	$228	$322	$1,348
Transmission	42	44	45	47	48	226
Distribution	202	210	218	221	223	1,074
Other	93	77	67	72	73	382
Nuclear Fuel	104	103	158	123	132	620
Total	$773	$639	$749	$691	$798	$3,650
Associated Enterprises Group	$166	$137	$112	$101	$145	$ 661
Total Company	$939	$776	$861	$792	$943	$4,311

The Company's procedures for estimating capital expenditures (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs, allowances for inflation and the Company's business plan, which includes the expansion of the business activities of AEG. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

The Company is building a combustion turbine facility in Lincoln County, North Carolina to provide capacity at periods of peak demand. The Lincoln Combustion Turbine Station will consist of 16 combustion turbines with a total generating capacity of 1,184 megawatts. The estimated total cost of the project is approximately $500 million. Current plans are for 12 units to begin commercial operation by the end of 1995 and the remaining four to begin commercial operation in 1996. During 1991, the NCUC granted the Certificate of Public Convenience and Necessity and the North Carolina Division of Environmental Management issued a final air permit for the facility. The issuance of the final air permit for the facility was appealed, and one of the two appeals was settled and dismissed in March 1995. The other appeal has not been pursued by the appellant and is expected to be dismissed during the second quarter of 1995.

Joint Ownership of Generating Facilities

In order to reduce its need for external financing, the Company, through several transactions beginning in 1978, sold an 87½ percent undivided interest in the Catawba Nuclear Station to the Other Catawba Joint Owners.

These transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use (whether or not the facility is generating electricity) that portion of the capacity not then contractually required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The transactions also include a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station of the Company, which provides for an exchange of 50 percent of each Other Catawba Joint Owner's retained capacity from its ownership interest in the Catawba units for like amounts of capability and output from units of the McGuire Nuclear Station. The implementation of the reliability exchange has not had nor does the Company anticipate that such implementation will have a material effect on earnings. (See Note 3, "Notes to Consolidated Financial Statements.")

The Other Catawba Joint Owners and the Company were involved in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the Other Catawba Joint Owners which have been previously approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3, "Notes to Consolidated Financial Statements.") The Company and the Other Catawba Joint Owners entered into settlement agreements in 1994 which resolved all issues in contention in the proceedings. The Company has settled its cumulative net obligation through 1993 of approximately $205 million with the Other Catawba Joint Owners. Billings for 1994 and later years will conform to the settlement agreements,

which have been approved by the Company's retail regulatory commissions. Because it expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, the Company has included approximately $205 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Fuel Supply

The Company presently relies principally on nuclear fuel and coal for the generation of electric energy. The Company's reliance on oil and gas is minimal and will remain minimal even with the addition of the Lincoln Combustion Turbine Station.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

	Generation by Source Year Ended December 31			Cost of Fuel per Net KWH Generated (Cents) Year Ended December 31		
	1994	1993	1992	1994	1993	1992
Coal	38.5%	40.6%	36.7%	1.54	1.61	1.65
Nuclear	59.8	57.5	61.0	.56	.54	.54
Oil and Gas	—	—	—	—	—	—
All Fuels (cost based on weighted average)	98.3	98.1	97.7	.95	.99	.96
Hydroelectric(1)	1.7	1.9	2.3			
	100.0%	100.0%	100.0%			

(1) Generating figures are net of that output required to replenish pumped storage units during off-peak periods. Does not include NP&L.

Coal. The Company obtains a large amount of its coal under long-term supply contracts with mining operators utilizing both underground and surface mining. The Company has on hand an adequate supply of coal.

The Company's long-term supply contracts, all of which have price adjustment provisions, have expiration dates ranging from 1995 to 2003. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers for quantities and qualities of coal required. However, due to the Clean Air Act Amendments of 1990, fuel premiums may be required as contracts are renewed. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. The Company's short-term requirements have been and will be fulfilled with spot market purchases. The average sulfur content of coal being purchased by the Company is approximately 1 percent. Such coal satisfies the current emission limitation for sulfur dioxide for existing facilities. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — The Clean Air Act Amendments of 1990.")

Nuclear. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations. Based upon current projections, these contracts will meet the Company's requirements through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1997	1998	2000	2006
McGuire	1997	1998	2000	2009
Catawba	1997	1998	2000	2009

Uranium material requirements will be met through various supplier contracts, with uranium material produced primarily in the U.S., Canada and Australia. The Company believes that it will be able to renew contracts as they expire or to enter into similar contractual arrangements with other nuclear fuel materials and services suppliers. Short-term requirements have been and will be fulfilled with uranium spot market purchases.

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The Nuclear Waste Policy Act of 1982 requires that the Department of Energy (DOE) begin disposing of spent fuel no later than January 31, 1998. The Company has entered into the required contracts with the DOE for the disposal of nuclear fuel and began making payments in July 1983 for disposal costs of fuel currently being utilized. These payments, combined with a one-time payment for disposal costs of fuel consumed prior to April 7, 1983, have totaled about $563 million through 1994. In November 1989, the DOE released a report which indicated that it expects that a facility for spent fuel disposal will not be available until the year 2010. The DOE continues to pursue a centralized interim storage facility, with a target operation date of 1998, for earlier acceptance of spent fuel from utilities. The Company believes that it will be able to provide adequate on-system storage capacity until such time as the DOE begins receiving spent fuel.

Regulation

The Company is subject to the jurisdiction of the NCUC and the PSCSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC, the Environmental Protection Agency (EPA) and state environmental agencies and to the jurisdiction of the Nuclear Regulatory Commission (NRC) as to design, construction and operation of its nuclear power facilities. The Company is exempt from regulation as a holding company under the Public Utility Holding Company Act of 1935, except with respect to the acquisition of the securities of other public utilities.

Environmental Matters. The Company is subject to federal, state, and local regulations with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. North Carolina has enacted a declaration of environmental policy requiring all state agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. South Carolina law also requires consideration by the PSCSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed major utility facilities, which include certain generation and transmission facilities. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. In 1994, the Company's construction costs for environmental protection totaled approximately $22 million, while the on-going environmental operation costs were approximately $25 million. The Company's 1995-1999 construction program includes costs for environmental protection which are estimated to be approximately $50 million, including $18.1 million in 1995, $8.5 million in 1996, $6.6 million in 1997, $8.6 million in 1998 and $8.5 million in 1999. These costs include expenditures associated with the Clean Air Act Amendments of 1990. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. These projections are subject to periodic review and revisions. Actual construction costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including cost and availability of capital.

AIR QUALITY. See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — The Clean Air Act Amendments of 1990" for a discussion of the Company's plans for compliance with federal clean air standards.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1987 (otherwise known as the "Clean Water Act") require permits for facilities that discharge into waters, to ensure compliance with its provisions. The Company holds numerous such permits and such permits are reissued periodically. The Clean Water Act was scheduled for reauthorization by Congress in 1994. Congress did not act to reauthorize the Clean Water Act in 1994, but it is likely that action will be taken on such reauthorization in 1995. Until Congress acts upon the reauthorization, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

OTHER ENVIRONMENTAL REGULATIONS. Contingencies associated with environmental matters are principally related to possible obligations to remove or mitigate the effects on the environment resulting from the disposal of certain substances at contamination sites.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as "Superfund", requires any individual or entity which may have owned or operated a contaminated site, as well as transporters or generators of hazardous wastes which were sent to such site, to assume joint and several responsibility for remediation of the site. Such parties are known as "potentially responsible parties" (PRPs). The Company is currently participating in PRP groups with regard to Superfund sites in Concord, North Carolina, and two sites in Pennsylvania. The Company is a PRP at a contamination site in Charlotte, North Carolina which is being remediated in accordance with a state act similar to CERCLA.

The Company is also a PRP at a site in Lenoir, North Carolina which will likely be remediated in accordance with federal or state law. In addition, the Company has agreed to remediate a small volume of PCB-contaminated soil at a site in Chester, South Carolina. While the total cost of remediation at these federal and state contamination sites may be substantial, the Company shares probable liability with other PRPs, many of which have substantial assets. Other contamination sites arise from the Company's operation of manufactured gas plant (MGP) sites until the early 1950's, some of which are still owned by the Company and some of which are now owned by third parties. In North Carolina, the Company is participating in a state-sponsored program to investigate and, where appropriate, remediate MGP sites. The State of South Carolina has expressed interest in entering into a similar arrangement. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

CERCLA was scheduled for reauthorization by Congress in 1994. An administration bill to reform CERCLA was acted upon by several Senate and House committees, but was never voted upon by either body. While CERCLA reform is likely to be acted upon by Congress in 1995, until such action occurs, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

GENERAL. Over the past few decades, the issue of the possible health effects of electric and magnetic fields has generated a number of generally inconclusive studies, some public concern and litigation as well as legislative action in some states regarding high voltage transmission lines. The impact of this issue on the Company cannot presently be determined.

Nuclear Facilities. The Company's nuclear facilities are subject to continuing regulation by the NRC.

Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company is planning for the replacement of steam generators at three units that have experienced SCC and has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. The current schedule for completion of the effort is as follows: Catawba Unit 1 — 1996, McGuire Unit 1 — 1997 and McGuire Unit 2 — 1997. The order of replacement is subject to change based on operational and project circumstances. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $170 million per unit, excluding the cost of replacement power and the reimbursement of applicable costs by the Other Catawba Joint Owners for Catawba Unit 1. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the Other Catawba Joint Owners, began a legal action on March 22, 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba Stations steam generators that were defective in design, workmanship and materials, requiring replacement well short of their stated design life. On March 17, 1994, the Company together with the Other Catawba Joint Owners, settled the lawsuit. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the results of operations or financial position of the Company.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The Other Catawba Joint Owners are responsible for decommissioning costs related to their ownership interest in the station. Both the NCUC and the PSCSC have granted the Company recovery of the estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume that units will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021, McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The NRC issued a rulemaking in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1994, the Company expensed approximately $52.5 million which was contributed to the external funds and accrued an additional $4.8 million to the internal reserve. The balance of the external funds as of December 31, 1994, was $172.4 million. The balance of the internal reserve as of December 31, 1994, was $204.8 million and is reflected

in Accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid approximately $18 million during 1994 and $26.3 million cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of approximately $102 million in the Consolidated Balance Sheets at December 31, 1994.

Nuclear Insurance. For a discussion of the Company's nuclear insurance coverage, see "Note 13, Notes to Consolidated Financial Statements, Commitments and Contingencies — Nuclear Insurance."

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for the Keowee-Toxaway Project for a term expiring in 2016, covering the Keowee Hydro Station and the Jocassee Pumped Storage Station for a combined total of 769,500 KW, on the upper tributaries of the Savannah River in northwestern South Carolina. Additionally, the Company is the licensee through 2027 for the Bad Creek Hydroelectric Station which uses Lake Jocassee as its lower reservoir and has a nameplate rating of 1,065,000 KW. NP&L holds licenses for 11 hydroelectric projects with a nameplate rating of 100,000 KW with license terms expiring 2001-2006. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

The Company has major interconnections and arrangements with its neighboring utilities which it currently considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

Competition

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems, rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSCSC, respectively, of all areas outside municipalities in such states to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSCSC. In addition, the Company is engaged in continuing competition with various natural gas providers.

The Energy Policy Act of 1992 (EPACT) is moving utilities toward a more competitive environment. The EPACT reformed certain provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain regulatory barriers. For example, the EPACT allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. The EPACT requires transmission of power for third parties to wholesale customers on issuance of an order by the FERC, provided the reliability of service to the utility's local customer base is protected and the local customer base does not subsidize the third-party service. The EPACT does not permit the FERC to issue an order requiring transmission access to retail customers.

The electric utility industry currently is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based price of electricity, profits could be reduced and utilities might be

required to reduce their recorded asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation could also require some utilities to write off their regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are regionally and nationally competitive. The Company filed an open access transmission tariff with the FERC in early 1995 (See "Subsequent Events").

Subsidiaries and Diversified Activities

The Company continues to pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Although these opportunities are concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. (See "Subsidiaries and Diversified Activities Highlights" on page 46.)

Crescent Resources, Inc. (Crescent) pursues both residential and commercial real estate development, in addition to providing forest management activities focused on growing trees suitable for use in the construction, furniture and paper industries. At December 31, 1994, Crescent owned approximately 2,223,000 square feet of office, retail and warehouse space and had approximately 818,000 square feet of commercial properties under construction. Additionally, Crescent had approximately 266,000 acres of land under its management at year end.

Duke Energy Group, Inc. (Duke Energy) develops, owns and operates electric power-related facilities in the United States and abroad. Domestically, Duke Energy concentrates on advanced fossil-fueled generation including pulverized coal, circulating fluidized bed, coal gasification and natural gas technologies. Internationally, Duke Energy pursues advanced coal-fueled, hydroelectric and gas-fueled generation as well as transmission projects. Duke Energy has equity interests in two U.S. electric generation facilities and four international projects.

In 1994, Duke Energy announced plans to participate in power marketing activities in North America with Louis Dreyfus Electric Power (LDEP), following regulatory approvals. LDEP is currently the largest power marketer in the United States. (See "Subsequent Events.")

Nantahala Power and Light Company (NP&L) is a franchised electric utility which operates 11 hydroelectric plants with a total capacity of 100,000 kilowatts. NP&L has approximately 53,000 customers in western North Carolina. NP&L sold 907 million KWH in 1994 compared to 889 million KWH in 1993, excluding sales to Duke Power.

Other Business Units include Church Street Capital Corp., which is engaged in investment management for its subsidiaries; Duke Engineering & Services, Inc., which markets engineering, construction, quality assurance, consulting and other engineering-related services for facilities other than coal-fired generating plants, both nationally and internationally; Duke/Flour Daniel, a joint venture with Fluor Daniel, Inc., which provides engineering, construction, and support of operating and maintenance activities, primarily for coal-fired generating plants, both nationally and internationally; Duke Merchandising, which sells and services quality electric merchandise and electronics; DukeNet Communications, Inc. (DukeNet), which was formed in 1994 to develop and manage communications systems (See "Subsequent Events"); and Duke Water Operations, which provides franchised water services for Anderson, South Carolina and Rutherfordton, North Carolina.

Employees

At December 31, 1994, the Company had 17,052 full-time employees, which included 1,011 full-time employees of subsidiaries and diversified activities. About 2,000 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW). During the last quarter of 1994, the Company reached new labor agreements with the IBEW for one year terms.

The Company has been engaged in a concentrated effort to more efficiently and effectively utilize its resources through better work practices. During 1994, the Company offered a voluntary separation program which gave most employees the option of leaving the Company for a lump-sum payment and severance pay based on years of service. This voluntary separation program resulted in the departure of approximately 1,300 employees in 1994. Implementing programs such as the voluntary separation program and other efficiency practices has resulted in continued work-force reduction and in streamlined work flows. The number of full-time employees has decreased to the present level from 19,945 at year-end 1990.

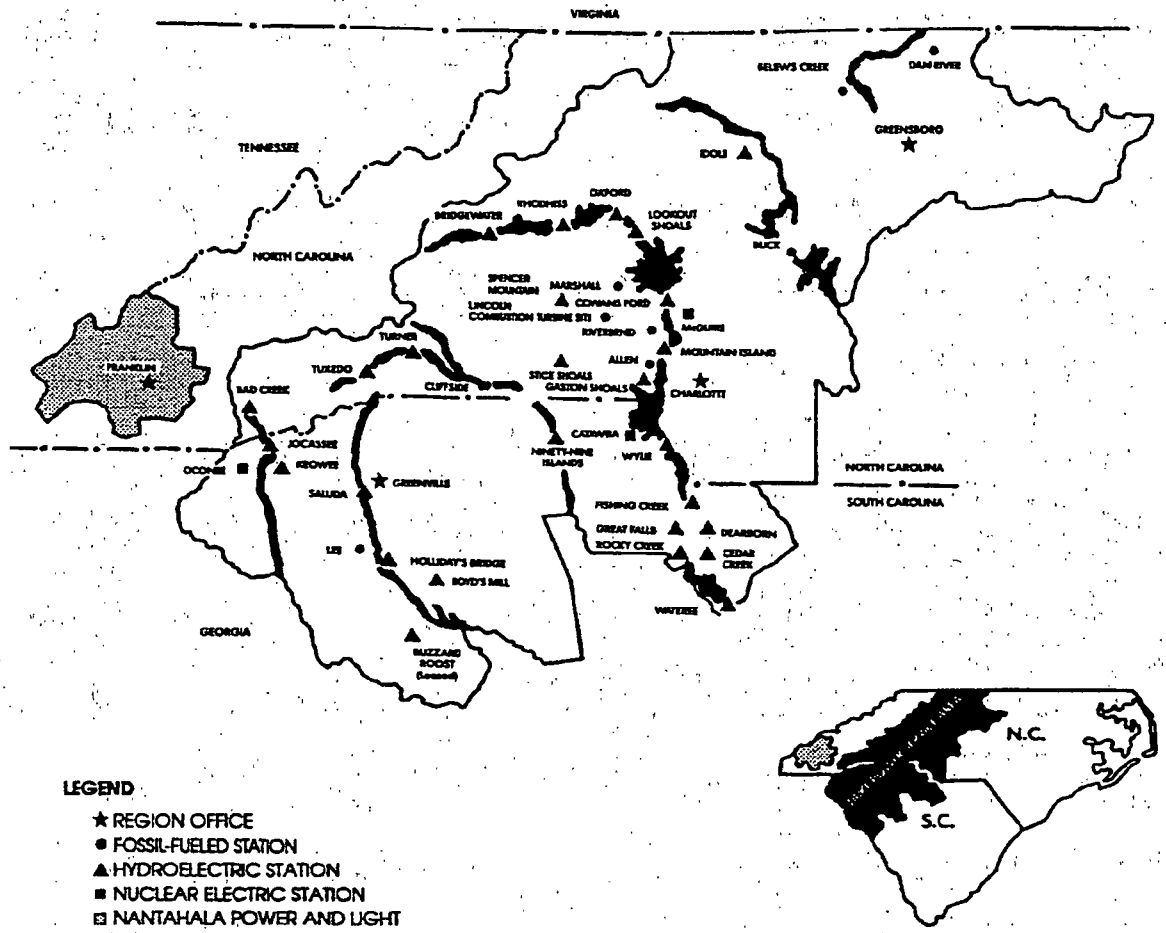
Subsequent Events

DukeNet entered into an agreement on December 8, 1994, as part of a consortium which includes BellSouth Personal Communications, Inc. and other companies, to bid for a personal communication services (PCS) license auctioned by the Federal Communications Commission (FCC). On March 13, 1995 the consortium won the bid and has agreed to pay for the license and, in compliance with FCC requirements, construct a substantial portion of the communication system. DukeNet has a 19.98% equity commitment to the consortium. Projected DukeNet capital commitments through 1999 are included in the Company's projected capital expenditures (See "Capital Requirements" on page 4).

On March 17, 1995, the Company filed for permission to sell wholesale electricity at market-driven prices with FERC. To date, the Company has sold wholesale power based on its bundled transmission, generation and distribution costs with an allowed return. The Company believes that this filing will strategically position the Company to become involved in the developing wholesale power market. The filing also included an open-access wholesale transmission tariff. This tariff sets the rates, terms and conditions under which the Company will transmit or wheel electricity from a third party through its system to a wholesale customer. Open access will provide the Company with increased opportunities to sell and deliver energy and capacity at market-based prices, thereby improving the utilization of existing assets. In addition, such access will provide an opportunity to buy energy and capacity at attractive rates, serving to further enhance the Company's competitive price position. In addition, Duke Energy Marketing Corp. (DEMC), an affiliate of Duke Energy, filed a request for power marketer status with FERC. Louis Dreyfus Electric Power and DEMC, in a joint venture, also filed an application with FERC for power marketer status. A power marketer buys blocks of electricity for immediate or eventual resale. Conditional approval is expected from FERC within six to eight months after filing. Final FERC approval for the filings is not expected for at least one year.

Recent liquidity problems in Argentina have caused a significant increase in Argentine interest rates and a severe limitation on local funds. Until such liquidity problems are resolved, Duke Energy is arranging financing alternatives which include additional equity infusions in its Argentine projects. Such infusions would not be material to the Company.

Duke Power Service Area



DUKE POWER COMPANY

OPERATING STATISTICS

	Year ended December 31				
	1994	1993	1992	1991	1990
Sources of Electric Energy (d)					
Millions of kilowatt-hours:					
Generated — net output:					
Coal	32,714	34,097	28,999	26,455	27,262
Nuclear (a)	50,887	48,211	48,238	49,328	44,649
Hydro (b)	1,460	1,582	1,834	1,545	1,879
Oil and gas	35	43	5	7	53
Total generation	85,096	83,933	79,076	77,335	73,843
Purchased power and net interchange (c)	1,276	1,750	1,403	587	1,531
Total output	86,372	85,683	80,479	77,922	75,374
Less: Other Catawba Joint Owners' share	15,300	13,821	14,313	12,280	11,735
Plus: Purchases from Other Catawba Joint Owners	9,046	8,810	9,466	8,525	8,658
Total sources of energy	80,118	80,672	75,632	74,167	72,297
Line loss and company usage	(4,555)	(4,614)	(4,590)	(4,280)	(4,222)
Total kilowatt-hour sales	75,563	76,058	71,042	69,887	68,075
Average Cost Per Ton of Coal Burned	$ 40.68	$ 42.21	$ 43.47	$ 45.21	$ 45.49
Electric Energy Sales (d)					
Millions of kilowatt-hours:					
Residential	18,870	19,465	17,789	17,918	17,221
General service	17,289	16,904	15,818	15,586	15,032
Industrial					
Textile	12,285	11,954	11,685	11,315	11,130
Other	17,005	16,244	15,356	14,955	14,764
Other energy and wholesale (c)(e)	10,274	11,337	10,360	10,132	10,468
Total kilowatt-hour sales billed	75,723	75,904	71,008	69,906	68,615
Unbilled kilowatt-hour sales	(160)	154	34	(19)	(540)
Total kilowatt-hour sales	75,563	76,058	71,042	69,887	68,075
Electric Revenue (d)					
Thousands of Dollars:					
Residential	1,379,740	1,424,173	1,312,227	1,272,322	1,216,945
General service	1,031,061	1,014,124	964,853	921,337	886,480
Industrial					
Textile	498,190	487,576	482,172	475,191	476,493
Other	745,154	726,399	696,413	668,765	654,551
Other energy and wholesale (c)(e)	540,256	476,862	460,849	441,777	391,803
Other electric revenue	84,928	152,742	44,970	37,568	78,859
Total electric revenues	$4,279,329	$4,281,876	$3,961,484	$3,816,960	$3,705,131
Number of Customers — End of Year (d)					
Residential	1,493,166	1,460,876	1,439,845	1,415,605	1,391,336
General service (f)	239,355	232,272	227,675	222,917	224,642
Industrial					
Textile	1,422	1,396	1,390	1,385	1,398
Other	7,320	7,338	7,314	7,255	7,325
Other energy and wholesale (c)	8,187	7,957	7,773	7,605	7,405
Total customers	1,749,450	1,709,839	1,683,997	1,654,767	1,632,106
Residential Customer Statistics (d)					
Average number for the year	1,483,497	1,455,609	1,431,403	1,409,775	1,383,799
Average annual use — KWH	12,720	13,372	12,427	12,710	12,444
Average annual billing	$ 930.06	$ 978.40	$ 916.74	$ 902.50	$ 879.42
Average Annual Billed Revenue Per KWH (d)					
Cents:					
Residential	7.31	7.32	7.38	7.10	7.07
General service	5.96	6.00	6.10	5.91	5.90
Industrial	4.24	4.31	4.36	4.35	4.37
Other energy and wholesale (c)(e)	5.26	4.21	4.45	4.36	3.74

(a) Includes 100% of Catawba generation.

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(b) 1991 includes KWH of the Bad Creek Hydroelectric Station prior to commercial operation.

(c) Kilowatt-hour sales, electric revenues, and Net interchange and purchased power for the year 1990 include a reclassification for certain power transactions previously classified as Net interchange and purchased power prior to a 1990 FERC order.

(d) Does not include operating statistics of NP&L.

(e) Includes sales to NP&L.

(f) 1991 restated to eliminate certain duplicate customers.

Executive Officers of the Company

WILLIAM H. GRIGG, 62, Chairman of the Board and Chief Executive Officer. Mr. Grigg served as Chairman of the Board, President and Chief Executive Officer, effective April 28, 1994, until July 27, 1994 when he assumed his present position. He served as Vice Chairman of the Board beginning in 1991, and Executive Vice President, Customer Group, beginning in 1988.

STEVE C. GRIFFITH, JR., 61, Vice Chairman of the Board and General Counsel. Mr. Griffith served as Executive Vice President and General Counsel from 1991 until he assumed his present position in July 1994. He served as Senior Vice President and General Counsel from 1982 until 1991.

RICHARD B. PRIORY, 48, President and Chief Operating Officer. Mr. Priory served as Executive Vice President, Power Generation Group, from 1991 until he assumed his present position in July 1994. He was Senior Vice President, Generation and Information Services, from 1988 to 1991.

WILLIAM A. COLEY, 51, President, Associated Enterprises Group. Mr. Coley was named Senior Vice President, Power Delivery, in 1988; Senior Vice President, Customer Group, in 1990; and Executive Vice President, Customer Group, in 1991. He was named to his present position in July 1994.

RICHARD J. OSBORNE, 43, Senior Vice President and Chief Financial Officer. Prior to assuming his current position in July 1994, Mr. Osborne served as Vice President and Chief Financial Officer beginning in 1991 and Vice President, Finance, from 1988 to 1991.

JEFFREY L. BOYER, 38, Controller. Mr. Boyer served as Director of Corporate Accounting for more than five years prior to assuming his present position in July 1994.

Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Item 2. *Properties.*

At December 31, 1994, the Company operated three nuclear generating stations, eight coal-fired stations and twenty-seven hydroelectric stations, all of which are located in North Carolina or South Carolina.

The following is a list of the major generating stations owned by the Company at December 31, 1994:

Facility	Energy Source	Net MW
Oconee	Nuclear	2,538
McGuire	Nuclear	2,258
Catawba (a)	Nuclear	2,258
Belews Creek	Coal	2,240
Marshall	Coal	2,090
Allen	Coal	1,140
Cliffside	Coal	760
Others	Coal	1,431
Bad Creek	Hydroelectric	1,065
Jocassee	Hydroelectric	610
Others	Hydroelectric	1,007
Combustion turbines	Oil and gas	584

(a) The Catawba Nuclear Station is a jointly-owned facility, of which the Company's ownership share is 12½ percent.

The Company is currently constructing the Lincoln Combustion Turbine Station, a 16-turbine facility designed to provide capacity at periods of peak demand. The station will have a total generating capacity of 1,184 megawatts. The facility is designed to operate on either natural gas or oil.

In addition to the electric generating plants described above, the Company owned, as of December 31, 1994, approximately 8,300 conductor miles of transmission lines and approximately 72,500 conductor miles of distribution lines. As of such date, the Company's transmission and distribution systems comprised approximately 1,700 substations with an installed transformer capacity of approximately 83,100,000 kVA.

NP&L's generation facilities consist of eleven hydroelectric plants with an aggregate nameplate capacity of approximately 100 MW. The transmission backbone of the system is a 161 kV line from Santeetlah to substations at Robbinsville, Nantahala Plant, Oak Grove, Webster and Thorpe Plant.

The map on page 11 shows the location of the Company's and NP&L's service area and generating stations.

Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see "Business — Energy Requirements and Capability" and "Capital Requirements".

Item 3. *Legal Proceedings.*

Reference is made to "Business — Regulation", "Management Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — Commitment and Contingencies" and "Note 13, Notes to Consolidated Financial Statements, Commitments and Contingencies — Other".

Item 4. *Submission of Matters to a Vote of Security Holders.*

No matters were submitted to a vote of the Company's security holders during the last quarter of 1994.

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PART II.

Item 5. ***Market for the Registrant's Common Equity and Related Stockholder Matters.***

The Common Stock of the Company is traded on the New York Stock Exchange. At December 31, 1994, there were approximately 129,637 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by the New York Stock Exchange Composite Transactions:

Common Stock	Dividends Per Share	Stock Price Range	
		High	Low
1994 By Quarter			
Fourth	$0.49	$42 1/8	$38
Third	0.49	39 7/8	35 1/2
Second	0.47	37	32 7/8
First	0.47	43	35 3/4
1993 By Quarter			
Fourth	$0.47	$44	$39
Third	0.47	44 7/8	39 7/8
Second	0.45	41 3/8	37 1/8
First	0.45	39 7/8	35 3/8

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Item 6.

SELECTED FINANCIAL DATA

	1994	1993	1992	1991	1990
Condensed consolidated statements of income (thousands)					
Operating revenues (a)	$ 4,488,913	$ 4,466,233	$ 4,122,503	$ 3,962,605	$ 3,862,395
Operating expenses (a)	3,309,087	3,258,422	3,087,422	2,968,239	2,949,387
Operating income	1,179,826	1,207,811	1,035,081	994,366	913,008
Interest expense and other income	(143,931)	(171,419)	(223,028)	(117,725)	(124,826)
Income before income taxes	1,035,895	1,036,392	812,053	876,641	788,182
Income taxes	397,019	409,977	303,970	293,018	249,994
Net income	638,876	626,415	508,083	583,623	538,188
Dividends on preferred and preference stock	49,724	52,429	56,407	54,683	52,616
Earnings for common stock	$ 589,152	$ 573,986	$ 451,676	$ 528,940	$ 485,572
Common stock data (b)					
Shares of common stock					
year-end (thousands)	204,859	204,859	204,859	204,699	202,584
average (thousands)	204,859	204,859	204,819	203,431	202,570
Per share of common stock					
Earnings	$ 2.88	$ 2.80	$ 2.21	$ 2.60	$ 2.40
Dividends	$ 1.92	$ 1.84	$ 1.76	$ 1.68	$ 1.60
Book value — year-end	$ 22.13	$ 21.17	$ 20.26	$ 19.86	$ 18.84
Market price — high-low	$ 43-32⅞	$ 44⅞-35⅜	$ 37½-31⅜	$ 35-26¾	$ 32⅜-25½
— year-end	$ 38⅛	$ 42⅜	$ 36⅛	$ 35	$ 30⅜
Balance sheet data (thousands)					
Total assets	$12,862,228	$12,293,605	$11,012,795	$10,617,552	$10,083,507
Long-term debt	$ 3,567,122	$ 3,285,397	$ 3,288,111	$ 3,235,492	$ 3,102,746
Preferred stock with sinking fund requirements	$ 279,500	$ 281,000	$ 279,519	$ 228,650	$ 239,800

(a) Operating revenues and operating expenses for the year 1990 include a reclassification for certain power transactions previously classified as Net interchange and purchased power prior to 1990 FERC order.

(b) All common stock data reflects the two-for-one split of common stock on September 28, 1990.

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Item 7. *Management's Discussion and Analysis of Results of Operations and Financial Condition*

Results of Operations

Earnings and Dividends. Earnings per share increased 3 percent from $2.80 in 1993 to $2.88 in 1994. The increase was primarily due to increased earnings of subsidiaries and diversified activities, increased allowance for funds used during construction and other deferred returns, and pre-funding of charitable contributions to the Duke Power Foundation in 1993. These items were offset by higher operating and maintenance expenses including recognition of certain non-recurring costs.

Excluding $.32 for the effect of a one-time refund to North Carolina retail customers in 1992, earnings per share increased from $2.53 in 1992 to $2.88 in 1994, indicating an average annual growth rate of 7 percent. Total Company earned return on average common equity was 13.3 percent in 1994 compared with 13.6 percent in 1993 and 12.8 percent in 1992, excluding the effects of the 1992 refund.

The Company continued its practice of annually increasing the common stock dividend. Common dividends per share increased at an average annual rate of 4 percent from $1.76 in 1992 to $1.92 in 1994. Indicated annual dividends per share increased to $1.96.

Revenues and Sales. Operating revenues increased at an average annual rate of 4 percent from 1992 to 1994, primarily because of increased overall kilowatt-hour sales to all retail customer classes. Revenues from subsidiaries and diversified activities contributed $49 million to the increase in Operating revenues over the three-year period, primarily from increased developed lot sales, land sales and equity earnings from investments in domestic and international joint ventures.

The Company does not expect the trend of annually increasing electric revenues to continue for 1995 and 1996 if normal weather conditions occur. Total electric revenues in 1995 and 1996 are expected to remain approximately the same as 1994 and increase thereafter. Revenues from retail customers are expected to increase because of continued growth in the service area. However, wholesale revenues are expected to decline as the other joint owners of the Catawba Nuclear Station retain a significantly larger portion of their ownership entitlement in 1995 and 1996, thereby reducing supplemental requirements supplied by the Company. The effect on earnings of such wholesale revenue decline will be partially offset by a decline in purchased power costs from the other joint owners which are not subject to levelization. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

Kilowatt-hour sales from Duke Power electric operations decreased 1 percent in 1994 compared with 1993. Sales to general service, textile and other-industrial customers increased by 2 percent, 3 percent and 5 percent, respectively, as a result of continued economic growth in Duke Power's service area. A new record peak demand of 16,070 megawatts was set in January 1994 for Duke Power's electric operations during a period of extremely cold temperatures. However, weather for most of the year was milder than normal and milder than 1993.

As a result, sales to residential customers decreased by 3 percent. Kilowatt-hour sales to the other joint owners of the Catawba Nuclear Station decreased 18 percent primarily because of improved output of the Catawba and McGuire Nuclear Stations from which they receive their energy entitlements.

Operating Expenses. From 1993 to 1994, Other operation and maintenance expenses rose 7 percent. Nuclear plant maintenance expenses increased primarily as a result of increased refueling outages, while fossil plant maintenance expenses increased primarily as a result of turbine and boiler outages. Administrative and general expenses increased primarily because of costs associated with a voluntary separation program offered during 1994 and non-recurring claims. (For additional information on the voluntary separation program, see Current Issues "Resource Optimization," page 20.)

Other operation and maintenance expenses increased at an average annual rate of 7 percent from 1992 to 1994. Administrative and general expenses increased over the period principally because of the voluntary separation program offered in 1994 and non-recurring claims. Fossil operating and maintenance expenses increased as a result of bringing refurbished units back on-line and increased boiler and turbine outages.

Fuel expense increased at an average annual rate of 3 percent from 1992 to 1994. The increase was due primarily to higher system production requirements satisfied by increased fossil generation. A continued decline of fuel prices over this period partially offset the overall increase in fuel expenses.

Net interchange and purchased power increased from $539 million in 1992 to $553 million in 1994, an average annual increase of 1 percent.

From 1992 to 1994, Depreciation and amortization expense decreased at an average annual rate of 4 percent primarily because the reduction in the amortization of property losses more than offset depreciation associated with additional investments. These investments are primarily associated with distribution plant including investment to support customer growth, and fossil plant resulting from bringing refurbished units back on-line.

Interest Expense and Other Income. Interest expense decreased at an average annual rate of 7 percent from 1992 to 1994. Interest on long-term debt decreased because of the Company's refinancing of higher-cost debt beginning in late 1991 and continuing throughout 1993. Interest expense also decreased as a result of the one-time impact in 1992 of approximately $27 million in interest paid to North Carolina retail customers because of a rate refund.

Allowance for funds used during construction (AFUDC) and other deferred returns, net of associated taxes, represented 13 percent of earnings for common stock in 1994 compared with 11 percent in 1992. AFUDC and other deferred returns are expected to be less than 14 percent of total earnings during the next three years.

AFUDC, net of associated taxes, represented 6 percent of earnings for common stock in 1994 compared with 5 percent in 1992. The increase was primarily the result of increased investment in the Lincoln Combustion Turbine Station. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs "Meeting Future Power Needs," page 20.)

The accrued return, net of associated taxes, on the purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station represented 7 percent of earnings for common stock in 1994 compared with 6 percent in 1993 and 1992. The growth in this return is due to the increasing cumulative impact of the Company's funding of purchased power costs, which the Company expects to collect through current rates in future periods. (For additional information on purchased capacity levelization, see Capital Needs "Purchased Capacity Levelization," page 19.)

Liquidity and Resources

Significant Rate Matters. During 1991, Duke Power filed in both the North Carolina and South Carolina retail jurisdictions its only requests for general rate increases since 1986. General rate increases approved in November 1991 resulted in additional annual revenues of $100.1 million and $30.2 million in North Carolina and South Carolina, respectively. The increases were needed primarily to recover costs associated with the commercial operation of the Bad Creek Hydroelectric Station.

In 1992, the North Carolina Supreme Court remanded to the North Carolina Utilities Commission (NCUC) Duke Power's 1986 rate order for the second time. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order in 1992 which resulted in a 1992 refund to North Carolina retail customers of approximately $95 million, including interest.

Duke Power has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all of Duke Power's regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

Catawba Settlements. The other joint owners of the Catawba Nuclear Station and the Company were involved in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which previously have been approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.) The Company and the other joint owners entered into settlement agreements in 1994 which resolved all issues in contention in the proceedings. The Company has settled its cumulative net obligation through 1993 of approximately $205 million with the other joint owners. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because it expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, the Company has included approximately $205 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Cash from Operations. Consolidated net cash provided by operating activities in 1994 accounted for 67 percent of total cash from operating, financing and investing activities compared with 46 percent in 1993 and 51 percent in 1992. Substantially all of the Company's capital needs were met by cash generated from operating activities for 1993 and 1992 when refinancing activities are excluded. Refinancing activities were insignificant in 1994.

Financing and Investing Activities. The Company's consolidated capital structure at year-end 1994, including subsidiary long-term debt, was 51 percent common equity, 40 percent long-term debt and 9 percent preferred stock. This structure is consistent with the Company's target to maintain a double-A credit rating. As of December 31, 1994, Duke Power's bonds were rated "AA" by Fitch Investors Service, "Aa2" by Moody's Investors Service, and "AA-" by Standard & Poor's Group and Duff & Phelps.

In response to favorable market conditions in 1992 and 1993, the Company refinanced $2.3 billion of long-term debt and $445 million of preferred stock. While there were no significant refinancings in 1994, the Company issued $407 million in debt, primarily First and Refunding Mortgage Bonds.

Duke Power's embedded cost of long-term debt, excluding debt of subsidiaries, was 7.98 percent for 1994 compared with 8.01 percent in 1993 and 8.39 percent in 1992. The embedded cost of preferred stock was 6.99 percent in 1994 compared with 6.76 percent in 1993 and 7.05 percent in 1992. The decreases are primarily the result of the Company's refinancing activities. The increase in the embedded cost of preferred stock from 1993 to 1994 reflects the impact of increasing dividend rates on variable rate preferred stocks.

Fixed Charges Coverage. Consolidated fixed charges coverage using the SEC method increased to 4.72 times for 1994 compared with 4.68 and 3.49 times in 1993 and 1992, respectively. Coverage increased primarily because of lower interest as a result of refinancing activities. Consolidated fixed charges coverage, excluding AFUDC and other deferred returns, was 4.32 for 1994 compared with 4.39 in 1993 and 3.27 in 1992 and the Company goal of 3.5 times. Coverage was somewhat lower in 1994 than 1993 as a result of a decrease in earnings excluding AFUDC and other deferred returns and higher in 1994 than 1992 because of higher earnings and lower interest expense.

Capital Needs

Property Additions and Retirements. Additions to property and nuclear fuel of $883 million and retirements of $238 million resulted in an increase in gross plant of $645 million in 1994.

Since January 1, 1992, additions to property and nuclear fuel of $2.2 billion and retirements of $839 million have resulted in an increase in gross plant of $1.4 billion.

Construction Expenditures. Plant construction costs for generating facilities supporting Duke Power electric operations, including AFUDC, increased from $145 million in 1992 to $309 million in 1994, primarily because of construction of the Lincoln Combustion Turbine Station. (For more information, see Capital Needs "Meeting Future Power Needs," page 20.) Construction costs for distribution plant, including AFUDC, decreased from $224 million in 1992 to $203 million in 1994.

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including AFUDC, are $3.0 billion and $620 million, respectively, for 1995 through 1999. Total projected construction costs include expenditures for the construction of the Lincoln Combustion Turbine Station and the replacement of certain steam generators at the McGuire and Catawba Nuclear Stations. (For additional information on steam generator replacement, see Current Issues "Stress Corrosion Cracking," page 21.) Projected capital expenditures of subsidiaries and diversified activities are $661 million for 1995 through 1999. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital. For 1995 through 1999, the Company anticipates funding its projected construction expenditures through the internal generation of funds and, to a lesser extent, through the issuance of debt securities.

Purchased Capacity Levelization. The rates established in Duke Power's electric retail jurisdictions permit recovery of its investment in both units of the Catawba Nuclear Station and the costs associated with contractual purchases of capacity from the other Catawba joint owners. The contracts relating to the sales of portions of the station obligate the Company to purchase a declining amount of capacity from the other joint owners. In the North Carolina retail jurisdiction, regulatory treatment of these contracts provides revenue for recovery of the capital costs and the fixed operating and maintenance costs of purchased capacity on a levelized basis. In the South Carolina retail jurisdiction, revenues are provided for the recovery of

the capital costs of purchased capacity on a levelized basis, while current rates include recovery of fixed operating and maintenance expenses.

Such rate treatments require the Company to fund portions of the purchased capacity payments until these costs, including accrued returns, are recovered at a later date. The Company recovers the accumulated costs and returns when the sum of the declining purchased capacity payments and accrual of returns for the current period drop below the levelized revenues. In the North Carolina retail jurisdiction, and wholesale jurisdiction regulated by the Federal Energy Regulatory Commission (FERC), purchased capacity payments continue to exceed levelized revenues. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups.

Meeting Future Power Needs. The Company's strategy for meeting customers' present and future energy needs consists of three components: supply-side resources, demand-side resources and purchased power resources. To assist in determining the optimal combination of these three resources, the Company uses an integrated resource planning process. The goal is to provide adequate and reliable electricity in an environmentally responsible, cost-effective manner.

The Company is building a combustion turbine facility in Lincoln County, North Carolina. The Lincoln Combustion Turbine Station, designed to provide capacity at periods of peak demand, will consist of 16 combustion turbines with a total generating capacity of 1,184 megawatts. The estimated total cost of the project is approximately $500 million. Current plans are for 12 units to begin commercial operation by the end of 1995 and the remaining four to begin commercial operation in 1996.

Demand-side management programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the Public Service Commission of South Carolina (PSCSC) provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The Company ultimately expects recovery through rates of associated deferred costs. The annual costs deferred, including the return, were approximately $25 million in 1994 and $26 million in 1993.

As of January 1, 1995, the Company has under contract 300 megawatts of firm purchased capacity from other generators of electricity, including 62 megawatts from qualifying facilities. The purchase of capacity and energy is also an integral part of meeting future power needs. The Company expects to use a competitive bidding process to provide for the next increment of generating capacity beyond the Lincoln Combustion Turbine Station.

Current Issues

While the Company improved its financial performance in 1994 compared with 1993, the ability to maintain and improve its current level of earnings will depend on several factors. As the industry becomes increasingly competitive, the Company's ability to control costs will be an important factor in maintaining a pricing structure that is both attractive to customers and profitable to the Company. While retail wheeling is presently not allowed in any form in the Company's service territory, the Company is focusing on providing competitive cost-based prices to its industrial customers, as well as to wholesale customers who already have access to alternative sources of energy. Other significant factors impacting the Company's future earnings levels include continued economic growth in the Piedmont Carolinas, the success of the Company's subsidiaries and diversified activities, and the outcome of various legislative and regulatory actions.

Resource Optimization. The Company has been engaged in a concentrated effort to more efficiently and effectively use its resources through better work practices. During 1994, the Company offered a voluntary separation program which gave most employees the option of leaving the Company for a lump-sum payment and severance pay based on years of service. This voluntary separation program resulted in the departure of approximately 1,300 employees in 1994. Implementing programs such as the voluntary separation program and other efficiency practices has resulted in continued work-force reduction and in streamlined work flows. The number of full-time employees has decreased from 19,945 at year-end 1990 to 17,052 at year-end 1994.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the

Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Such estimates presume each unit will be decommissioned as soon as possible following the end of its license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021, McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The Nuclear Regulatory Commission (NRC) issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1994, the Company expensed approximately $52.5 million which was contributed to the external funds and accrued an additional $4.8 million to the internal reserve. The balance of the external funds as of December 31, 1994, was $172.4 million. The balance of the internal reserve as of December 31, 1994, was $204.8 million and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets.

Both the NCUC and the PSCSC have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

Environmental Issues. The Company is subject to federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal, and other environmental matters. The Company was an operator of manufactured gas plants until the early 1950s. The Company has entered into a cooperative effort with the state of North Carolina and other owners of certain former manufactured gas plant sites to investigate and, where necessary, remediate these contaminated sites. The state of South Carolina has expressed interest in entering into a similar arrangement. The Company is considered by regulators to be a potentially responsible party and may be subject to liability at three federal Superfund sites and three comparable state sites. While the cost of remediation of these sites may be substantial, the Company will share in any liability associated with remediation of contamination at such sites with other potentially responsible parties. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

The Clean Air Act Amendments of 1990. The Clean Air Act Amendments of 1990 require a two-phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national objective of clean air in the most cost-effective manner and has already reduced emissions through the use of low-sulfur coal in its fossil plants, efficient plant operations and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. The Company is currently developing a detailed compliance plan for Phase II requirements which must be filed with the Environmental Protection Agency (EPA) by 1996. A preliminary strategy, which allows for varying options, indicates one-time costs associated with bringing the Company into compliance with the Act could range from $260 million to $750 million, depending on the compliance options the Company selects. The final strategy is contingent upon developments in the emissions allowance market, future regulatory and legislative actions, and advances in clean air technology. Additional annual operating and maintenance expenses will be incurred as well. All options within the preliminary strategy provide for full compliance with Phase II requirements by the year 2000.

Stress Corrosion Cracking. Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company is planning for the replacement of steam generators at three units that have experienced SCC and has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. The current schedule for completion of the effort is as follows: Catawba Unit 1 — 1996, McGuire Unit 1 — 1997 and McGuire Unit 2 — 1997. The order of replacement is subject to change based on operational and project circumstances. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $170 million, excluding the cost of replacement power and the reimbursement of applicable costs by the other joint owners for Catawba Unit 1. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the other joint owners of the Catawba Nuclear Station, began a legal action on March 22, 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba stations steam generators that were defective in design, workmanship and materials, requiring replacement well short of their stated design life. On March 17, 1994, the Company, together with the other joint owners of the Catawba Station, settled the lawsuit. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the results of operation or financial position of the Company.

Competition. The Energy Policy Act of 1992 (EPACT) is moving utilities toward a more competitive environment. The EPACT reformed certain provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain regulatory barriers. For example, the EPACT allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. The EPACT requires transmission of power for third parties to wholesale customers on issuance of an order by the FERC, provided the reliability of service to the utility's local customer base is protected and the local customer base does not subsidize the third-party service. The EPACT does not permit the FERC to issue an order requiring transmission access to retail customers.

The electric utility industry currently is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry, for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced and utilities might be required to reduce their recorded asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation could also require some utilities to write off their regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are regionally and nationally competitive. The Company anticipates filing an open access transmission tariff with the FERC in early 1995. Open access would provide the Company with increased opportunities to sell and deliver energy and capacity at market-based prices, thereby improving the utilization of existing assets. In addition, such access would provide an opportunity to buy energy and capacity at attractive rates, serving to further enhance the Company's competitive price position.

Commitments and Contingencies. The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which may involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

Subsidiaries and Diversified Activities. The Company continues to aggressively pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Although these opportunities are concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks.

The Company's subsidiaries and diversified activities contributed $52 million to net income in 1994 compared with $22 million in 1993 and $25 million in 1992. Increased developed lot and land sales, the sale of commercial rental property and the operation of generation and transmission facilities outside Duke Power's regulated service area generated additional income in 1994. A one-time gain on the sale of an investment in the preferred stock of an independent power development company also contributed to diversified income. Earnings of subsidiaries and diversified activities also include income from passive financial investments, engineering services fees, water operations and merchandising.

Domestically, the Company is seeking opportunities to: provide communications, water and engineering consulting services; construct, operate and maintain generation and transmission facilities; own generation facilities outside Duke Power's regulated service area; develop real estate; sell and service appliances and electronics; and participate in power marketing activities. The Company had equity investments in joint ventures, which own assets within the United States, of $14 million and $17 million at December 31, 1994 and 1993, respectively. Non-electric property of the Company's subsidiaries and diversified activities was $286 million and $216 million at December 31, 1994 and 1993, respectively.

Internationally, the Company is seeking opportunities to construct, own, operate and maintain generation and transmission facilities and to provide engineering consulting services. The Company had equity investments in international joint ventures, which own generation and transmission facilities, of $94 million and $85 million at December 31, 1994 and 1993, respectively.

ITEM 8. *Financial Statements and Supplementary Data.*

DUKE POWER COMPANY

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DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Operating revenues (Notes 1, 2 and 11)	$4,488,913	$4,466,233	$4,122,503
Operating expenses			
Fuel used in electric generation (Note 1)	705,019	732,246	659,593
Net interchange and purchased power (Notes 2 and 3)	553,355	535,125	538,841
Other operation and maintenance	1,341,659	1,254,028	1,166,940
Depreciation and amortization (Note 1)	459,781	496,971	499,048
General taxes	249,273	240,052	223,000
Total operating expenses	3,309,087	3,258,422	3,087,422
Operating income	1,179,826	1,207,811	1,035,081
Interest expense and other income (Note 1)			
Interest expense	(270,217)	(274,051)	(312,885)
Allowance for funds used during construction and other deferred returns	111,872	82,600	70,172
Other, net	14,414	20,032	19,685
Total interest expense and other income	(143,931)	(171,419)	(223,028)
Income before income taxes	1,035,895	1,036,392	812,053
Income taxes (Notes 1 and 4)	397,019	409,977	303,970
Net income	638,876	626,415	508,083
Dividends on preferred and preference stock	49,724	52,429	56,407
Earnings for common stock	$ 589,152	$ 573,986	$ 451,676
Common stock data (Note 6)			
Average shares outstanding (thousands)	204,859	204,859	204,819
Earnings per share	$ 2.88	$ 2.80	$ 2.21
Dividends per share	$ 1.92	$ 1.84	$ 1.76

See Notes to Consolidated Financial Statements.

DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Balance — Beginning of year	$2,410,825	$2,223,718	$2,141,259
Add — Net income	638,876	626,415	508,083
Total	3,049,701	2,850,133	2,649,342
Deduct			
Dividends			
Common stock	393,370	376,937	360,475
Preferred and preference stock	49,724	52,429	56,407
Capital stock transactions, net	687	9,942	8,742
Total deductions	443,781	439,308	425,624
Balance — End of year	$2,605,920	$2,410,825	$2,223,718

See Notes to Consolidated Financial Statements.

DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Cash flows from operating activities			
Net Income	$ 638,876	$ 626,415	$ 508,083
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash items			
Depreciation and amortization (Note 1)	647,515	664,355	668,497
Deferred income taxes and investment tax credit amortization (Note 4)	94,261	62,897	49,490
Allowance for equity funds used during construction	(27,411)	(17,221)	(15,476)
Purchased capacity levelization (Note 3)	(268,925)	(20,049)	(66,511)
Other, net	22,460	73,607	37,978
(Increase) Decrease in Accounts receivable	47,586	(37,131)	8,166
Inventory	(28,568)	24,904	(11,131)
Prepayments	(435)	(2,396)	(1,084)
Increase (Decrease) in Accounts payable	(52,506)	(28,184)	75,976
Taxes accrued (Notes 1 and 4)	(51,641)	25,797	1,758
Interest accrued and other liabilities (Notes 1, 9 and 13)	14,523	30,508	(22,731)
Total adjustments	396,859	777,087	724,932
Net cash provided by operating activities	1,035,735	1,403,502	1,233,015
Cash flows from investing activities			
Construction expenditures and other property additions	(772,452)	(599,759)	(504,667)
Investment in nuclear fuel	(108,711)	(111,731)	(122,565)
External funding for decommissioning (Note 14)	(52,524)	(52,524)	(61,246)
Pre-funded pension cost (Note 12)	(30,000)	(50,000)	—
Investment in joint ventures (Note 11)	(6,718)	(70,345)	(18,565)
Net change in investment securities (Note 1)	17,922	46,489	(81,588)
Net cash used in investing activities	(952,483)	(837,870)	(788,631)
Cash flows from financing activities			
Proceeds from the issuance of			
First and refunding mortgage bonds	343,824	1,395,682	926,650
Preferred stock	—	215,633	281,089
Pollution-control bonds	—	76,265	—
Short-term notes payable, net (Note 5)	86,300	(105,200)	28,300
Construction loans and other	57,032	13,280	23,435
Payments for the redemption of			
First and refunding mortgage bonds	(81,781)	(1,399,336)	(1,013,218)
Preferred stock	(1,500)	(224,295)	(246,414)
Pollution-control bonds	—	(79,310)	—
Construction loans and other	(18,885)	(12,454)	(13,939)
Dividends paid	(443,633)	(427,868)	(417,443)
Other	(20,991)	(6,752)	(6,183)
Net cash used in financing activities	(79,634)	(554,355)	(437,723)
Net increase in cash	3,618	11,277	6,661
Cash at beginning of year	33,812	22,535	15,874
Cash at end of year	$ 37,430	$ 33,812	$ 22,535

See Notes to Consolidated Financial Statements.

DE00000499

DUKE POWER COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 1994	December 31, 1993
	Dollars in Thousands	
ASSETS		
Current assets		
Cash (Notes 5 and 10)	$ 37,430	$ 33,812
Short-term investments (Note 10)	132,692	120,632
Receivables (less allowance for losses: 1994 — $6,637; 1993 — $6,404) (Note 1)	552,865	553,509
Inventory — at average cost	319,385	282,909
Prepayments and other	15,722	15,286
Total current assets	1,058,094	1,006,148
Investments and other		
Investments in joint ventures (Note 11)	108,330	101,612
Other investments, at cost or less (Note 10)	83,226	113,208
Nuclear decommissioning trust funds (Notes 10 and 14)	172,390	118,456
Pre-funded pension cost (Note 12)	80,000	50,000
Total investments and other assets	443,946	383,276
Property, plant and equipment		
Electric plant in service (at original cost — Notes 1, 3, 9, 13 and 14)		
Production	6,747,397	6,549,807
Transmission	1,439,435	1,400,790
Distribution	3,965,393	3,786,389
Other	1,020,192	974,123
Electric plant in service	13,172,417	12,711,109
Less accumulated depreciation and amortization	4,810,004	4,501,481
Electric plant in service, net	8,362,413	8,209,628
Nuclear fuel	757,983	705,994
Less accumulated amortization	415,560	405,910
Nuclear fuel, net	342,423	300,084
Construction work in progress (including nuclear fuel in process: 1994 — $52,273; 1993 — $113,904)	558,730	496,833
Total electric plant, net	9,263,566	9,006,545
Other property — at cost (less accumulated depreciation: 1994 — $24,137; 1993 — $20,314	302,383	236,634
Total property, plant and equipment, net	9,565,949	9,243,179
Deferred debits (Notes 1, 3, 4 and 13)		
Purchased capacity costs	932,324	768,099
Debt expense	186,306	197,963
Regulatory asset related to income taxes	489,292	486,440
Regulatory asset related to DOE assessment fee	102,467	116,731
Other	83,850	91,769
Total deferred debits	1,794,239	1,661,002
Total assets	$12,862,228	$12,293,605
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 343,688	$ 373,202
Notes payable (Notes 5 and 10)	107,100	20,800
Taxes accrued (Note 1)	29,999	82,500
Interest accrued	72,157	68,868
Current maturities of long-term debt and preferred stock (Notes 8 and 9)	93,759	91,898
Other (Note 13)	121,539	215,543
Total current liabilities	768,242	852,811
Long-term debt (Notes 9 and 10)	3,567,122	3,285,397
Accumulated deferred income taxes (Notes 1 and 4)	2,348,631	2,243,366
Deferred credits and other liabilities		
Investment tax credit (Notes 1 and 4)	272,594	283,964
DOE assessment fee (Note 1)	102,467	116,731
Nuclear decommissioning costs externally funded (Note 14)	172,390	118,456
Other	318,453	274,146
Total deferred credits and other liabilities	865,904	793,297
Preferred and preference stock with sinking fund requirements (Notes 8 and 10)	279,500	281,000
Preferred and preference stock without sinking fund requirements (Notes 7 and 10)	500,000	500,000
Commitments and contingencies (Note 13)		
Common stockholders' equity (Notes 6 and 7)		
Common stock, no par, 300,000,000 shares authorized; 204,859,539 shares outstanding for 1994 and 1993	1,926,909	1,926,909
Retained earnings	2,605,920	2,410,825
Total common stockholders' equity	4,532,829	4,337,734
Total liabilities and stockholders' equity	$12,862,228	$12,293,605

See Notes to Consolidated Financial Statements.

DE00000500

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Revenues

Electric revenues are recorded as service is rendered to customers. "Receivables" on the Consolidated Balance Sheets include $163,270,000 and $175,726,000 as of December 31, 1994 and 1993, respectively, for electric service that has been rendered but not yet billed to customers.

B. Additions to Electric Plant

The Company capitalizes all construction-related direct labor and materials as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of money (allowance for funds used during construction). The cost of renewals and betterments of units of property is capitalized.

The cost of repairs and replacements representing less than a unit of property is charged to electric expenses. The original cost of property retired, together with removal costs less salvage value, is charged to accumulated depreciation.

C. Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities. AFUDC, a non-cash item, is recognized as a cost of "Construction work in progress" (CWIP), with an offsetting credit to "Interest expense and other income." After construction is completed, the Company is permitted to recover these construction costs, including a fair return, through their inclusion in rate base and in the provision for depreciation.

The 1994 and 1993 AFUDC rates of 9.64 and 9.29 percent for Duke Power include a component for debt cost on a pre-tax basis. The 1992 rate of 8.07 percent includes a component for debt cost on a net of tax basis. The change in calculation from a net of income tax basis to a pre-tax basis is a result of the adoption of Statement of Financial Accounting Standards No. 109 (SFAS 109). (See Note 4.) Rates for all periods are compounded semiannually.

D. Other Deferred Returns

Other deferred returns represent the estimated financing costs associated with funding certain regulatory assets. These regulatory assets primarily arise from the Company's funding of purchased capacity cost above levels collected in rates. Other deferred returns are non-cash items. They are primarily recognized as an addition to "Purchased capacity costs" and as an offsetting credit to "Interest expense and other income."

E. Depreciation and Amortization of Electric Plant

Provisions for electric plant depreciation are recorded using the straight-line method. The year-end composite weighted-average depreciation rates were 3.46 percent for 1994, 3.47 percent for 1993 and 3.48 percent for 1992.

Amortization of nuclear fuel is included in "Fuel used in electric generation" in the Consolidated Statements of Income. The amortization is recorded using the units-of-production method.

Under provisions of the Nuclear Waste Policy Act of 1982, the Company has entered into contracts with the Department of Energy (DOE) for the disposal of spent nuclear fuel. Payments made to the DOE for disposal costs are based on nuclear output and are included in "Fuel used in electric generation" in the Consolidated Statements of Income.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid $18,008,000 during 1994 and has paid $26,346,000 cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of $102,467,000 in the Consolidated Balance Sheets at December 31, 1994.

F. Subsidiaries

The Company's consolidated financial statements reflect consolidation of all of its majority-owned subsidiaries. Intercompany transactions have been eliminated in consolidation.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

G. Income Taxes

The Company and its subsidiaries file a consolidated federal income tax return.

Deferred income taxes have been provided for temporary differences. Temporary differences occur when events and transactions recognized for financial reporting result in taxable or tax-deductible amounts in future periods. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

H. Unamortized Debt Premium, Discount and Expense

Expenses incurred in connection with the issuance of presently outstanding long-term debt issued for regulated operations, and premiums and discounts relating to such debt, are being amortized over the terms of the respective issues. Also, any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations used to finance regulated assets and operations are being amortized over the lives of the new issues of long-term debt.

I. Consolidated Statements of Cash Flows

For purposes of the Consolidated Statements of Cash Flows, the Company's short-term investments in highly liquid debt instruments, with an original maturity of three months or less, are included in cash flows from investing activities and thus are not considered cash equivalents.

Total income taxes paid were $372,416,000, $354,981,000 and $217,144,000 for the years ended December 31, 1994, 1993 and 1992, respectively.

Interest paid, net of amounts capitalized, was $236,696,000, $249,659,000 and $303,222,000 for the years ended December 31, 1994, 1993 and 1992, respectively.

NOTE 2. RATE MATTERS

Duke Power Company

The North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC) must approve rates for retail sales within their respective states. The Federal Energy Regulatory Commission (FERC) must approve Duke Power's rates for sales to wholesale customers. Sales to the other joint owners of the Catawba Nuclear Station, which represent a substantial majority of Duke Power's wholesale revenues, are set through contractual agreements. (See Note 3.)

During 1991, Duke Power filed in both the North Carolina and South Carolina retail jurisdictions its only requests for general rate increases since 1986. General rate increases approved in November 1991 resulted in additional annual revenues of $100.1 million and $30.2 million in North Carolina and South Carolina, respectively. The increases were primarily needed to recover costs associated with the construction of the Bad Creek Hydroelectric Station. Also in 1991, Duke Power filed a request for a wholesale rate increase with the FERC. A negotiated settlement between Duke Power and the wholesale customers was approved by the FERC in 1992 and resulted in an increase in annual revenues of $2.1 million.

In 1992, the North Carolina Supreme Court remanded to the NCUC Duke Power's 1986 rate order for the second time. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order in 1992 which resulted in a 1992 refund to North Carolina retail customers of approximately $95 million, including interest.

Fuel costs are reviewed semiannually in the wholesale and South Carolina retail jurisdictions, with provisions for changing such costs in base rates. In the North Carolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings.

All jurisdictions allow Duke Power to adjust rates for past over- or under-recovery of fuel costs. Therefore, Duke Power reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

NOTE 2. RATE MATTERS — Continued

The North Carolina legislature ratified a bill in July 1987 assuring the legality of such adjustments in rates. In 1991, the statute was extended through June 30, 1997.

Duke Power has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

Nantahala Power and Light Company

During 1992, Nantahala Power and Light Company (NP&L) filed an application for a general rate increase with the NCUC. A general rate increase was approved in June 1993 which resulted in additional annual revenues of $4.3 million. Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES

The Company previously sold interests in both units of the Catawba Nuclear Station. The other owners of portions of the Catawba Nuclear Station and supplemental information regarding their ownership are as follows:

Owner	Ownership Interest in the Station
North Carolina Municipal Power Agency Number 1 (NCMPA)	37.5%
North Carolina Electric Membership Corporation (NCEMC)	28.125%
Piedmont Municipal Power Agency (PMPA)	12.5%
Saluda River Electric Cooperative, Inc. (Saluda River)	9.375%

Each owner has provided its own financing for its ownership interest in the station.

The Company retains a 12.5 percent ownership interest in the Catawba Nuclear Station. As of December 31, 1994, $492,429,000 of "Electric plant in service" and "Nuclear fuel" represents the Company's investment in Units 1 and 2. Accumulated depreciation and amortization of $165,568,000 associated with Catawba has been recorded as of year-end. The Company's share of operating costs of Catawba are included in the Consolidated Statements of Income.

In connection with the joint ownership, the Company has entered into contractual agreements with the other joint owners to purchase declining percentages of the generating capacity and energy from the plant. These purchased power agreements were effective beginning with the commercial operation of each unit. Unit 1 and Unit 2 began commercial operation in June 1985 and August 1986, respectively. The purchased power agreements were established for 15 years for NCMPA and PMPA and 10 years for NCEMC and Saluda River. While the purchased power agreements with NCMPA and PMPA extend for 15 years, a significant decrease in the percentage of capacity and energy the Company is obligated to purchase occurs in the 11th calendar year of operation for each unit. This significant decrease occurs in 1995 for Unit 1 and 1996 for Unit 2. Certain provisions in the agreements with NCEMC and Saluda River have moderated the rate of decrease in the percentage of capacity and energy that the Company is obligated to purchase until 1996 when the Company has no further obligation to purchase capacity and related energy.

The agreements also provide for supplemental power sales by the Company to the other joint owners. Such power sales are to satisfy capacity and energy needs of the other joint owners beyond the capacity and energy which they retain from Catawba or potentially acquire in the form of other resources. As the joint owners retain more capacity and energy from Catawba, or a third party, supplemental power sales are expected to decline.

NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES — Continued

The agreements with each of the other joint owners include provisions that the Company will provide generating reserves to backstand the other joint owners' retained capacity in the Catawba plant at the system average cost of installed capacity. Additionally, the agreements include certain reliability exchanges designed to manage outage-related risks by exchanging energy entitlements between the Catawba Nuclear Station and the McGuire Nuclear Station, impacting the Company as well as all the other joint owners.

Energy cost payments are based on variable operating costs and are a function of the generation output of Catawba. Capacity payments are based on the fixed costs of the plant and include the capital costs and fixed operating and maintenance costs. Actual purchased capacity costs for 1994 and projected obligations for 1995 through 1999 are as follows (dollars in thousands):

Year	Purchased Capacity Capital Cost	Purchased Capacity Fixed O&M	Total Purchased Capacity
1994 Actual	$381,419	$126,774	$508,193
1995 Projected	$207,046	$ 91,465	$298,511
1996 Projected	$ 37,376	$ 18,698	$ 56,074
1997 Projected	$ 29,576	$ 15,006	$ 44,582
1998 Projected	$ 21,160	$ 11,459	$ 32,619
1999 Projected	$ 12,693	$ 7,009	$ 19,702

Effective in its November 1991 rate order, the North Carolina Utilities Commission (NCUC) reaffirmed the Company's recovery, on a levelized basis, of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners. The Public Service Commission of South Carolina (PSCSC) in its November 1991 rate order reaffirmed the Company's recovery on a levelized basis of the capital costs of capacity purchased from the other joint owners. Levelization was reaffirmed through inclusion in rates approved in March 1992 by the Federal Energy Regulatory Commission (FERC). The portion of purchased capacity subject to levelization not currently recovered in rates is being deferred, and the Company is recording a return on the accumulated balance. The Company recovers the accumulated balance, including the return, when the sum of the declining purchased capacity payments and accrual of returns for the current period drop below the levelized revenues. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups. The Company recovers the costs of purchased energy and the non-levelized portion of purchased capacity on a current basis.

The current levelized revenues approved in the Company's last general rate proceedings are $211,423,000, $94,137,000 and $6,815,000 for North Carolina retail, South Carolina retail and other wholesale (FERC), respectively. Purchased power costs, subject to levelization, are deferred based on allocation factors of approximately 62 percent, 26 percent and 2 percent for North Carolina retail, South Carolina retail and other wholesale (FERC), respectively. The Company also recovers an allocated amount of purchased power costs in the pricing of supplemental sales made to the other joint owners on a current basis.

In the North Carolina retail and FERC wholesale jurisdictions, purchased capacity payments continue to exceed levelized revenues. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments.

For the years ended December 31, 1994, 1993 and 1992, the Company recorded purchased capacity and energy costs from the other joint owners of $604,505,000, $547,899,000 and $514,327,000, respectively. These amounts, after adjustments for the costs of capacity purchased not reflected in current rates, are included in "Net interchange and purchased power" in the Consolidated Statements of Income. As of December 31, 1994 and 1993, $932,324,000 and $768,099,000, respectively, associated with the cost of capacity purchased but not reflected in current rates have been accumulated in the Consolidated Balance Sheets as "Purchased capacity costs." The cumulative impact of settlement agreements reflected in 1994 resulted in additional purchased capacity costs. (See Note 13.)

NOTE 4. INCOME TAX EXPENSE

The Company implemented Statement of Financial Accounting Standards No. 109 (SFAS 109), "Accounting for Income Taxes," effective January 1, 1993. SFAS 109 requires a liability approach for financial accounting and reporting of income taxes. No prior periods were restated because of the implementation of SFAS 109.

Accumulated deferred income taxes consist primarily of the following temporary differences (dollars in thousands):

	December 31, 1994		December 31, 1993	
Excess tax over book depreciation at historical tax rates	$1,343,605		$1,289,205	
Regulatory liability related to adjusting deferred taxes to the current statutory tax rate	(120,422)*		(124,952)*	
Net excess tax over book depreciation		$1,223,183		$1,164,253
Regulatory asset related to restating to a pre-tax basis		609,714*		611,392*
Deferred Catawba purchased capacity costs		361,018		254,789
Book versus tax basis difference		89,058		110,594
Loss on bond redemptions		70,067		74,438
Other		(4,409)		27,900
Total deferred income taxes		$2,348,631		$2,243,366

* The net regulatory asset related to income taxes is $489,292,000 for 1994 and $486,440,000 for 1993.

Total deferred income tax liability was $2,873,373,000 as of December 31, 1994, and $2,745,431,000 as of December 31, 1993. Total deferred income tax asset was $524,742,000 as of December 31, 1994, and $502,065,000 as of December 31, 1993.

Income tax expense for the years ended December 31, 1994, 1993 and 1992 consisted of the following (dollars in thousands):

	1994	1993	1992
Current income taxes			
Federal	$249,968	$283,930	$209,121
State	52,790	63,150	45,359
Total current income taxes	302,758	347,080	254,480
Deferred taxes, net			
Federal	83,359	59,267	45,820
State	22,153	14,887	14,932
Total deferred taxes, net	105,512	74,154	60,752
Investment tax credit amortization	(11,251)	(11,257)	(11,262)
Total income tax expense	$397,019	$409,977	$303,970

NOTE 4. INCOME TAX EXPENSE — Continued

Income taxes differ from amounts computed by applying the statutory tax rate to pre-tax income for the years ended December 31, 1994, 1993 and 1992 as follows (dollars in thousands):

	1994	1993	1992
Income taxes on pre-tax income at the statutory federal rate of 35% — 1994 and 1993; 34% — 1992	$362,563	$362,737	$276,098
Increase (reduction) in tax resulting from:			
Allowance for funds used during construction (AFUDC)	(9,594)	(6,027)	(7,221)
Amortization of investment tax credit deferrals	(11,251)	(11,257)	(11,262)
AFUDC in book depreciation/amortization	19,027	25,694	25,114
Deferred income tax flowback at rates higher than statutory	(5,530)	(9,091)	(21,685)
State income taxes, net of federal income tax benefits	47,872	51,289	39,407
Other items, net	(6,068)	(3,368)	3,519
Total income tax expense (see above)	$397,019	$409,977	$303,970

NOTE 5. SHORT-TERM BORROWINGS AND COMPENSATING-BALANCE ARRANGEMENTS

At December 31, 1994, the Company had a three-year revolving credit facility of $355,000,000 with 15 commercial banks. At December 31, 1993, the Company had two three-year revolving credit facilities of $300,000,000 and $130,000,000, with 17 and 5 commercial banks, respectively. The Company had $130,000,000 in commercial paper outstanding throughout 1994 and 1993 backed by the unused portion of the above three-year revolving credit facilities. The $130,000,000 in commercial paper is included in long-term debt. In addition, the Company had $44,980,000 in annually renewable lines of credit at December 31, 1994 and 1993. All such facilities are on a fee or compensating-balance basis with the exception of $20,000,000 in annually renewable lines of credit. The amount of short-term debt outstanding from these credit facilities as of December 31, 1994 and 1993 was $10,100,000 and $2,800,000, respectively.

Additionally, as of December 31, 1994 and 1993, the Company had $40,000,000 in pollution-control bonds backed by an unused, two-year revolving credit facility of $40,000,000. This facility is on a fee basis and the bonds are included in long-term debt.

Cash balances maintained at the banks on deposit were $13,214,000 as of December 31, 1994, and $12,988,000 as of December 31, 1993. Cash balances and fees compensate banks for their services, even though the Company has no formal compensating-balance arrangements. To compensate certain banks for credit facilities, the Company maintained balances of $49,000 as of December 31, 1994 and 1993. The Company retains the right of withdrawal with respect to the funds used for compensating-balance arrangements.

A summary of short-term borrowings is as follows (dollars in thousands):

	Twelve Months Ended		
	December 31, 1994	December 31, 1993	December 31, 1992
Amount outstanding at end of period — average rate of 6.02% as of December 31, 1994, 3.55% as of December 31, 1993, and 3.57% as of December 31, 1992	$107,100	$ 20,800	$126,000
Maximum amount outstanding during the period	$143,400	$180,800	$239,950
Average amount outstanding during the period	$ 24,161	$ 35,366	$ 64,050
Weighted-average interest rate for the period — computed on a daily basis	4.58%	3.19%	4.14%

NOTE 6. COMMON STOCK AND RETAINED EARNINGS

Common Stock

The Company issued common stock to satisfy the conversion rights of preference stock through April 6, 1992. (See Note 7.)

As of December 31, 1994, a total of 7,004,659 shares was reserved for issuance to stock plans.

Retained Earnings

As of December 31, 1994, substantially all of the Company's retained earnings were unrestricted as to the declaration or payment of dividends.

NOTE 7. PREFERRED AND PREFERENCE STOCK WITHOUT SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1994 and 1993:

	Par Value	Shares
Preferred Stock	$100	12,500,000
Preferred Stock A	25	10,000,000
Preference Stock	100	1,500,000

On April 6, 1992, the Company redeemed all outstanding shares of the Cumulative Preference Stock, 6¾% Convertible Series AA at its par value of $100 per share.

In 1992, 19,060 shares of preference stock were converted into 159,386 shares of common stock.

Preferred and preference stock without sinking fund requirements as of December 31, 1994 and 1993, were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1994	1993
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
7.85% S	1992	600,000	60,000	60,000
7.00% W	1993	500,000	50,000	50,000
7.04% Y	1993	600,000	60,000	60,000
7.72% (Preferred Stock A)	1992	1,600,000	40,000	40,000
6.375% (Preferred Stock A)	1993	2,400,000	60,000	60,000
Adjustable Rate A	1986	500,000	50,000	50,000
Auction Series A	1990	750,000	75,000	75,000
Total			$500,000	$500,000

NOTE 8. PREFERRED AND PREFERENCE STOCK WITH SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1994 and 1993:

	Par Value	Shares
Preferred Stock	$100	12,500,000
Preferred Stock A	25	10,000,000
Preference Stock	100	1,500,000

NOTE 8. PREFERRED AND PREFERENCE STOCK WITH SINKING FUND REQUIREMENTS — Continued

Preferred and preference stock with sinking fund requirements as of December 31, 1994 and 1993, were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1994	1993
5.95% B (Preferred Stock A)	1992	800,000	$ 20,000	$ 20,000
6.10% C (Preferred Stock A)	1992	800,000	20,000	20,000
6.20% D (Preferred Stock A)	1992	800,000	20,000	20,000
7.12% Q	1987	470,000	47,000	—
		485,000	—	48,500
7.50% R	1992	850,000	85,000	85,000
6.20% T	1992	130,000	13,000	13,000
6.30% U	1992	130,000	13,000	13,000
6.40% V	1992	130,000	13,000	13,000
6.75% X	1993	500,000	50,000	50,000
Less: Current sinking fund requirements				
7.12% Q			(1,500)	(1,500)
Total			$279,500	$281,000

The annual sinking fund requirements through 1999 are $1,500,000 in 1995, 1996 and 1997, $5,750,000 in 1998 and $25,750,000 in 1999. Some additional redemptions are permitted at the Company's option.

The call provisions for the outstanding preferred stock specify various redemption prices not exceeding 105 percent of par value, plus accumulated dividends to the redemption date.

NOTE 9. LONG-TERM DEBT

Long-term debt outstanding as of December 31, 1994 and 1993, was as follows (dollars in thousands):

Series	Year Due	1994	1993
First and Refunding Mortgage Bonds:			
6.06%-6.23%	1994	$ —	$ 81,700
6.47%-6.60%	1995	40,300	40,300
4½%	1995	40,000	40,000
6.59%	1996	3,000	3,000
5⅜%	1997	72,600	72,600
5⅝%	1997	100,000	100,000
5.17%	1998	50,000	50,000
7.5%	1999	100,000	100,000
6¼%	1999	65,000	65,000
5.76%	1999	5,000	5,000
5.78%	1999	25,000	25,000
5.79%	1999	30,000	30,000
8% B	1999	200,000	—
7%	2000	100,000	100,000
7% B	2000	100,000	100,000
5⅞%	2001	150,000	150,000
6⅝% B	2003	100,000	100,000
5⅞% C	2003	75,000	75,000
6.125%	2003	75,000	75,000
8%	2004	75,000	75,000
6¼% B	2004	100,000	100,000
7.37%-7.41%	2004	100,000	100,000
7%	2005	200,000	200,000
6⅜%	2008	125,000	125,000
9⅝%	2020	46,982	46,982
10⅛% B	2020	24,854	24,854
8¼%	2021	150,000	150,000
8⅜% B	2021	150,000	150,000
8⅝%	2022	100,000	100,000
7⅜%	2023	200,000	200,000
6⅞% B	2023	200,000	200,000
7⅞%	2024	150,000	—
6¾%	2025	150,000	150,000
8.95%	2027	15,769	15,851
7%	2033	150,000	150,000
Pollution-Control Bonds:			
7.70%	2012	20,000	20,000
7.75% B	2017	10,000	10,000
7.50%	2017	25,000	25,000
3.69%	2014	40,000	40,000
5.80%	2014	77,000	77,000
Subtotal		3,440,505	3,172,287
Other Long-Term Debt:			
Capitalized leases		26,039	47,029
Other long-term debt		130,000	130,000
Unamortized debt discount and premium, net		(62,918)	(61,128)
Current maturities of long-term debt		(81,926)	(89,156)
Subtotal (a)		3,451,700	3,199,032
Subsidiary Long-Term Debt:			
Crescent Resources, Inc. (b)		92,102	54,149
Nantahala Power and Light (c)		33,653	33,458
Current maturities of long-term debt		(10,333)	(1,242)
Subtotal		115,422	86,365
Total long-term debt		$3,567,122	$3,285,397

(a) Substantially all of Duke Power's electric plant was mortgaged as of December 31, 1994.

(b) Substantial amounts of Crescent Resources, Inc.'s real estate development projects, land and buildings are pledged as collateral.

(c) Nantahala Power and Light's loan agreements impose net worth restrictions and limitations on disposal of assets and payment of cash dividends.

As of December 31, 1994 and 1993, the Company had $40,000,000 in pollution-control revenue bonds backed by an unused, two-year revolving credit facility of $40,000,000. In addition, the Company had $130,000,000 in commercial paper outstanding throughout 1994 and 1993 backed by unused three-year revolving credit facilities. These facilities are on a fee basis. Both the $40,000,000 in pollution-control bonds and the $130,000,000 in commercial paper are included in long-term debt.

NOTE 9. LONG-TERM DEBT — Continued

As of December 31, 1994, Crescent Resources, Inc. had $68,142,000 in mortgage loans which mature through 1999 and $23,960,000 in mortgage loans maturing in 2000 or thereafter, most requiring monthly payments of principal. Interest rates are variable and at December 31, 1994 ranged from 4.50 percent to 7.22 percent. As of December 31, 1994, Nantahala Power and Light Company had $33,000,000 in senior notes maturing in 2011 and 2012. The two notes carry fixed interest rates of 9.21 percent and 7.45 percent and require monthly payments of principal beginning in 1997 and 1998, respectively.

The annual maturities of consolidated long-term debt, including capitalized lease principal payments through 1999, are $92,259,000 in 1995; $12,540,000 in 1996; $212,708,000 in 1997; $62,559,000 in 1998; and $438,490,000 in 1999.

NOTE 10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts of Cash, Short-term investments, Other investments, at cost or less, and Notes payable approximate fair value primarily because of the short maturities of these instruments. The majority of estimated fair value amounts were obtained from independent parties. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 1994 and 1993, are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

External funds have been established, as required by the Nuclear Regulatory Commission, as a mechanism to fund certain costs of nuclear decommissioning. (See Note 14.) Currently, these nuclear decommissioning trust funds are primarily invested in municipal and U.S. government bonds. "Nuclear decommissioning trust funds" are presented on the Consolidated Balance Sheets at amounts that approximate fair value.

The carrying amounts and estimated fair values of long-term debt and preferred stocks are as follows (dollars in thousands):

	December 31, 1994		December 31,1993	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$3,696,260	$3,392,000	$3,389,894	$3,460,000
Preferred stock	$ 781,000	$ 697,000	$ 782,500	$ 801,000

In order to obtain variable rate financing at an attractive cost, the Company has entered into an interest rate swap agreement associated with the issuance on November 29, 1994, of $200,000,000 aggregate principal amount of its First and Refunding Mortgage Bonds, 8% Series B due 1999. The five-year interest rate swap is tied to the London Interbank Offered Rate (LIBOR), which is reset quarterly, and initially was set at 5.95%. As a result of the interest rate swap contract, interest expense on the Consolidated Statements of Income is recognized at the weighted average rate for the year tied to the LIBOR rate.

The Company has also entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Japanese yen associated with various steam generator contracts. The Company records any gains or losses associated with the hedge as an adjustment to the capitalized cost of the steam generators.

NOTE 11. INVESTMENT IN JOINT VENTURES

Certain investments in joint ventures are accounted for by the equity method. The Company's ownership in domestic and international joint ventures is 50 percent or less. The Company's proportionate share of net income in joint ventures for the years ended December 31, 1994, 1993 and 1992 was $7,049,000, $2,601,000 and ($1,179,000), respectively. These amounts are reflected in Operating revenues on the Consolidated Statements of Income. A summary of assets and liabilities of joint ventures follows (dollars in thousands):

	December 31, 1994		December 31, 1993	
	Total	Company's Proportionate Share	Total	Company's Proportionate Share
Assets of joint ventures	$1,117,449	$272,836	$972,315	$241,460
Liabilities of joint ventures	$ 504,029	$164,506	$413,453	$139,848

Of the $504,029,000 and $413,453,000 of total liabilities outstanding at December 31, 1994 and 1993, respectively, $407,605,000 and $290,178,000 represent non-recourse debt at December 31, 1994 and 1993, respectively, for which the Company bears no responsibility beyond the loss of its investment in the event the joint venture defaults on the debt.

NOTE 12. RETIREMENT BENEFITS

A. Retirement Plan

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own retirement plans, have a non-contributory, defined benefit retirement plan covering substantially all their employees. The benefit is based upon an age-related formula which takes into account years of creditable service and the employee's average compensation based upon the highest compensation during a consecutive sixty-month period. The benefit is reduced by an adjustment which is based upon the employee's social security wages. Normal retirement age under the Plan is age 65; however, early retirement benefits are payable as early as age 55 with 10 years of creditable service or age 51 if the employee has at least 30 years of creditable service. The Company's policy is to fund pension costs as accrued. During 1994 and 1993, the Company made additional contributions of $30,000,000 and $50,000,000, respectively, to enhance the funded position of the plan.

Net periodic pension cost for the years ended December 31, 1994, 1993 and 1992, include the following components (dollars in thousands):

	1994	1993	1992
Service cost benefit earned during the year	$ 43,098	$ 39,514	$ 35,701
Interest cost on projected benefit obligation	96,521	93,347	85,613
Actual return on plan assets	(6,138)	(117,898)	(50,897)
Amount deferred for recognition	(86,995)	35,652	(32,277)
Expected return on plan assets	(93,133)	(82,246)	(83,174)
Net amortization	7,657	4,137	3,812
Net periodic pension cost	$ 54,143	$ 54,752	$ 41,952

NOTE 12. RETIREMENT BENEFITS — Continued

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1994 and 1993, is as follows (dollars in thousands):

	1994	1993
Accumulated benefit obligation:		
Vested benefits	$(1,070,355)	$(1,087,705)
Nonvested benefits	(4,420)	(3,946)
Accumulated benefit obligation	$(1,074,775)	$(1,091,651)
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$ 1,167,158	$ 1,137,992
Projected benefit obligation	(1,368,740)	(1,311,921)
Unrecognized net experience loss	319,519	265,566
Unrecognized prior service cost reduction	(38,872)	(42,705)
Remaining unrecognized transitional obligation	935	1,068
Pre-funded pension cost	$ 80,000	$ 50,000

In determining the projected benefit obligation, the weighted-average assumed discount rate used was 8.25 percent in 1994, 7.50 percent in 1993 and 8.25 percent in 1992. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 5.40 percent in 1994, 4.50 percent in 1993 and 5.40 percent in 1992. The expected long-term rate of return on plan assets used in determining pension cost was 9.00 percent in 1994, 8.40 percent in 1993 and 9.25 percent in 1992.

During 1993, the Company offered an enhanced early retirement option, Limited Period Separation Opportunity (LPSO), for eligible employees. The Company recorded an additional one-time expense for special termination benefits associated with LPSO of approximately $7,611,000.

B. Postretirement Benefits

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own postretirement benefit plans, currently provides certain health care and life insurance benefits for retired employees. Employees become eligible for these benefits if they retire at age 55 or greater with 10 years of service or if they retire as early as age 51 with 30 years or more of service. Employees retiring after January 1, 1992, receive a fixed Company allowance, based on years of service, to be used to pay medical insurance premiums. The Company reserves the right to terminate, suspend, withdraw, amend or modify the plans in whole or in part at any time.

In 1992, the Company commenced funding the maximum amount allowable under section 401(h) of the Internal Revenue Code, which provides for tax deductions for contributions and tax-free accumulation of investment income. Such amounts partially fund the Company's medical and dental postretirement benefits. The Company has also established a Retired Lives Reserve, which has tax attributes similar to 401(h) funding, to partially fund its postretirement life insurance obligation. The Company contributed $12,269,000 into these funding mechanisms in 1994 and $14,648,000 in 1993.

NOTE 12. RETIREMENT BENEFITS — Continued

Net periodic postretirement benefit cost for the years ended December 31, 1994, 1993 and 1992 include the following components (dollars in thousands):

	1994	1993	1992
Service cost benefit earned during the year	$ 5,415	$ 4,974	$ 4,644
Interest cost on accumulated postretirement benefit obligation	25,321	25,482	23,347
Actual return on plan assets	(1,451)	(4,143)	(2,953)
Amount deferred for recognition	(3,469)	334	1,061
Expected return on plan assets	(4,920)	(3,809)	(1,892)
Straight-line — 20 year amortization of transitional obligation	13,293	13,479	13,479
Other amortization	366	278	160
Net periodic postretirement benefit cost	$39,475	$40,404	$39,738

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1994 and 1993, is as follows (dollars in thousands):

	1994	1993
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$ 69,987	$ 57,840
Actives eligible to retire	(11,902)	(21,810)
Actives not eligible to retire	(90,499)	(90,621)
Retirees and surviving spouses	(239,978)	(238,522)
Accumulated postretirement benefit obligation	(342,379)	(350,953)
Unrecognized prior service cost	783	1,923
Unrecognized net experience (gain)/loss	14,448	29,127
Unrecognized transitional obligation	225,988	242,629
(Accrued) postretirement benefit cost	$ (31,173)	$ (19,434)

In determining the accumulated postretirement benefit obligation (APBO), the weighted-average assumed discount rate used was 8.25 percent in 1994, 7.50 percent in 1993 and 8.25 percent in 1992. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 5.40 percent in 1994, 4.50 percent in 1993 and 5.40 percent in 1992. The expected long-term rate of return on 401(h) assets used in determining postretirement benefits cost was 9.00 percent in 1994, 8.40 percent in 1993 and 9.25 percent in 1992. For Retired Lives Reserve assets, 6.50 percent was used in 1994 and 7.125 percent was used in 1993 and 1992.

The assumed medical inflation rate was approximately 12.50 percent in 1994. This rate decreases by 0.5 percent to 1.0 percent per year until a rate of 5.5 percent is achieved in the year 2002, which remains fixed thereafter.

A 1.0 percent increase in the medical and dental trend rates produces a 5.05 percent ($1,552,000) increase in the aggregate service and interest cost. The increase in the APBO attributable to a 1.0 percent increase in the medical and dental trend rates is 4.10 percent ($14,029,000) as of December 31, 1994.

NOTE 13. COMMITMENTS AND CONTINGENCIES

A. Construction Program

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including allowance for funds used during construction, are $3.0 billion and $620 million, respectively, for 1995 through 1999. Projected capital expenditures of subsidiaries and diversified activities are $661 million for 1995 through 1999. These projections are subject to

NOTE 13. COMMITMENTS AND CONTINGENCIES — Continued

periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

B. Nuclear Insurance

The Company maintains nuclear insurance coverage in three areas: liability coverage, property, decontamination and decommissioning coverage, and extended accidental outage coverage to cover increased generating costs and/or replacement power purchases. The Company is being reimbursed by the other joint owners of the Catawba Nuclear Station for certain expenses associated with nuclear insurance premiums paid by the Company.

Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $8.9 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $8.7 billion, which will be increased by $79.3 million as each additional commercial nuclear reactor is licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. The $8.7 billion could also be reduced by $79.3 million for certain nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs and public liability damages exceed primary insurances, licensees may be assessed up to $79.3 million for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $79.3 million amount is subject to indexing for inflation and may be subject to state premium taxes. This amount is further subject to a surcharge of 5 percent (which is included in the above $8.7 billion figure) if funds are insufficient to pay claims and associated costs. If retrospective premiums were to be assessed, the other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of such assessment.

The Company is a member of Nuclear Mutual Limited (NML), which provides $500 million in primary property damage coverage for each of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $36 million. This amount represents 5 times the Company's annual premium to NML. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NML policies applicable to Catawba.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. NEIL provides excess insurance coverage of $2.25 billion for the Catawba Nuclear Station and $1.5 billion for each of the Oconee and McGuire Nuclear Stations. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, the Company will be liable, on a pro rata basis, for additional assessments of up to $62 million. This amount is limited to 7.5 times the Company's annual premium to NEIL for excess property, decontamination and decommissioning liability insurance. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to Catawba. The Company has also purchased an additional $850 million of excess property damage insurance for its Catawba plant through a pool of stock and mutual insurance companies.

The Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Each unit of the Oconee, McGuire and Catawba Nuclear Stations is insured for up to approximately $3.5 million per week, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100 percent for 52 weeks and 80 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $30 million. This amount represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage

NOTE 13. COMMITMENTS AND CONTINGENCIES — Continued

of a nuclear unit. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to the joint ownership agreements.

C. Other

The other joint owners of the Catawba Nuclear Station and the Company were involved in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information, see Note 3.) The Company and the other joint owners entered into settlement agreements in 1994 which resolved all issues in contention in the proceedings. The Company has settled its cumulative net obligation through 1993 of approximately $205 million with the other joint owners. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because it expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, the Company has included approximately $205 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5 "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or financial position of the Company.

NOTE 14. NUCLEAR DECOMMISSIONING COSTS

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the North Carolina Utilities Commission and the Public Service Commission of South Carolina have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume each unit will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021, McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The Nuclear Regulatory Commission issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1994, the Company expensed approximately $52,524,000 which was contributed to the external funds and accrued an additional $4,841,000 to the internal reserve. Nuclear units are depreciated at a rate of 4.70 percent, of which 1.61 percent is for decommissioning. The balance of the external funds as of December 31, 1994, was $172,390,000. The balance of the internal reserve as of December 31, 1994, was $204,837,000 and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

NOTE 15. RECLASSIFICATION

In the Consolidated Statements of Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows, certain prior-year information has been reclassified to conform with 1994 classifications.

INDEPENDENT AUDITORS' REPORT

Duke Power Company:

We have audited the consolidated financial statements of Duke Power Company and subsidiaries (the Company) listed in the accompanying index on page 23. Our audits also included the consolidated financial statement schedule listed in the accompanying index on page 23. These financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1994 and 1993, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1994 in conformity with generally accepted accounting principles. Also, in our opinion, such consolidated financial statement schedule when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

Charlotte, North Carolina
February 10, 1995

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Power Company are prepared by management, which is responsible for their integrity and objectivity. The statements are prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions which should be included. The other information in the annual report is consistent with the financial statements. In preparing these statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed according to management's authorization. Internal accounting controls also provide reasonable assurance that transactions are recorded properly, so that financial statements can be prepared according to generally accepted accounting principles. In addition, the Company's accounting controls provide reasonable assurance that errors or irregularities which could be material to the financial statements are prevented or are detected by employees within a timely period as they perform their assigned functions. The Company's accounting controls are continually reviewed for effectiveness. In addition, written policies, standards and procedures, and a strong internal audit program augment the Company's accounting controls.

The Board of Directors pursues its oversight role for the financial statements through the Audit Committee, which is composed entirely of directors who are not employees of the Company. The Audit Committee meets with management and internal auditors periodically to review the work of each group and to monitor each group's discharge of its responsibilities. The Audit Committee also meets periodically with the Company's independent auditors, Deloitte & Touche LLP. The independent auditors have free access to the Audit Committee and the Board of Directors to discuss internal accounting control, auditing and financial reporting matters without the presence of management.

JEFFREY L. BOYER
Controller

DE00000518

SELECTED QUARTERLY FINANCIAL DATA
(Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	Dollars in Thousands (except per-share data)				
1994 by quarter					
Operating revenues	$1,099,002	$1,083,310	$1,272,525	$1,034,076	$4,488,913
Operating income	$ 326,584	$ 242,419	$ 430,861	$ 179,962	$1,179,826
Net income	$ 173,617	$ 128,002	$ 243,741	$ 93,516	$ 638,876
Earnings per share	$ 0.79	$ 0.56	$ 1.13	$ 0.40	$ 2.88
1993 by quarter					
Operating revenues	$1,048,365	$1,034,371	$1,340,657	$1,042,840	$4,466,233
Operating income	$ 276,637	$ 246,748	$ 451,028	$ 233,398	$1,207,811
Net income	$ 141,684	$ 122,470	$ 241,409	$ 120,852	$ 626,415
Earnings per share	$ 0.63	$ 0.53	$ 1.12	$ 0.52	$ 2.80

Generally, quarterly earnings fluctuate with seasonal weather conditions and maintenance of electric generating units, especially nuclear units.

SUBSIDIARIES AND DIVERSIFIED ACTIVITIES HIGHLIGHTS

During 1994, the Company reorganized, placing all its subsidiaries and diversified activities into the Associated Enterprises Group (AEG). AEG includes the following:

- **Church Street Capital Corp.** (CSCC) manages investment funds and serves as the parent company for the non-electric operating subsidiaries. CSCC investment highlights are as follows (dollars in thousands):

  Short-term investments and marketable securities

1994	1993	1992
$170,642	$155,871	$173,347

  Investment income (after tax) (a)

1994	1993	1992
$7,562	$3,548	$5,404

- **Crescent Resources, Inc.** is engaged in real estate development and forest management.
- **Duke Energy Group, Inc.**, parent of Duke Energy Corp., structures, finances and manages investments in electric generation and transmission facilities, both nationally and internationally.
- **Duke Engineering & Services, Inc.** markets engineering, construction, quality assurance, consulting and other engineering-related services for facilities other than coal-fired generating plants, both nationally and internationally.
- **Duke/Fluor Daniel**, a joint venture with Fluor Daniel, Inc., provides engineering, construction, and support of operating and maintenance activities, primarily for coal-fired generating plants, both nationally and internationally.
- **Duke Merchandising** sells and services quality electric merchandise and electronics primarily to Duke Power customers.
- **DukeNet Communications, Inc.** develops and manages communication systems.
- **Duke Water Operations** serves areas of Anderson, South Carolina, and Rutherfordton, North Carolina.
- **Nantahala Power and Light Company** provides electric service to a five-county area in western North Carolina by its operation of eleven hydroelectric stations and purchase of supplemental power.

Operating Results

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Operating revenues			
Crescent Resources, Inc.	$ 64,724	$ 46,784	$ 44,788
Duke Energy Group, Inc. (b)	9,478	6,033	1,805
Nantahala Power and Light Company (c)	68,595	67,142	60,183
All Other Business Units (d)	109,932	106,340	92,613
Total Associated Enterprises Group	$252,729	$226,299	$199,389
Operating income			
Crescent Resources, Inc.	$ 46,236	$ 30,004	$ 30,602
Duke Energy Group, Inc.	(1,035)	(2,929)	(3,474)
Nantahala Power and Light Company	12,224	8,844	6,937
All Other Business Units (d)	15,506	1,939	8,743
Total Associated Enterprises Group	$ 72,931	$ 37,858	$ 42,808
Net income			
Crescent Resources, Inc.	$ 26,525	$ 16,327	$ 16,613
Duke Energy Group, Inc. (e)	5,749	(1,949)	(2,239)
Nantahala Power and Light Company	6,169	4,261	3,526
All Other Business Units (d)	13,593	2,876	7,458
Total Associated Enterprises Group	$ 52,036	$ 21,515	$ 25,358

Financial Position

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Total assets			
Crescent Resources, Inc.	$294,175	$219,206	$195,476
Duke Energy Group, Inc. (f)	110,656	144,499	25,876
Nantahala Power and Light Company	125,883	107,872	94,531
All Other Business Units (d)	279,430	265,977	314,783
Total Associated Enterprises Group	$810,144	$737,554	$630,666
Total liabilities			
Crescent Resources, Inc.	$134,574	$ 86,172	$ 84,526
Duke Energy Group, Inc.	4,672	31,816	3,108
Nantahala Power and Light Company	72,542	60,700	51,620
All Other Business Units (d)	22,312	30,902	29,495
Total Associated Enterprises Group	$234,100	$209,590	$168,749

Cash Flows

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Cash provided by (used in) operating activities			
Crescent Resources, Inc.	$ 37,691	$ 36,254	$ 25,926
Duke Energy Group, Inc.	(6,614)	(1,438)	(1,936)
Nantahala Power and Light Company	12,817	14,869	7,039
All Other Business Units (d)	10,589	8,795	32,719
Total Associated Enterprises Group	$ 54,483	$ 58,480	$ 63,748
Cash provided by investing activities			
Crescent Resources, Inc.	$ 2,524	$ 1,310	$ 122
Duke Energy Group, Inc. (g)	40,740	28,785	—
Nantahala Power and Light Company	—	—	—
All Other Business Units (h)	5,100	21,377	3,168
Total Associated Enterprises Group	$ 48,364	$ 51,472	$ 3,290
Cash used in investing activities			
Crescent Resources, Inc.	$ 78,689	$ 43,444	$ 21,910
Duke Energy Group, Inc.	19,575	116,498	22,147
Nantahala Power and Light Company	23,989	19,254	12,746
All Other Business Units (i)	18,500	1,450	55,756
Total Associated Enterprises Group	$140,753	$180,646	$112,559
Cash provided by (used in) financing activities (j)			
Crescent Resources, Inc. (k)	$ 37,589	$ 945	$ (8,993)
Duke Energy Group, Inc. (l)	—	—	—
Nantahala Power and Light Company	10,896	3,206	7,184
All Other Business Units (m)	(6,993)	71,537	54,979
Total Associated Enterprises Group	$ 41,492	$ 75,688	$ 53,170

Other Information

	December 31,		
	1994	1993	1992
Full-time employees at year-end			
Crescent Resources, Inc.	89	77	73
Duke Energy Corp.	35	24	18
Nantahala Power and Light Company	184	194	191
All Other Business Units	703	755	777
Total Associated Enterprises Group	1,011	1,050	1,059

(a) Earnings for 1994, 1993 and 1992 exclude elimination of intercompany profits of $49,000, $509,000 and $1,211,000, respectively.

(b) Includes Duke Energy Group, Inc.'s allocable share of net income from joint ventures. (See "Note 11, Notes to Consolidated Financial Statements.")

(c) Nantahala Power and Light Company's Operating revenues include revenues from the sale of electricity to Duke Power of $12,131,000, $13,683,000 and $12,640,000 for 1994, 1993 and 1992, respectively.

(d) All Other Business Units amounts include Associated Enterprises Group intercompany eliminations.

(e) 1994 includes a gain of $4,800,000, after tax, from the sale of preferred stock.

(f) Includes Duke Energy Group, Inc.'s investments in joint ventures. (See "Note 11, Notes to Consolidated Financial Statements.")

(g) 1994 includes proceeds from the sale of preferred stock of $32,468,000 and debt securities of $3,360,000. 1993 includes proceeds from the sale of debt securities of $19,654,000.

(h) 1993 includes the net change in short-term investments for the period of $20,653,000.

(i) 1994 and 1992 include the net change in short-term investments for the period of $12,060,000 and $49,282,000, respectively.

(j) Excludes capital infusion and return of capital transactions between Church Street Capital Corp. and its subsidiaries.

(k) 1993 and 1992 exclude capital infusions from parent, Church Street Capital Corp., of $6,000,000 and $5,000,000, respectively.

(l) 1994 excludes net return of capital to parent, Church Street Capital Corp., of $12,100,000. 1993 and 1992 exclude net capital infusions from Church Street Capital Corp. of $91,864,000 and $24,360,000, respectively.

(m) 1993 and 1992 each include capital infusions from Duke Power to Church Street Capital Corp. of $75,000,000.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Description	Balance Beginning of Year	Balance End of Year
	Dollars in Thousands	
For the Year Ended December 31, 1994		
Reserves Related to Assets on Balance Sheet	$ 10,353	$ 8,059
Other Reserves		
Operating Reserves (1)	107,477	154,722
For the Year Ended December 31, 1993		
Reserves Related to Assets on Balance Sheet	10,730	10,353
Other Reserves		
Operating Reserves (1)	78,103	107,477
For the Year Ended December 31, 1992		
Reserves Related to Assets on Balance Sheet	25,592	10,730
Other Reserves		
Operating Reserves (1)	67,577	78,103

(1) Principally consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits and Other Liabilities" in the Consolidated Balance Sheets.

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Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

No events necessary to be disclosed by the Company under this item have occurred.

PART III.

Item 10. ***Directors and Executive Officers of the Registrant.***

Information for this item concerning directors of the Company is set forth in the sections entitled "Election of Directors", "Information Regarding the Board of Directors" and "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1995 annual meeting of shareholders, which are being incorporated herein by reference.

Information concerning the executive officers of the Company is set forth in the section entitled "Executive Officers of the Company" in this annual report.

Item 11. ***Executive Compensation.***

Information for this item is set forth in the section entitled "Executive Compensation" in the proxy statement of the Company relating to its 1995 annual meeting of shareholders, which is being incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management.***

Information for this item is set forth in the section entitled "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1995 annual meeting of shareholders, which is being incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions.***

Information for this item is set forth in the sections entitled "Information Regarding the Board of Directors" and "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1995 annual meeting of shareholders, which are being incorporated herein by reference.

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PART IV.

Item 14. *Exhibits, Consolidated Financial Statement Schedules, and Reports on Form 8-K.*

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Consolidated Financial Statements

Consolidated Statements of Income for the Three Years Ended December 31, 1994

Consolidated Statements of Retained Earnings for the Three Years Ended December 31, 1994

Consolidated Statements of Cash Flows for the Three Years Ended December 31, 1994

Consolidated Balance Sheets — December 31, 1994 and 1993

Notes to Consolidated Financial Statements

Selected Quarterly Financial Data (Unaudited)

Consolidated Financial Statement Schedule

Schedule II — Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 1994

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

(b) Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1994.

(c) Exhibits — See Exhibit Index on page 54.

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Charlotte and State of North Carolina on the 29th day of March, 1995.

DUKE POWER COMPANY
(Registrant)

By: W. H. GRIGG
Chairman of the Board and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
W. H. GRIGG	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	March 29, 1995
RICHARD J. OSBORNE	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 29, 1995
JEFFREY L. BOYER	Controller (Principal Accounting Officer)	March 29, 1995
G. ALEX BERNHARDT CRANDALL C. BOWLES W. A. COLEY STEVE C. GRIFFITH, JR. W. H. GRIGG PAUL H. HENSON JAMES V. JOHNSON GEORGE DEAN JOHNSON, JR. W. W. JOHNSON MAX LENNON JAMES G. MARTIN BUCK MICKEL R. B. PRIORY RUSSELL M. ROBINSON, II	A Majority of the Directors	March 29, 1995

ELLEN T. RUFF, by signing her name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

/s/ ELLEN T. RUFF
Ellen T. Ruff, Attorney-In-Fact

EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the Securities and Exchange Commission and pursuant to Rule 12b-32 are incorporated herein by reference.

Exhibit Number	
3-A	—Restated Articles of Incorporation of registrant, dated as of October 6, 1993 (filed with Form S-3, File No. 33-50617, effective October 20, 1993, as Exhibit 4(A)).
3-B	—Articles of Amendment of registrant dated November 1, 1993, relating to the 6.375% Cumulative Preferred Stock A, 1993 Series (filed with Form S-3, No. 33-52479, effective March 29, 1994, as Exhibit 4(B)).
3-C	—By-Laws of registrant, as amended (filed with Form S-3, No. 33-50584, effective August 11, 1992, as Exhibit 3(g)).
4-B-1	—First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated as of December 1, 1927 (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(a)).
4-B-2	—Supplemental Indenture, dated as of March 12, 1930, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).
4-B-3	—Supplemental Indenture, dated as of July 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(c)).
4-B-4	—Supplemental Indenture, dated as of December 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(d)).
4-B-5	—Supplemental Indenture, dated as of September 1, 1936, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).
4-B-6	—Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).
4-B-7	—Supplemental Indenture, dated as of April 1, 1944 supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).
4-B-8	—Supplemental Indenture, dated as of September 1, 1947 supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).
4-B-9	—Supplemental Indenture, dated as of September 8, 1947 supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).
4-B-10	—Supplemental Indenture, dated as of February 1, 1949 supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).
4-B-11	—Supplemental Indenture, dated as of March 1, 1949 supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).
4-B-12	—Supplemental Indenture, dated as of April 1, 1951 supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(l)).
4-B-13	—Supplemental Indenture, dated as of September 1, 1953 supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-13).
4-B-14	—Supplemental Indenture, dated as of October 1, 1954 supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).
4-B-15	—Supplemental Indenture, dated as of January 1, 1955 supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-15).
4-B-16	—Supplemental Indenture, dated as of May 1, 1956 supplementing said Mortgage (filed with Form S-9, File No. 2-12402 effective April 26, 1956, as Exhibit 2-B-16).
4-B-17	—Supplemental Indenture, dated as of January 1, 1960 supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).
4-B-18	—Supplemental Indenture, dated as of February 1, 1960 supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).
4-B-19	—Supplemental Indenture, dated as of February 1, 1962 supplementing said Mortgage (filed with Form S-9, File No. 2-20577, effective August 16, 1962, as Exhibit 2-B-20).
4-B-20	—Supplemental Indenture, dated as of August 1, 1962 supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-19).
4-B-21	—Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 3, 1966, as Exhibit 4-B-20).

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Exhibit Number	
4-B-22	—Supplemental Indenture, dated as of February 1, 1965, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-21).
4-B-23	—Supplemental Indenture, dated as of April 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-28023, effective February 15, 1968, as Exhibit 2-B-25).
4-B-24	—Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No. 2-31304, effective January 21, 1969, as Exhibit 2-B-26).
4-B-25	—Supplemental Indenture, dated as of February 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-34289, effective August 27, 1969, as Exhibit 2-B-27).
4-B-26	—Supplemental Indenture, dated as of September 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-36095, effective February 16, 1970, as Exhibit 2-B-39).
4-B-27	—Supplemental Indenture, dated as of March 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-37953, effective July 28, 1970, as Exhibit 2-B-42).
4-B-28	—Supplemental Indenture, dated as of August 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-39451, effective March 4, 1971, as Exhibit 2-B-28).
4-B-29	—Supplemental Indenture, dated as of March 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-42404, effective December 7, 1971, as Exhibit 2-B-29).
4-B-30	—Supplemental Indenture, dated as of December 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-43122, effective March 7, 1972, as Exhibit 2-B-30).
4-B-31	—Supplemental Indenture, dated as of April 1, 1972, supplementing said Mortgage (filed with Form S-7 File No. 2-46208, effective November 20, 1972, as Exhibit 2-B-31).
4-B-32	—Supplemental Indenture, dated as of December 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-48058, effective June 5, 1973, as Exhibit 2-B-32).
4-B-33	—Supplemental Indenture, dated as of June 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-49333, effective November 5, 1973, as Exhibit 2-B-33).
4-B-34	—Supplemental Indenture, dated as of November 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-50493, effective April 25, 1974, as Exhibit 2-B-34).
4-B-35	—Supplemental Indenture, dated as of May 1, 1974, supplementing said Mortgage (filed with Form S-7, File No. 2-52669, effective February 11, 1975, as Exhibit 2-B-35).
4-B-36	—Supplemental Indenture, dated as of February 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-36).
4-B-37	—Supplemental Indenture, dated as of July 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-37).
4-B-38	—Supplemental Indenture, dated as of October 1, 1976, supplementing said Mortgage (filed with Form S-7, File No. 2-59494, effective August 10, 1977, as Exhibit 2-B-38).
4-B-39	—Supplemental Indenture, dated as of September 1, 1977, supplementing said Mortgage (filed with Form S-7, File No. 2-61995, effective July 26, 1978, as Exhibit 2-B-39).
4-B-40	—Supplemental Indenture, dated as of August 1, 1978, supplementing said Mortgage (filed with Form S-7, File No. 2-64541, effective June 7, 1979, as Exhibit 2-B-40).
4-B-41	—Supplemental Indenture, dated as of June 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-65371, effective October 2, 1979, as Exhibit 2-B-41).
4-B-42	—Supplemental Indenture, dated as of October 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-66659, effective March 12, 1980, as Exhibit 2-B-42).
4-B-43	—Supplemental Indenture, dated as of March 1, 1980, supplementing said Mortgage (filed with Form S-16, File No.2-68571, effective August 19, 1980, as Exhibit 2-B-43).
4-B-44	—Supplemental Indenture, dated as of August 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-44).
4-B-45	—Supplemental Indenture, dated as of March 1, 1982, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-45).
4-B-46	—Supplemental Indenture, dated as of September 1, 1982, supplementing said Mortgage (filed with Form S-3, File No. 2-78882, effective August 30, 1982, as Exhibit 4-B-46).
4-B-47	—Supplemental Indenture, dated as of May 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-47).
4-B-48	—Supplemental Indenture, dated as of September 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-48).
4-B-49	—Supplemental Indenture, dated as of September 1, 1984, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-49).
4-B-50	—Supplemental Indenture, dated as of March 1, 1985, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-50).

Exhibit Number	
4-B-51	—Supplemental Indenture, dated as of December 1, 1985, supplementing said Mortgage (filed with Form S-3, File No. 33-5163, effective May 2, 1986, as Exhibit 4-B-51).
4-B-52	—Supplemental Indenture, dated as of April 1, 1986, supplementing said Mortgage (filed with Form S-3, File No. 33-5163, effective May 2, 1986, as Exhibit 4-B-52).
4-B-53	—Supplemental Indenture, dated as of May 1, 1986, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-53).
4-B-54	—Supplemental Indenture, dated as of June 1, 1986, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-54).
4-B-55	—Supplemental Indenture, dated as of February 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-55).
4-B-56	—Supplemental Indenture, dated as of February 15, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-56).
4-B-57	—Supplemental Indenture, dated as of March 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-57).
4-B-58	—Supplemental Indenture, dated as of October 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1987, File No. 1-4928, as Exhibit 4-B-58).
4-B-59	—Supplemental Indenture, dated as of February 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1989, File No. 1-4928, as Exhibit 4-B-59).
4-B-60	—Supplemental Indenture, dated as of March 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-60).
4-B-61	—Supplemental Indenture, dated as of May 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-61).
4-B-62	—Supplemental Indenture, dated as of May 15, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-62).
4-B-63	—Supplemental Indenture, dated as of March 1, 1991, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-63).
4-B-64	—Supplemental Indenture, dated as of July 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-64).
4-B-65	—Supplemental Indenture, dated as of December 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-65).
4-B-66	—Supplemental Indenture, dated as of March 1, 1992, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1991, File No. 1-4928, as Exhibit 4-B-66).
4-B-67	—Supplemental Indenture, dated as of June 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-67).
4-B-68	—Supplemental Indenture, dated as of July 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-68).
4-B-69	—Supplemental Indenture, dated as of September 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-53308, effective November 24, 1992, as Exhibit 4-B-69).
4-B-70	—Supplemental Indenture, dated as of February 1, 1993, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, as Exhibit 4-B-70).
4-B-71	—Supplemental Indenture, dated as of March 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-59448, effective March 17, 1993, as Exhibit 4-B-71).
4-B-72	—Supplemental Indenture, dated as of April 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-72).
4-B-73	—Supplemental Indenture, dated as of May 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-73).
4-B-74	—Supplemental Indenture, dated as of June 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-74).
4-B-75	—Supplemental Indenture, dated as of July 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-75).
4-B-76	—Supplemental Indenture, dated as of August 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-76).
4-B-77	—Supplemental Indenture, dated as of August 20, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-77).
*4-B-78	—Supplemental Indenture, dated as of May 1, 1994, supplementing said Mortgage.
*4-B-79	—Supplemental Indenture, dated as of November 1, 1994, supplementing said Mortgage.

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Exhibit Number	
*4-C	—Instrument of Resignation, Appointment and Acceptance among Duke Power Company, Morgan Guaranty Trust Company of New York, as Trustee, and Chemical Bank, as Successor Trustee, dated as of August 30, 1994.
10-A	—Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).
10-B	—Agreement, dated August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).
10-C	—Agreement, dated October 14, 1980 between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-D	—Agreement, dated October 14, 1980 between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-E†	—Employees' Stock Ownership Plan.
10-F††	—Employee Incentive Plan.
10-G††	—1993 Executive Long-Term Incentive Plan.
10-H†	—Supplemental Security Plan.
10-I†	—Stock Purchase-Savings Program for Employees.
10-J†	—Employees' Retirement Plan.
10-K†	—Supplemental Retirement Plan.
10-L†	—Compensation Deferral Plan.
10-M†	—Compensation Deferral Plan for Outside Directors.
10-N†	—Retirement Plan for Outside Directors.
10-O†	—Supplementary Defined Contribution Plan for Employees.
10-P†	—Directors' Charitable Giving Program.
10-Q†	—Vacation Banking Plan.
10-R†	—Estate Conservation Plan.
10-S†	—Supplemental Insurance Plan.
10-T†	—Group Life Insurance Plan.
10-U†	—Stock Ownership Plan for Nonemployee Directors.
*10-V	—Executive Short-Term Incentive Plan.
*10-W	—Executive Long-Term Incentive Plan.
*12	—Computation of Ratio of Earnings to Fixed Charges.
*23	—Consent of Independent Auditors.
*24(a)	—Power of attorney authorizing Ellen T. Ruff and others to sign the annual report on behalf of the registrant and certain of its directors and officers.
*24(b)	—Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.
*27	—Financial Data Schedule.

† Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, under the same exhibit number as listed herein.

†† Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1993, File No. 1-4928, under the same exhibit number as listed herein.

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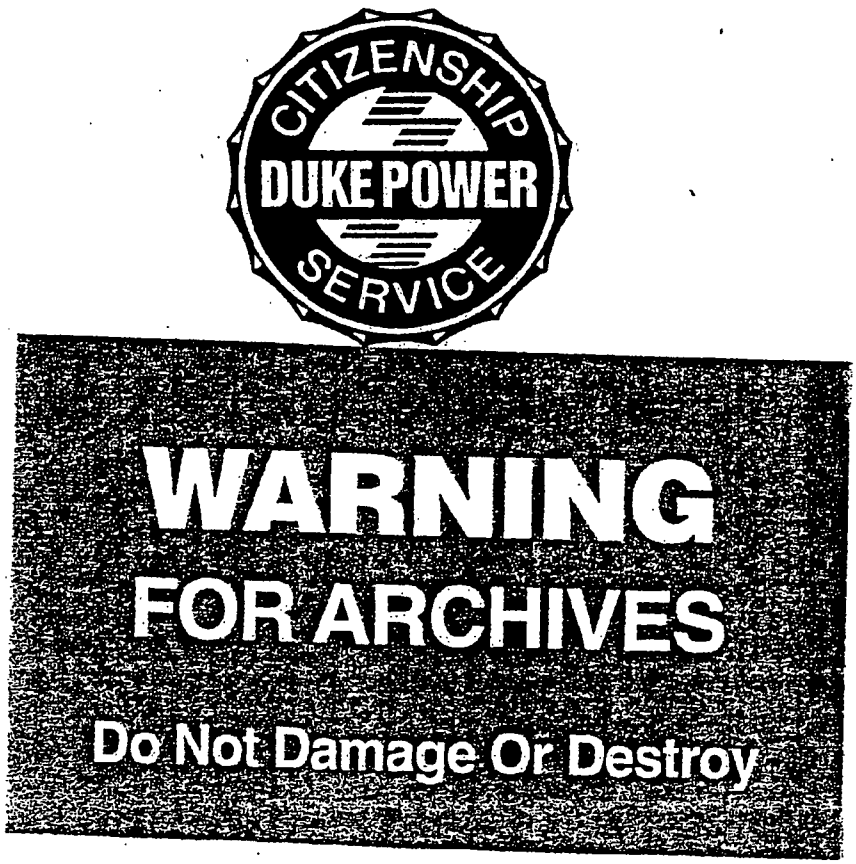
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EXHIBIT 12

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in Thousands)

	Year Ended December 31				
	1994	1993	1992	1991	1990
Earnings Before Income Tax	$1,035,895	$1,036,392	$ 812,053	$ 876,641	$ 788,182
Fixed Charges	278,117	281,428	326,575	310,030	296,874
Total	$1,314,012	$1,317,820	$1,138,628	$1,186,671	$1,085,056
Fixed Charges					
Interest on long-term debt	237,063	243,047	257,149	269,419	255,335
Other interest	16,814	17,704	47,239	23,947	24,063
Amortization of debt discount, premium and expense	16,340	13,300	8,497	5,243	4,998
Interest component of rentals	7,900	7,377	13,690	11,421	12,478
Fixed Charges	$ 278,117	$ 281,428	$ 326,575	$ 310,030	$ 296,874
Ratio of Earnings to Fixed Charges	4.72	4.68	3.49	3.83	3.65

DE00000532


CITIZENSHIP
DUKE POWER
SERVICE
WARNING
FOR ARCHIVES
Do Not Damage Or Destroy

DE00000533

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

[✓] **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
[Fee Required]

For the fiscal year ended December 31, 1994

[ ] **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
[No Fee Required]

For the transition period from _____ to _____

Commission file number 1-4928

DUKE POWER COMPANY

(Exact name of registrant as specified in its charter)

North Carolina	56-0205520
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
422 South Church Street, Charlotte, North Carolina	28242-0001
(Address of principal executive offices)	**(Zip Code)**

704-594-0887
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, without par value	New York Stock Exchange
Preferred Stock A, par value $25	
7.72%, 1992 Series	New York Stock Exchange
6.375% 1993 Series	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of Class

Preferred Stock, par value $100

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No _____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Estimated aggregate market value of the voting stock held by nonaffiliates of the registrant at March 27, 1995	$7,383,853,498
Number of shares of Common Stock, without par value, outstanding at March 27, 1995	204,859,339

Documents incorporated by reference:

The registrant is incorporating herein by reference certain sections of its proxy statement relating to the 1995 annual meeting of shareholders to provide information required by the following parts of this annual report:

Part III — Item 10., Directors and Executive Officers of the Registrant
— Item 11., Executive Compensation
— Item 12., Security Ownership of Certain Beneficial Owners and Management
— Item 13., Certain Relationships and Related Transactions

PETITIONER'S EXHIBIT

DUKE POWER COMPANY
FORM 10-K
ANNUAL REPORT TO
THE SECURITIES AND EXCHANGE COMMISSION
FOR THE YEAR ENDED DECEMBER 31, 1994

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DUKE POWER COMPANY

PART I.

Item 1. *Business.*

Duke Power Company (the Company) is primarily engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas. It is one of the nation's largest investor-owned electric utilities.

The Company is also engaged in a variety of diversified operations, most of which are organized in separate subsidiaries. During 1994, the Company reorganized, placing all its subsidiaries and diversified activities except for the core electric utility business into the Associated Enterprises Group (AEG). AEG includes Church Street Capital Corp.; Crescent Resources, Inc.; Duke Energy Group, Inc.; Duke Engineering & Services, Inc.; Duke/Fluor Daniel; Duke Merchandising; DukeNet Communications, Inc.; Duke Water Operations; and Nantahala Power and Light Company (NP&L). For additional information on subsidiaries and diversified activities, see "Subsidiaries and Diversified Activities" on page 9, "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — Subsidiaries and Diversified Activities" on page 22 and "Subsidiaries and Diversified Activities Highlights" on page 46.

During 1994, the Company's operating revenues, including AEG, were $4.5 billion. The Company's executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242-0001 (Telephone No. 704-594-0887).

Service Area

The Company's service area (excluding NP&L), approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 4.9 million and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville and Spartanburg in South Carolina. The Company supplies electric service directly to approximately 1.7 million residential, commercial and industrial customers in more than 200 cities, towns and unincorporated communities. Electricity is sold at wholesale to incorporated municipalities and to several public and private utilities. In addition, in 1994 approximately 8% of total sales were made through contractual agreements to former wholesale municipal or cooperative customers of the Company who had purchased portions of the Catawba Nuclear Station (collectively, the "Other Catawba Joint Owners") (See "Joint Ownership of Generating Facilities.") NP&L services an additional 53,000 mostly residential customers in five counties in western North Carolina.

The Company's service area is undergoing increasingly diversified industrial development. The textile, manufacture of machinery and equipment, and chemical and chemical related industries are of major significance to the economy of the area. Other industrial activity includes the rubber and plastic products, paper and allied products, and various other light and heavy manufacturing and service businesses. The largest industry served is the textile industry, which accounted for approximately $498 million of the Company's revenues for 1994, representing 12 percent of electric revenues and 40 percent of industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability at December 31, 1994, its sources of electric energy for 1994, and certain information presently projected for 1995:

Source	Generating Capability — KW(a)(b)(c)		Generation — KWH (millions)(c)
	Actual December 31, 1994	Projected December 31, 1995	Actual 1994
Coal	7,661,000	7,699,000(d)	32,714
Nuclear (e)	7,054,000	7,054,000	50,887
Hydro and other	3,266,000	4,154,000(f)	1,495
Total	17,981,000	18,907,000	85,096
Less: Other Catawba Joint Owners' share			15,300
Plus: Purchases from Other Catawba Joint Owners			9,046
Purchased power and net interchange			1,276
Total			80,118

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(a) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(b) Excludes firm purchases. (See "Energy Management and Future Power Needs.")

(c) Excludes NP&L.

(d) Includes the 38,000 KW fossil unit returned to service from the Plant Modernization Program on January 1, 1995.

(e) Nuclear capability and related generation for 1994 and projected for 1995 give no effect to the joint ownership of the Catawba Nuclear Station. (See "Joint Ownership of Generating Facilities.")

(f) Includes 12 units of the Lincoln Combustion Turbine Station with generating capacity of 888,000 KW scheduled to begin commercial operation in 1995. Four additional units with generating capacity of 296,000 KW are scheduled to begin commercial operation in 1996. (See "Capital Requirements.")

NP&L operates 11 hydroelectric stations with a total capacity of 100,000 kilowatts, and also buys supplemental power. The Company supplies supplemental power to NP&L under the terms of an interconnection agreement approved by the Federal Energy Regulatory Commission (FERC).

The Company has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power agreement.

According to 1993 industry statistics published in 1994, the Company ranked first in the nation in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Published rankings indicate that individual units at Marshall Steam Station and Belews Creek Steam Station ranked first, third, fifth, eighth and tenth most efficient in the nation in 1993. The Company's nuclear system continued its tradition of operating efficiency, operating at 82 percent of capacity for 1994, in comparison with the industry's most current average capacity factor of 71 percent for 1993.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The Company currently forecasts a 2.1 percent compound annual growth in peak load through 2009. An all-time peak load of 16,070,000 KW occurred on January 19, 1994 during extremely cold winter weather.

Rate Matters

The North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC) must approve the Company's rates for retail sales within their respective states. FERC must approve the Company's rates for sales to wholesale customers, including the contractual arrangements between the Company and the Other Catawba Joint Owners.

Rate requests filed by the Company in its most recent general rate case in 1991 with the NCUC, PSCSC and FERC were principally designed to reflect the Company's investment in the Bad Creek Hydroelectric Station. Rate orders issued by the NCUC and PSCSC in November 1991 recognized costs of the Bad Creek Hydroelectric Station, including an amortization of costs deferred between commercial operation and the rate order, which the Company had requested. The Company's wholesale customers challenged its proposed rate increase and in 1991 FERC issued an order that accepted the Company's proposed rates for filing. A negotiated settlement with these customers, which provided for an increase in wholesale rates consistent with the increase in retail rates, was approved by FERC and became effective in April 1992. (See Note 2, "Notes to Consolidated Financial Statements.")

In its most recent general rate case, the NCUC authorized a jurisdictional rate of return on common equity of 12.50 percent and the PSCSC authorized a jurisdictional rate of return on common equity of 12.25 percent.

In 1992, the North Carolina Supreme Court remanded to the NCUC the Company's 1986 rate order for the second time. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order in 1992 which resulted in a 1992 refund to North Carolina retail customers of approximately $95 million, including interest.

During 1992, NP&L filed an application for a general rate increase with the NCUC. A general rate increase was approved in June 1993.

Fuel and Purchased Power Cost Adjustment Procedures. Duke Power has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The NCUC ordered Duke Power to follow these procedures in its August 1986 order, which was effective for periods beginning January 1, 1986. The prospective adjustment in rates of past over- or under-recovery of fuel costs was challenged in the North Carolina courts. The North Carolina legislature ratified a bill in July 1987 assuring the legality of such adjustments in rates. In 1991, the statute was extended through June 30, 1997. In the North Carolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings. Fuel costs are reviewed semiannually in the wholesale and South Carolina retail jurisdictions.

All jurisdictions allow Duke Power to adjust rates for over- or under-recovery of fuel costs. Therefore, Duke Power reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

Construction Work in Progress (CWIP). The NCUC is permitted in its discretion to include CWIP in rate base after giving consideration to the public interest and the Company's financial stability. The PSCSC may include CWIP in rate base in its discretion.

Energy Management and Future Power Needs

The Company's strategy for meeting customers' present and future energy needs is composed of three components: demand-side resources, purchased power resources and supply-side resources. By utilizing these resources, the Company expects to maintain a reserve margin of approximately 17 to 23 percent of its anticipated peak load requirements through 1999.

Demand-side management programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The Company ultimately expects recovery through rates of associated deferred costs. The annual costs deferred, including the return, were approximately $25 million in 1994 and $26 million in 1993.

The Company continues to engage in a comprehensive energy management program as part of its Integrated Resource Plan. Integrated Resource Planning is the process used by utilities to evaluate a variety of resources. The goal is to provide adequate and reliable electricity in an environmentally responsible manner through cost-effective power management.

In January 1993, the PSCSC issued an order approving the Company's 1992 Integrated Resource Plan as reasonable, and approving a "shared savings" proposal for accomplishments made in the Company's demand-side management programs. In June 1993, the NCUC approved the 1992 plan, including the shared savings mechanism. The Integrated Resource Plan is filed every three years. Each of the other years, the Company files a Short Term Action Plan which updates the Integrated Resource Plan for any changes in projections for the next three years.

The purchase of capacity and energy is also an integral part of meeting future power needs. As of January 1, 1995, the Company has under contract 300 megawatts of capacity from other generators of electricity, including 62 megawatts from qualifying facilities. The Company expects to use a competitive bidding process to provide for the next increment of generating capacity beyond the Lincoln Combustion Turbine Station.

Capital Requirements

Projected capital expenditures, excluding costs related to portions of the Catawba Nuclear Station owned by the Other Catawba Joint Owners, for each of 1995, 1996, 1997, 1998 and 1999 and for the five-year period 1995-1999, as now scheduled, are as follows (in millions of dollars):

	1995	1996	1997	1998	1999	Total
Duke Power — Electric						
Generation	$332	$205	$261	$228	$322	$1,348
Transmission	42	44	45	47	48	226
Distribution	202	210	218	221	223	1,074
Other	93	77	67	72	73	382
Nuclear Fuel	104	103	158	123	132	620
Total	$773	$639	$749	$691	$798	$3,650
Associated Enterprises Group	$166	$137	$112	$101	$145	$ 661
Total Company	$939	$776	$861	$792	$943	$4,311

The Company's procedures for estimating capital expenditures (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs, allowances for inflation and the Company's business plan, which includes the expansion of the business activities of AEG. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

The Company is building a combustion turbine facility in Lincoln County, North Carolina to provide capacity at periods of peak demand. The Lincoln Combustion Turbine Station will consist of 16 combustion turbines with a total generating capacity of 1,184 megawatts. The estimated total cost of the project is approximately $500 million. Current plans are for 12 units to begin commercial operation by the end of 1995 and the remaining four to begin commercial operation in 1996. During 1991, the NCUC granted the Certificate of Public Convenience and Necessity and the North Carolina Division of Environmental Management issued a final air permit for the facility. The issuance of the final air permit for the facility was appealed, and one of the two appeals was settled and dismissed in March 1995. The other appeal has not been pursued by the appellant and is expected to be dismissed during the second quarter of 1995.

Joint Ownership of Generating Facilities

In order to reduce its need for external financing, the Company, through several transactions beginning in 1978, sold an 87½ percent undivided interest in the Catawba Nuclear Station to the Other Catawba Joint Owners.

These transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use (whether or not the facility is generating electricity) that portion of the capacity not then contractually required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The transactions also include a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station of the Company, which provides for an exchange of 50 percent of each Other Catawba Joint Owner's retained capacity from its ownership interest in the Catawba units for like amounts of capability and output from units of the McGuire Nuclear Station. The implementation of the reliability exchange has not had nor does the Company anticipate that such implementation will have a material effect on earnings. (See Note 3, "Notes to Consolidated Financial Statements.")

The Other Catawba Joint Owners and the Company were involved in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the Other Catawba Joint Owners which have been previously approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3, "Notes to Consolidated Financial Statements.") The Company and the Other Catawba Joint Owners entered into settlement agreements in 1994 which resolved all issues in contention in the proceedings. The Company has settled its cumulative net obligation through 1993 of approximately $205 million with the Other Catawba Joint Owners. Billings for 1994 and later years will conform to the settlement agreements,

which have been approved by the Company's retail regulatory commissions. Because it expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, the Company has included approximately $205 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Fuel Supply

The Company presently relies principally on nuclear fuel and coal for the generation of electric energy. The Company's reliance on oil and gas is minimal and will remain minimal even with the addition of the Lincoln Combustion Turbine Station.

Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

	Generation by Source Year Ended December 31			Cost of Fuel per Net KWH Generated (Cents) Year Ended December 31		
	1994	1993	1992	1994	1993	1992
Coal	38.5%	40.6%	36.7%	1.54	1.61	1.65
Nuclear	59.8	57.5	61.0	.56	.54	.54
Oil and Gas	—	—	—	—	—	—
All Fuels (cost based on weighted average)	98.3	98.1	97.7	.95	.99	.96
Hydroelectric(1)	1.7	1.9	2.3			
	100.0%	100.0%	100.0%			

(1) Generating figures are net of that output required to replenish pumped storage units during off-peak periods. Does not include NP&L.

Coal. The Company obtains a large amount of its coal under long-term supply contracts with mining operators utilizing both underground and surface mining. The Company has on hand an adequate supply of coal.

The Company's long-term supply contracts, all of which have price adjustment provisions, have expiration dates ranging from 1995 to 2003. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers for quantities and qualities of coal required. However, due to the Clean Air Act Amendments of 1990, fuel premiums may be required as contracts are renewed. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. The Company's short-term requirements have been and will be fulfilled with spot market purchases. The average sulfur content of coal being purchased by the Company is approximately 1 percent. Such coal satisfies the current emission limitation for sulfur dioxide for existing facilities. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — The Clean Air Act Amendments of 1990.")

Nuclear. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations. Based upon current projections, these contracts will meet the Company's requirements through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1997	1998	2000	2006
McGuire	1997	1998	2000	2009
Catawba	1997	1998	2000	2009

Uranium material requirements will be met through various supplier contracts, with uranium material produced primarily in the U.S., Canada and Australia. The Company believes that it will be able to renew contracts as they expire or to enter into similar contractual arrangements with other nuclear fuel materials and services suppliers. Short-term requirements have been and will be fulfilled with uranium spot market purchases.

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The Nuclear Waste Policy Act of 1982 requires that the Department of Energy (DOE) begin disposing of spent fuel no later than January 31, 1998. The Company has entered into the required contracts with the DOE for the disposal of nuclear fuel and began making payments in July 1983 for disposal costs of fuel currently being utilized. These payments, combined with a one-time payment for disposal costs of fuel consumed prior to April 7, 1983, have totaled about $563 million through 1994. In November 1989, the DOE released a report which indicated that it expects that a facility for spent fuel disposal will not be available until the year 2010. The DOE continues to pursue a centralized interim storage facility, with a target operation date of 1998, for earlier acceptance of spent fuel from utilities. The Company believes that it will be able to provide adequate on-system storage capacity until such time as the DOE begins receiving spent fuel.

Regulation

The Company is subject to the jurisdiction of the NCUC and the PSCSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of FERC, the Environmental Protection Agency (EPA) and state environmental agencies and to the jurisdiction of the Nuclear Regulatory Commission (NRC) as to design, construction and operation of its nuclear power facilities. The Company is exempt from regulation as a holding company under the Public Utility Holding Company Act of 1935, except with respect to the acquisition of the securities of other public utilities.

Environmental Matters. The Company is subject to federal, state, and local regulations with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. North Carolina has enacted a declaration of environmental policy requiring all state agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. South Carolina law also requires consideration by the PSCSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed major utility facilities, which include certain generation and transmission facilities. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. In 1994, the Company's construction costs for environmental protection totaled approximately $22 million, while the on-going environmental operation costs were approximately $25 million. The Company's 1995-1999 construction program includes costs for environmental protection which are estimated to be approximately $50 million, including $18.1 million in 1995, $8.5 million in 1996, $6.6 million in 1997, $8.6 million in 1998 and $8.5 million in 1999. These costs include expenditures associated with the Clean Air Act Amendments of 1990. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. These projections are subject to periodic review and revisions. Actual construction costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including cost and availability of capital.

AIR QUALITY. See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — The Clean Air Act Amendments of 1990" for a discussion of the Company's plans for compliance with federal clean air standards.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1987 (otherwise known as the "Clean Water Act") require permits for facilities that discharge into waters, to ensure compliance with its provisions. The Company holds numerous such permits and such permits are reissued periodically. The Clean Water Act was scheduled for reauthorization by Congress in 1994. Congress did not act to reauthorize the Clean Water Act in 1994, but it is likely that action will be taken on such reauthorization in 1995. Until Congress acts upon the reauthorization, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

OTHER ENVIRONMENTAL REGULATIONS. Contingencies associated with environmental matters are principally related to possible obligations to remove or mitigate the effects on the environment resulting from the disposal of certain substances at contamination sites.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as "Superfund", requires any individual or entity which may have owned or operated a contaminated site, as well as transporters or generators of hazardous wastes which were sent to such site, to assume joint and several responsibility for remediation of the site. Such parties are known as "potentially responsible parties" (PRPs). The Company is currently participating in PRP groups with regard to Superfund sites in Concord, North Carolina, and two sites in Pennsylvania. The Company is a PRP at a contamination site in Charlotte, North Carolina which is being remediated in accordance with a state act similar to CERCLA.

The Company is also a PRP at a site in Lenoir, North Carolina which will likely be remediated in accordance with federal or state law. In addition, the Company has agreed to remediate a small volume of PCB-contaminated soil at a site in Chester, South Carolina. While the total cost of remediation at these federal and state contamination sites may be substantial, the Company shares probable liability with other PRPs, many of which have substantial assets. Other contamination sites arise from the Company's operation of manufactured gas plant (MGP) sites until the early 1950's, some of which are still owned by the Company and some of which are now owned by third parties. In North Carolina, the Company is participating in a state-sponsored program to investigate and, where appropriate, remediate MGP sites. The State of South Carolina has expressed interest in entering into a similar arrangement. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

CERCLA was scheduled for reauthorization by Congress in 1994. An administration bill to reform CERCLA was acted upon by several Senate and House committees, but was never voted upon by either body. While CERCLA reform is likely to be acted upon by Congress in 1995, until such action occurs, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

GENERAL. Over the past few decades, the issue of the possible health effects of electric and magnetic fields has generated a number of generally inconclusive studies, some public concern and litigation as well as legislative action in some states regarding high voltage transmission lines. The impact of this issue on the Company cannot presently be determined.

Nuclear Facilities. The Company's nuclear facilities are subject to continuing regulation by the NRC.

Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company is planning for the replacement of steam generators at three units that have experienced SCC and has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. The current schedule for completion of the effort is as follows: Catawba Unit 1 — 1996, McGuire Unit 1 — 1997 and McGuire Unit 2 — 1997. The order of replacement is subject to change based on operational and project circumstances. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $170 million per unit, excluding the cost of replacement power and the reimbursement of applicable costs by the Other Catawba Joint Owners for Catawba Unit 1. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the Other Catawba Joint Owners, began a legal action on March 22, 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba Stations steam generators that were defective in design, workmanship and materials, requiring replacement well short of their stated design life. On March 17, 1994, the Company together with the Other Catawba Joint Owners, settled the lawsuit. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the results of operations or financial position of the Company.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The Other Catawba Joint Owners are responsible for decommissioning costs related to their ownership interest in the station. Both the NCUC and the PSCSC have granted the Company recovery of the estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume that units will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021, McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The NRC issued a rulemaking in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1994, the Company expensed approximately $52.5 million which was contributed to the external funds and accrued an additional $4.8 million to the internal reserve. The balance of the external funds as of December 31, 1994, was $172.4 million. The balance of the internal reserve as of December 31, 1994, was $204.8 million and is reflected

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in Accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid approximately $18 million during 1994 and $26.3 million cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of approximately $102 million in the Consolidated Balance Sheets at December 31, 1994.

Nuclear Insurance. For a discussion of the Company's nuclear insurance coverage, see "Note 13, Notes to Consolidated Financial Statements, Commitments and Contingencies — Nuclear Insurance."

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of 804,940 KW, are licensed for a term expiring in 2008. The Company also holds a license for the Keowee-Toxaway Project for a term expiring in 2016, covering the Keowee Hydro Station and the Jocassee Pumped Storage Station for a combined total of 769,500 KW, on the upper tributaries of the Savannah River in northwestern South Carolina. Additionally, the Company is the licensee through 2027 for the Bad Creek Hydroelectric Station which uses Lake Jocassee as its lower reservoir and has a nameplate rating of 1,065,000 KW. NP&L holds licenses for 11 hydroelectric projects with a nameplate rating of 100,000 KW with license terms expiring 2001-2006. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

The Company has major interconnections and arrangements with its neighboring utilities which it currently considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

Competition

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems, rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSCSC, respectively, of all areas outside municipalities in such states to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSCSC. In addition, the Company is engaged in continuing competition with various natural gas providers.

The Energy Policy Act of 1992 (EPACT) is moving utilities toward a more competitive environment. The EPACT reformed certain provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain regulatory barriers. For example, the EPACT allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. The EPACT requires transmission of power for third parties to wholesale customers on issuance of an order by the FERC, provided the reliability of service to the utility's local customer base is protected and the local customer base does not subsidize the third-party service. The EPACT does not permit the FERC to issue an order requiring transmission access to retail customers.

The electric utility industry currently is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based price of electricity, profits could be reduced and utilities might be

required to reduce their recorded asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation could also require some utilities to write off their regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are regionally and nationally competitive. The Company filed an open access transmission tariff with the FERC in early 1995 (See "Subsequent Events").

Subsidiaries and Diversified Activities

The Company continues to pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Although these opportunities are concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. (See "Subsidiaries and Diversified Activities Highlights" on page 46.)

Crescent Resources, Inc. (Crescent) pursues both residential and commercial real estate development, in addition to providing forest management activities focused on growing trees suitable for use in the construction, furniture and paper industries. At December 31, 1994, Crescent owned approximately 2,223,000 square feet of office, retail and warehouse space and had approximately 818,000 square feet of commercial properties under construction. Additionally, Crescent had approximately 266,000 acres of land under its management at year end.

Duke Energy Group, Inc. (Duke Energy) develops, owns and operates electric power-related facilities in the United States and abroad. Domestically, Duke Energy concentrates on advanced fossil-fueled generation including pulverized coal, circulating fluidized bed, coal gasification and natural gas technologies. Internationally, Duke Energy pursues advanced coal-fueled, hydroelectric and gas-fueled generation as well as transmission projects. Duke Energy has equity interests in two U.S. electric generation facilities and four international projects.

In 1994, Duke Energy announced plans to participate in power marketing activities in North America with Louis Dreyfus Electric Power (LDEP), following regulatory approvals. LDEP is currently the largest power marketer in the United States. (See "Subsequent Events.")

Nantahala Power and Light Company (NP&L) is a franchised electric utility which operates 11 hydroelectric plants with a total capacity of 100,000 kilowatts. NP&L has approximately 53,000 customers in western North Carolina. NP&L sold 907 million KWH in 1994 compared to 889 million KWH in 1993, excluding sales to Duke Power.

Other Business Units include Church Street Capital Corp., which is engaged in investment management for its subsidiaries; Duke Engineering & Services, Inc., which markets engineering, construction, quality assurance, consulting and other engineering-related services for facilities other than coal-fired generating plants, both nationally and internationally; Duke/Flour Daniel, a joint venture with Fluor Daniel, Inc., which provides engineering, construction, and support of operating and maintenance activities, primarily for coal-fired generating plants, both nationally and internationally; Duke Merchandising, which sells and services quality electric merchandise and electronics; DukeNet Communications, Inc. (DukeNet), which was formed in 1994 to develop and manage communications systems (See "Subsequent Events"); and Duke Water Operations, which provides franchised water services for Anderson, South Carolina and Rutherfordton, North Carolina.

Employees

At December 31, 1994, the Company had 17,052 full-time employees, which included 1,011 full-time employees of subsidiaries and diversified activities. About 2,000 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW). During the last quarter of 1994, the Company reached new labor agreements with the IBEW for one year terms.

The Company has been engaged in a concentrated effort to more efficiently and effectively utilize its resources through better work practices. During 1994, the Company offered a voluntary separation program which gave most employees the option of leaving the Company for a lump-sum payment and severance pay based on years of service. This voluntary separation program resulted in the departure of approximately 1,300 employees in 1994. Implementing programs such as the voluntary separation program and other efficiency practices has resulted in continued work-force reduction and in streamlined work flows. The number of full-time employees has decreased to the present level from 19,945 at year-end 1990.

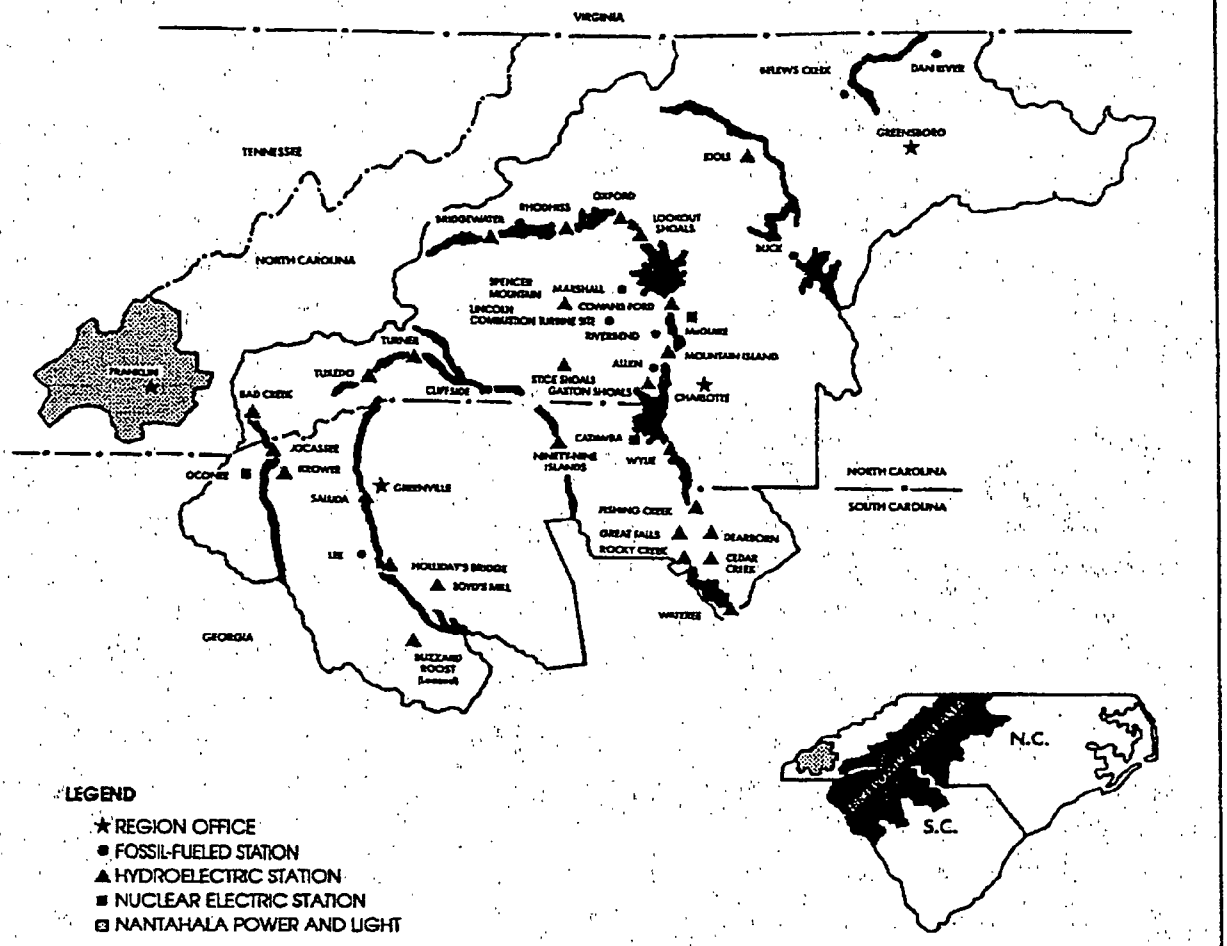
Subsequent Events

DukeNet entered into an agreement on December 8, 1994, as part of a consortium which includes BellSouth Personal Communications, Inc. and other companies, to bid for a personal communication services (PCS) license auctioned by the Federal Communications Commission (FCC). On March 13, 1995 the consortium won the bid and has agreed to pay for the license and, in compliance with FCC requirements, construct a substantial portion of the communication system. DukeNet has a 19.98% equity commitment to the consortium. Projected DukeNet capital commitments through 1999 are included in the Company's projected capital expenditures (See "Capital Requirements" on page 4).

On March 17, 1995, the Company filed for permission to sell wholesale electricity at market-driven prices with FERC. To date, the Company has sold wholesale power based on its bundled transmission, generation and distribution costs with an allowed return. The Company believes that this filing will strategically position the Company to become involved in the developing wholesale power market. The filing also included an open-access wholesale transmission tariff. This tariff sets the rates, terms and conditions under which the Company will transmit or wheel electricity from a third party through its system to a wholesale customer. Open access will provide the Company with increased opportunities to sell and deliver energy and capacity at market-based prices, thereby improving the utilization of existing assets. In addition, such access will provide an opportunity to buy energy and capacity at attractive rates, serving to further enhance the Company's competitive price position. In addition, Duke Energy Marketing Corp. (DEMC), an affiliate of Duke Energy, filed a request for power marketer status with FERC. Louis Dreyfus Electric Power and DEMC, in a joint venture, also filed an application with FERC for power marketer status. A power marketer buys blocks of electricity for immediate or eventual resale. Conditional approval is expected from FERC within six to eight months after filing. Final FERC approval for the filings is not expected for at least one year.

Recent liquidity problems in Argentina have caused a significant increase in Argentine interest rates and a severe limitation on local funds. Until such liquidity problems are resolved, Duke Energy is arranging financing alternatives which include additional equity infusions in its Argentine projects. Such infusions would not be material to the Company.

Duke Power Service Area



DUKE POWER COMPANY

OPERATING STATISTICS

	Year ended December 31				
	1994	1993	1992	1991	1990
Sources of Electric Energy (d)					
Millions of kilowatt-hours:					
Generated — net output:					
Coal	32,714	34,097	28,999	26,455	27,262
Nuclear (a)	50,887	48,211	48,238	49,328	44,649
Hydro (b)	1,460	1,582	1,834	1,545	1,879
Oil and gas	35	43	5	7	53
Total generation	85,096	83,933	79,076	77,335	73,843
Purchased power and net interchange (c)	1,276	1,750	1,403	587	1,531
Total output	86,372	85,683	80,479	77,922	75,374
Less: Other Catawba Joint Owners' share	15,300	13,821	14,313	12,280	11,735
Plus: Purchases from Other Catawba Joint Owners	9,046	8,810	9,466	8,525	8,658
Total sources of energy	80,118	80,672	75,632	74,167	72,297
Line loss and company usage	(4,555)	(4,614)	(4,590)	(4,280)	(4,222)
Total kilowatt-hour sales	75,563	76,058	71,042	69,887	68,075
Average Cost Per Ton of Coal Burned	$ 40.68	$ 42.21	$ 43.47	$ 45.21	$ 45.49
Electric Energy Sales (d)					
Millions of kilowatt-hours:					
Residential	18,870	19,465	17,789	17,918	17,221
General service	17,289	16,904	15,818	15,586	15,032
Industrial					
Textile	12,285	11,954	11,685	11,315	11,130
Other	17,005	16,244	15,356	14,955	14,764
Other energy and wholesale (c)(e)	10,274	11,337	10,360	10,132	10,468
Total kilowatt-hour sales billed	75,723	75,904	71,008	69,906	68,615
Unbilled kilowatt-hour sales	(160)	154	34	(19)	(540)
Total kilowatt-hour sales	75,563	76,058	71,042	69,887	68,075
Electric Revenue (d)					
Thousands of Dollars:					
Residential	1,379,740	1,424,173	1,312,227	1,272,322	1,216,945
General service	1,031,061	1,014,124	964,853	921,337	886,480
Industrial					
Textile	498,190	487,576	482,172	475,191	476,493
Other	745,154	726,399	696,413	668,765	654,551
Other energy and wholesale (c)(e)	540,256	476,862	460,849	441,777	391,803
Other electric revenue	84,928	152,742	44,970	37,568	78,859
Total electric revenues	$4,279,329	$4,281,876	$3,961,484	$3,816,960	$3,705,131
Number of Customers — End of Year (d)					
Residential	1,493,166	1,460,876	1,439,845	1,415,605	1,391,336
General service (f)	239,355	232,272	227,675	222,917	224,642
Industrial					
Textile	1,422	1,396	1,390	1,385	1,398
Other	7,320	7,338	7,314	7,255	7,325
Other energy and wholesale (c)	8,187	7,957	7,773	7,605	7,405
Total customers	1,749,450	1,709,839	1,683,997	1,654,767	1,632,106
Residential Customer Statistics (d)					
Average number for the year	1,483,497	1,455,609	1,431,403	1,409,775	1,383,799
Average annual use — KWH	12,720	13,372	12,427	12,710	12,444
Average annual billing	$ 930.06	$ 978.40	$ 916.74	$ 902.50	$ 879.42
Average Annual Billed Revenue Per KWH (d)					
Cents:					
Residential	7.31	7.32	7.38	7.10	7.07
General service	5.96	6.00	6.10	5.91	5.90
Industrial	4.24	4.31	4.36	4.35	4.37
Other energy and wholesale (c)(e)	5.26	4.21	4.45	4.36	3.74

(a) Includes 100% of Catawba generation.

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(b) 1991 includes KWH of the Bad Creek Hydroelectric Station prior to commercial operation.

(c) Kilowatt-hour sales, electric revenues, and Net interchange and purchased power for the year 1990 include a reclassification for certain power transactions previously classified as Net interchange and purchased power prior to a 1990 FERC order.

(d) Does not include operating statistics of NP&L.

(e) Includes sales to NP&L.

(f) 1991 restated to eliminate certain duplicate customers.

Executive Officers of the Company

WILLIAM H. GRIGG, 62, Chairman of the Board and Chief Executive Officer. Mr. Grigg served as Chairman of the Board, President and Chief Executive Officer, effective April 28, 1994, until July 27, 1994 when he assumed his present position. He served as Vice Chairman of the Board beginning in 1991, and Executive Vice President, Customer Group, beginning in 1988.

STEVE C. GRIFFITH, JR., 61, Vice Chairman of the Board and General Counsel. Mr. Griffith served as Executive Vice President and General Counsel from 1991 until he assumed his present position in July 1994. He served as Senior Vice President and General Counsel from 1982 until 1991.

RICHARD B. PRIORY, 48, President and Chief Operating Officer. Mr. Priory served as Executive Vice President, Power Generation Group, from 1991 until he assumed his present position in July 1994. He was Senior Vice President, Generation and Information Services, from 1988 to 1991.

WILLIAM A. COLEY, 51, President, Associated Enterprises Group. Mr. Coley was named Senior Vice President, Power Delivery, in 1988; Senior Vice President, Customer Group, in 1990; and Executive Vice President, Customer Group, in 1991. He was named to his present position in July 1994.

RICHARD J. OSBORNE, 43, Senior Vice President and Chief Financial Officer. Prior to assuming his current position in July 1994, Mr. Osborne served as Vice President and Chief Financial Officer beginning in 1991 and Vice President, Finance, from 1988 to 1991.

JEFFREY L. BOYER, 38, Controller. Mr. Boyer served as Director of Corporate Accounting for more than five years prior to assuming his present position in July 1994.

Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Item 2. *Properties.*

At December 31, 1994, the Company operated three nuclear generating stations, eight coal-fired stations and twenty-seven hydroelectric stations, all of which are located in North Carolina or South Carolina.

The following is a list of the major generating stations owned by the Company at December 31, 1994:

Facility	Energy Source	Net MW
Oconee	Nuclear	2,538
McGuire	Nuclear	2,258
Catawba (a)	Nuclear	2,258
Belews Creek	Coal	2,240
Marshall	Coal	2,090
Allen	Coal	1,140
Cliffside	Coal	760
Others	Coal	1,431
Bad Creek	Hydroelectric	1,065
Jocassee	Hydroelectric	610
Others	Hydroelectric	1,007
Combustion turbines	Oil and gas	584

(a) The Catawba Nuclear Station is a jointly-owned facility, of which the Company's ownership share is 12½ percent.

The Company is currently constructing the Lincoln Combustion Turbine Station, a 16-turbine facility designed to provide capacity at periods of peak demand. The station will have a total generating capacity of 1,184 megawatts. The facility is designed to operate on either natural gas or oil.

In addition to the electric generating plants described above, the Company owned, as of December 31, 1994, approximately 8,300 conductor miles of transmission lines and approximately 72,500 conductor miles of distribution lines. As of such date, the Company's transmission and distribution systems comprised approximately 1,700 substations with an installed transformer capacity of approximately 83,100,000 kVA.

NP&L's generation facilities consist of eleven hydroelectric plants with an aggregate nameplate capacity of approximately 100 MW. The transmission backbone of the system is a 161 kV line from Santeetlah to substations at Robbinsville, Nantahala Plant, Oak Grove, Webster and Thorpe Plant.

The map on page 11 shows the location of the Company's and NP&L's service area and generating stations.

Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see "Business — Energy Requirements and Capability" and "Capital Requirements".

Item 3. ***Legal Proceedings.***

Reference is made to "Business — Regulation", "Management Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — Commitment and Contingencies" and "Note 13, Notes to Consolidated Financial Statements, Commitments and Contingencies — Other".

Item 4. ***Submission of Matters to a Vote of Security Holders.***

No matters were submitted to a vote of the Company's security holders during the last quarter of 1994.

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PART II.

Item 5. ***Market for the Registrant's Common Equity and Related Stockholder Matters.***

The Common Stock of the Company is traded on the New York Stock Exchange. At December 31, 1994, there were approximately 129,637 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by the New York Stock Exchange Composite Transactions:

Common Stock	Dividends Per Share	Stock Price Range	
		High	Low
1994 By Quarter			
Fourth	$0.49	$42 1/8	$38
Third	0.49	39 7/8	35 1/2
Second	0.47	37	32 7/8
First	0.47	43	35 3/4
1993 By Quarter			
Fourth	$0.47	$44	$39
Third	0.47	44 7/8	39 7/8
Second	0.45	41 3/8	37 1/8
First	0.45	39 7/8	35 3/8

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Item 6.

SELECTED FINANCIAL DATA

	1994	1993	1992	1991	1990
Condensed consolidated statements of income (thousands)					
Operating revenues (a)	$ 4,488,913	$ 4,466,233	$ 4,122,503	$ 3,962,605	$ 3,862,395
Operating expenses (a)	3,309,087	3,258,422	3,087,422	2,968,239	2,949,387
Operating income	1,179,826	1,207,811	1,035,081	994,366	913,008
Interest expense and other income	(143,931)	(171,419)	(223,028)	(117,725)	(124,826)
Income before income taxes	1,035,895	1,036,392	812,053	876,641	788,182
Income taxes	397,019	409,977	303,970	293,018	249,994
Net income	638,876	626,415	508,083	583,623	538,188
Dividends on preferred and preference stock	49,724	52,429	56,407	54,683	52,616
Earnings for common stock	$ 589,152	$ 573,986	$ 451,676	$ 528,940	$ 485,572
Common stock data (b)					
Shares of common stock					
year-end (thousands)	204,859	204,859	204,859	204,699	202,584
average (thousands)	204,859	204,859	204,819	203,431	202,570
Per share of common stock					
Earnings	$ 2.88	$ 2.80	$ 2.21	$ 2.60	$ 2.40
Dividends	$ 1.92	$ 1.84	$ 1.76	$ 1.68	$ 1.60
Book value — year-end	$ 22.13	$ 21.17	$ 20.26	$ 19.86	$ 18.84
Market price — high-low	$ 43-32⅞	$ 44⅞-35⅜	$ 37½-31⅜	$ 35-26¾	$ 32⅛-25½
— year-end	$ 38⅛	$ 42⅜	$ 36⅛	$ 35	$ 30⅜
Balance sheet data (thousands)					
Total assets	$12,862,228	$12,293,605	$11,012,795	$10,617,552	$10,083,507
Long-term debt	$ 3,567,122	$ 3,285,397	$ 3,288,111	$ 3,235,492	$ 3,102,746
Preferred stock with sinking fund requirements	$ 279,500	$ 281,000	$ 279,519	$ 228,650	$ 239,800

(a) Operating revenues and operating expenses for the year 1990 include a reclassification for certain power transactions previously classified as Net interchange and purchased power prior to 1990 FERC order.

(b) All common stock data reflects the two-for-one split of common stock on September 28, 1990.

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Item 7. *Management's Discussion and Analysis of Results of Operations and Financial Condition*

Results of Operations

Earnings and Dividends. Earnings per share increased 3 percent from $2.80 in 1993 to $2.88 in 1994. The increase was primarily due to increased earnings of subsidiaries and diversified activities, increased allowance for funds used during construction and other deferred returns, and pre-funding of charitable contributions to the Duke Power Foundation in 1993. These items were offset by higher operating and maintenance expenses including recognition of certain non-recurring costs.

Excluding $.32 for the effect of a one-time refund to North Carolina retail customers in 1992, earnings per share increased from $2.53 in 1992 to $2.88 in 1994, indicating an average annual growth rate of 7 percent. Total Company earned return on average common equity was 13.3 percent in 1994 compared with 13.6 percent in 1993 and 12.8 percent in 1992, excluding the effects of the 1992 refund.

The Company continued its practice of annually increasing the common stock dividend. Common dividends per share increased at an average annual rate of 4 percent from $1.76 in 1992 to $1.92 in 1994. Indicated annual dividends per share increased to $1.96.

Revenues and Sales. Operating revenues increased at an average annual rate of 4 percent from 1992 to 1994, primarily because of increased overall kilowatt-hour sales to all retail customer classes. Revenues from subsidiaries and diversified activities contributed $49 million to the increase in Operating revenues over the three-year period, primarily from increased developed lot sales, land sales and equity earnings from investments in domestic and international joint ventures.

The Company does not expect the trend of annually increasing electric revenues to continue for 1995 and 1996 if normal weather conditions occur. Total electric revenues in 1995 and 1996 are expected to remain approximately the same as 1994 and increase thereafter. Revenues from retail customers are expected to increase because of continued growth in the service area. However, wholesale revenues are expected to decline as the other joint owners of the Catawba Nuclear Station retain a significantly larger portion of their ownership entitlement in 1995 and 1996, thereby reducing supplemental requirements supplied by the Company. The effect on earnings of such wholesale revenue decline will be partially offset by a decline in purchased power costs from the other joint owners which are not subject to levelization. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

Kilowatt-hour sales from Duke Power electric operations decreased 1 percent in 1994 compared with 1993. Sales to general service, textile and other-industrial customers increased by 2 percent, 3 percent and 5 percent, respectively, as a result of continued economic growth in Duke Power's service area. A new record peak demand of 16,070 megawatts was set in January 1994 for Duke Power's electric operations during a period of extremely cold temperatures. However, weather for most of the year was milder than normal and milder than 1993.

As a result, sales to residential customers decreased by 3 percent. Kilowatt-hour sales to the other joint owners of the Catawba Nuclear Station decreased 18 percent primarily because of improved output of the Catawba and McGuire Nuclear Stations from which they receive their energy entitlements.

Operating Expenses. From 1993 to 1994, Other operation and maintenance expenses rose 7 percent. Nuclear plant maintenance expenses increased primarily as a result of increased refueling outages, while fossil plant maintenance expenses increased primarily as a result of turbine and boiler outages. Administrative and general expenses increased primarily because of costs associated with a voluntary separation program offered during 1994 and non-recurring claims. (For additional information on the voluntary separation program, see Current Issues "Resource Optimization," page 20.)

Other operation and maintenance expenses increased at an average annual rate of 7 percent from 1992 to 1994. Administrative and general expenses increased over the period principally because of the voluntary separation program offered in 1994 and non-recurring claims. Fossil operating and maintenance expenses increased as a result of bringing refurbished units back on-line and increased boiler and turbine outages.

Fuel expense increased at an average annual rate of 3 percent from 1992 to 1994. The increase was due primarily to higher system production requirements satisfied by increased fossil generation. A continued decline of fuel prices over this period partially offset the overall increase in fuel expenses.

Net interchange and purchased power increased from $539 million in 1992 to $553 million in 1994, an average annual increase of 1 percent.

From 1992 to 1994, Depreciation and amortization expense decreased at an average annual rate of 4 percent primarily because the reduction in the amortization of property losses more than offset depreciation associated with additional investments. These investments are primarily associated with distribution plant including investment to support customer growth, and fossil plant resulting from bringing refurbished units back on-line.

Interest Expense and Other Income. Interest expense decreased at an average annual rate of 7 percent from 1992 to 1994. Interest on long-term debt decreased because of the Company's refinancing of higher-cost debt beginning in late 1991 and continuing throughout 1993. Interest expense also decreased as a result of the one-time impact in 1992 of approximately $27 million in interest paid to North Carolina retail customers because of a rate refund.

Allowance for funds used during construction (AFUDC) and other deferred returns, net of associated taxes, represented 13 percent of earnings for common stock in 1994 compared with 11 percent in 1992. AFUDC and other deferred returns are expected to be less than 14 percent of total earnings during the next three years.

AFUDC, net of associated taxes, represented 6 percent of earnings for common stock in 1994 compared with 5 percent in 1992. The increase was primarily the result of increased investment in the Lincoln Combustion Turbine Station. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs "Meeting Future Power Needs," page 20.)

The accrued return, net of associated taxes, on the purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station represented 7 percent of earnings for common stock in 1994 compared with 6 percent in 1993 and 1992. The growth in this return is due to the increasing cumulative impact of the Company's funding of purchased power costs, which the Company expects to collect through current rates in future periods. (For additional information on purchased capacity levelization, see Capital Needs "Purchased Capacity Levelization," page 19.)

Liquidity and Resources

Significant Rate Matters. During 1991, Duke Power filed in both the North Carolina and South Carolina retail jurisdictions its only requests for general rate increases since 1986. General rate increases approved in November 1991 resulted in additional annual revenues of $100.1 million and $30.2 million in North Carolina and South Carolina, respectively. The increases were needed primarily to recover costs associated with the commercial operation of the Bad Creek Hydroelectric Station.

In 1992, the North Carolina Supreme Court remanded to the North Carolina Utilities Commission (NCUC) Duke Power's 1986 rate order for the second time. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order in 1992 which resulted in a 1992 refund to North Carolina retail customers of approximately $95 million, including interest.

Duke Power has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all of Duke Power's regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

Catawba Settlements. The other joint owners of the Catawba Nuclear Station and the Company were involved in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which previously have been approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.) The Company and the other joint owners entered into settlement agreements in 1994 which resolved all issues in contention in the proceedings. The Company has settled its cumulative net obligation through 1993 of approximately $205 million with the other joint owners. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because it expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, the Company has included approximately $205 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Cash from Operations. Consolidated net cash provided by operating activities in 1994 accounted for 67 percent of total cash from operating, financing and investing activities compared with 46 percent in 1993 and 51 percent in 1992. Substantially all of the Company's capital needs were met by cash generated from operating activities for 1993 and 1992 when refinancing activities are excluded. Refinancing activities were insignificant in 1994.

Financing and Investing Activities. The Company's consolidated capital structure at year-end 1994, including subsidiary long-term debt, was 51 percent common equity, 40 percent long-term debt and 9 percent preferred stock. This structure is consistent with the Company's target to maintain a double-A credit rating. As of December 31, 1994, Duke Power's bonds were rated "AA" by Fitch Investors Service, "Aa2" by Moody's Investors Service, and "AA-" by Standard & Poor's Group and Duff & Phelps.

In response to favorable market conditions in 1992 and 1993, the Company refinanced $2.3 billion of long-term debt and $445 million of preferred stock. While there were no significant refinancings in 1994, the Company issued $407 million in debt, primarily First and Refunding Mortgage Bonds.

Duke Power's embedded cost of long-term debt, excluding debt of subsidiaries, was 7.98 percent for 1994 compared with 8.01 percent in 1993 and 8.39 percent in 1992. The embedded cost of preferred stock was 6.99 percent in 1994 compared with 6.76 percent in 1993 and 7.05 percent in 1992. The decreases are primarily the result of the Company's refinancing activities. The increase in the embedded cost of preferred stock from 1993 to 1994 reflects the impact of increasing dividend rates on variable rate preferred stocks.

Fixed Charges Coverage. Consolidated fixed charges coverage using the SEC method increased to 4.72 times for 1994 compared with 4.68 and 3.49 times in 1993 and 1992, respectively. Coverage increased primarily because of lower interest as a result of refinancing activities. Consolidated fixed charges coverage, excluding AFUDC and other deferred returns, was 4.32 for 1994 compared with 4.39 in 1993 and 3.27 in 1992 and the Company goal of 3.5 times. Coverage was somewhat lower in 1994 than 1993 as a result of a decrease in earnings excluding AFUDC and other deferred returns and higher in 1994 than 1992 because of higher earnings and lower interest expense.

Capital Needs

Property Additions and Retirements. Additions to property and nuclear fuel of $883 million and retirements of $238 million resulted in an increase in gross plant of $645 million in 1994.

Since January 1, 1992, additions to property and nuclear fuel of $2.2 billion and retirements of $839 million have resulted in an increase in gross plant of $1.4 billion.

Construction Expenditures. Plant construction costs for generating facilities supporting Duke Power electric operations, including AFUDC, increased from $145 million in 1992 to $309 million in 1994, primarily because of construction of the Lincoln Combustion Turbine Station. (For more information, see Capital Needs "Meeting Future Power Needs," page 20.) Construction costs for distribution plant, including AFUDC, decreased from $224 million in 1992 to $203 million in 1994.

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including AFUDC, are $3.0 billion and $620 million, respectively, for 1995 through 1999. Total projected construction costs include expenditures for the construction of the Lincoln Combustion Turbine Station and the replacement of certain steam generators at the McGuire and Catawba Nuclear Stations. (For additional information on steam generator replacement, see Current Issues "Stress Corrosion Cracking," page 21.) Projected capital expenditures of subsidiaries and diversified activities are $661 million for 1995 through 1999. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital. For 1995 through 1999, the Company anticipates funding its projected construction expenditures through the internal generation of funds and, to a lesser extent, through the issuance of debt securities.

Purchased Capacity Levelization. The rates established in Duke Power's electric retail jurisdictions permit recovery of its investment in both units of the Catawba Nuclear Station and the costs associated with contractual purchases of capacity from the other Catawba joint owners. The contracts relating to the sales of portions of the station obligate the Company to purchase a declining amount of capacity from the other joint owners. In the North Carolina retail jurisdiction, regulatory treatment of these contracts provides revenue for recovery of the capital costs and the fixed operating and maintenance costs of purchased capacity on a levelized basis. In the South Carolina retail jurisdiction, revenues are provided for the recovery of

the capital costs of purchased capacity on a levelized basis, while current rates include recovery of fixed operating and maintenance expenses.

Such rate treatments require the Company to fund portions of the purchased capacity payments until these costs, including accrued returns, are recovered at a later date. The Company recovers the accumulated costs and returns when the sum of the declining purchased capacity payments and accrual of returns for the current period drop below the levelized revenues. In the North Carolina retail jurisdiction, and wholesale jurisdiction regulated by the Federal Energy Regulatory Commission (FERC), purchased capacity payments continue to exceed levelized revenues. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups.

Meeting Future Power Needs. The Company's strategy for meeting customers' present and future energy needs consists of three components: supply-side resources, demand-side resources and purchased power resources. To assist in determining the optimal combination of these three resources, the Company uses an integrated resource planning process. The goal is to provide adequate and reliable electricity in an environmentally responsible, cost-effective manner.

The Company is building a combustion turbine facility in Lincoln County, North Carolina. The Lincoln Combustion Turbine Station, designed to provide capacity at periods of peak demand, will consist of 16 combustion turbines with a total generating capacity of 1,184 megawatts. The estimated total cost of the project is approximately $500 million. Current plans are for 12 units to begin commercial operation by the end of 1995 and the remaining four to begin commercial operation in 1996.

Demand-side management programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the Public Service Commission of South Carolina (PSCSC) provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The Company ultimately expects recovery through rates of associated deferred costs. The annual costs deferred, including the return, were approximately $25 million in 1994 and $26 million in 1993.

As of January 1, 1995, the Company has under contract 300 megawatts of firm purchased capacity from other generators of electricity, including 62 megawatts from qualifying facilities. The purchase of capacity and energy is also an integral part of meeting future power needs. The Company expects to use a competitive bidding process to provide for the next increment of generating capacity beyond the Lincoln Combustion Turbine Station.

Current Issues

While the Company improved its financial performance in 1994 compared with 1993, the ability to maintain and improve its current level of earnings will depend on several factors. As the industry becomes increasingly competitive, the Company's ability to control costs will be an important factor in maintaining a pricing structure that is both attractive to customers and profitable to the Company. While retail wheeling is presently not allowed in any form in the Company's service territory, the Company is focusing on providing competitive cost-based prices to its industrial customers, as well as to wholesale customers who already have access to alternative sources of energy. Other significant factors impacting the Company's future earnings levels include continued economic growth in the Piedmont Carolinas, the success of the Company's subsidiaries and diversified activities, and the outcome of various legislative and regulatory actions.

Resource Optimization. The Company has been engaged in a concentrated effort to more efficiently and effectively use its resources through better work practices. During 1994, the Company offered a voluntary separation program which gave most employees the option of leaving the Company for a lump-sum payment and severance pay based on years of service. This voluntary separation program resulted in the departure of approximately 1,300 employees in 1994. Implementing programs such as the voluntary separation program and other efficiency practices has resulted in continued work-force reduction and in streamlined work flows. The number of full-time employees has decreased from 19,945 at year-end 1990 to 17,052 at year-end 1994.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the

Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Such estimates presume each unit will be decommissioned as soon as possible following the end of its license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021, McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The Nuclear Regulatory Commission (NRC) issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1994, the Company expensed approximately $52.5 million which was contributed to the external funds and accrued an additional $4.8 million to the internal reserve. The balance of the external funds as of December 31, 1994, was $172.4 million. The balance of the internal reserve as of December 31, 1994, was $204.8 million and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets.

Both the NCUC and the PSCSC have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

Environmental Issues. The Company is subject to federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal, and other environmental matters. The Company was an operator of manufactured gas plants until the early 1950s. The Company has entered into a cooperative effort with the state of North Carolina and other owners of certain former manufactured gas plant sites to investigate and, where necessary, remediate these contaminated sites. The state of South Carolina has expressed interest in entering into a similar arrangement. The Company is considered by regulators to be a potentially responsible party and may be subject to liability at three federal Superfund sites and three comparable state sites. While the cost of remediation of these sites may be substantial, the Company will share in any liability associated with remediation of contamination at such sites with other potentially responsible parties. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

The Clean Air Act Amendments of 1990. The Clean Air Act Amendments of 1990 require a two-phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national objective of clean air in the most cost-effective manner and has already reduced emissions through the use of low-sulfur coal in its fossil plants, efficient plant operations and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. The Company is currently developing a detailed compliance plan for Phase II requirements which must be filed with the Environmental Protection Agency (EPA) by 1996. A preliminary strategy, which allows for varying options, indicates one-time costs associated with bringing the Company into compliance with the Act could range from $260 million to $750 million, depending on the compliance options the Company selects. The final strategy is contingent upon developments in the emissions allowance market, future regulatory and legislative actions, and advances in clean air technology. Additional annual operating and maintenance expenses will be incurred as well. All options within the preliminary strategy provide for full compliance with Phase II requirements by the year 2000.

Stress Corrosion Cracking. Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company is planning for the replacement of steam generators at three units that have experienced SCC and has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. The current schedule for completion of the effort is as follows: Catawba Unit 1 — 1996, McGuire Unit 1 — 1997 and McGuire Unit 2 — 1997. The order of replacement is subject to change based on operational and project circumstances. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $170 million, excluding the cost of replacement power and the reimbursement of applicable costs by the other joint owners for Catawba Unit 1. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the other joint owners of the Catawba Nuclear Station, began a legal action on March 22, 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba stations steam generators that were defective in design, workmanship and materials, requiring replacement well short of their stated design life. On March 17, 1994, the Company, together with the other joint owners of the Catawba Station, settled the lawsuit. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the results of operation or financial position of the Company.

Competition. The Energy Policy Act of 1992 (EPACT) is moving utilities toward a more competitive environment. The EPACT reformed certain provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain regulatory barriers. For example, the EPACT allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. The EPACT requires transmission of power for third parties to wholesale customers on issuance of an order by the FERC, provided the reliability of service to the utility's local customer base is protected and the local customer base does not subsidize the third-party service. The EPACT does not permit the FERC to issue an order requiring transmission access to retail customers.

The electric utility industry currently is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry, for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced and utilities might be required to reduce their recorded asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation could also require some utilities to write off their regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are regionally and nationally competitive. The Company anticipates filing an open access transmission tariff with the FERC in early 1995. Open access would provide the Company with increased opportunities to sell and deliver energy and capacity at market-based prices, thereby improving the utilization of existing assets. In addition, such access would provide an opportunity to buy energy and capacity at attractive rates, serving to further enhance the Company's competitive price position.

Commitments and Contingencies. The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which may involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

Subsidiaries and Diversified Activities. The Company continues to aggressively pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Although these opportunities are concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks.

The Company's subsidiaries and diversified activities contributed $52 million to net income in 1994 compared with $22 million in 1993 and $25 million in 1992. Increased developed lot and land sales, the sale of commercial rental property and the operation of generation and transmission facilities outside Duke Power's regulated service area generated additional income in 1994. A one-time gain on the sale of an investment in the preferred stock of an independent power development company also contributed to diversified income. Earnings of subsidiaries and diversified activities also include income from passive financial investments, engineering services fees, water operations and merchandising.

Domestically, the Company is seeking opportunities to: provide communications, water and engineering consulting services; construct, operate and maintain generation and transmission facilities; own generation facilities outside Duke Power's regulated service area; develop real estate; sell and service appliances and electronics; and participate in power marketing activities. The Company had equity investments in joint ventures, which own assets within the United States, of $14 million and $17 million at December 31, 1994 and 1993, respectively. Non-electric property of the Company's subsidiaries and diversified activities was $286 million and $216 million at December 31, 1994 and 1993, respectively.

Internationally, the Company is seeking opportunities to construct, own, operate and maintain generation and transmission facilities and to provide engineering consulting services. The Company had equity investments in international joint ventures, which own generation and transmission facilities, of $94 million and $85 million at December 31, 1994 and 1993, respectively.

ITEM 8. *Financial Statements and Supplementary Data.*

DUKE POWER COMPANY

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DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Operating revenues (Notes 1, 2 and 11)	$4,488,913	$4,466,233	$4,122,503
Operating expenses			
Fuel used in electric generation (Note 1)	705,019	732,246	659,593
Net interchange and purchased power (Notes 2 and 3)	553,355	535,125	538,841
Other operation and maintenance	1,341,659	1,254,028	1,166,940
Depreciation and amortization (Note 1)	459,781	496,971	499,048
General taxes	249,273	240,052	223,000
Total operating expenses	3,309,087	3,258,422	3,087,422
Operating income	1,179,826	1,207,811	1,035,081
Interest expense and other income (Note 1)			
Interest expense	(270,217)	(274,051)	(312,885)
Allowance for funds used during construction and other deferred returns	111,872	82,600	70,172
Other, net	14,414	20,032	19,685
Total interest expense and other income	(143,931)	(171,419)	(223,028)
Income before income taxes	1,035,895	1,036,392	812,053
Income taxes (Notes 1 and 4)	397,019	409,977	303,970
Net income	638,876	626,415	508,083
Dividends on preferred and preference stock	49,724	52,429	56,407
Earnings for common stock	$ 589,152	$ 573,986	$ 451,676
Common stock data (Note 6)			
Average shares outstanding (thousands)	204,859	204,859	204,819
Earnings per share	$ 2.88	$ 2.80	$ 2.21
Dividends per share	$ 1.92	$ 1.84	$ 1.76

See Notes to Consolidated Financial Statements.

DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Balance — Beginning of year	$2,410,825	$2,223,718	$2,141,259
Add — Net income	638,876	626,415	508,083
Total	3,049,701	2,850,133	2,649,342
Deduct			
Dividends			
Common stock	393,370	376,937	360,475
Preferred and preference stock	49,724	52,429	56,407
Capital stock transactions, net	687	9,942	8,742
Total deductions	443,781	439,308	425,624
Balance — End of year	$2,605,920	$2,410,825	$2,223,718

See Notes to Consolidated Financial Statements.

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DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Cash flows from operating activities			
Net Income	$ 638,876	$ 626,415	$ 508,083
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash items			
Depreciation and amortization (Note 1)	647,515	664,355	668,497
Deferred income taxes and investment tax credit amortization (Note 4)	94,261	62,897	49,490
Allowance for equity funds used during construction	(27,411)	(17,221)	(15,476)
Purchased capacity levelization (Note 3)	(268,925)	(20,049)	(66,511)
Other, net	22,460	73,607	37,978
(Increase) Decrease in Accounts receivable	47,586	(37,131)	8,166
Inventory	(28,568)	24,904	(11,131)
Prepayments	(435)	(2,396)	(1,084)
Increase (Decrease) in Accounts payable	(52,506)	(28,184)	75,976
Taxes accrued (Notes 1 and 4)	(51,641)	25,797	1,758
Interest accrued and other liabilities (Notes 1, 9 and 13)	14,523	30,508	(22,731)
Total adjustments	396,859	777,087	724,932
Net cash provided by operating activities	1,035,735	1,403,502	1,233,015
Cash flows from investing activities			
Construction expenditures and other property additions	(772,452)	(599,759)	(504,667)
Investment in nuclear fuel	(108,711)	(111,731)	(122,565)
External funding for decommissioning (Note 14)	(52,524)	(52,524)	(61,246)
Pre-funded pension cost (Note 12)	(30,000)	(50,000)	—
Investment in joint ventures (Note 11)	(6,718)	(70,345)	(18,565)
Net change in investment securities (Note 1)	17,922	46,489	(81,588)
Net cash used in investing activities	(952,483)	(837,870)	(788,631)
Cash flows from financing activities			
Proceeds from the issuance of			
First and refunding mortgage bonds	343,824	1,395,682	926,650
Preferred stock	—	215,633	281,089
Pollution-control bonds	—	76,265	—
Short-term notes payable, net (Note 5)	86,300	(105,200)	28,300
Construction loans and other	57,032	13,280	23,435
Payments for the redemption of			
First and refunding mortgage bonds	(81,781)	(1,399,336)	(1,013,218)
Preferred stock	(1,500)	(224,295)	(246,414)
Pollution-control bonds	—	(79,310)	—
Construction loans and other	(18,885)	(12,454)	(13,939)
Dividends paid	(443,633)	(427,868)	(417,443)
Other	(20,991)	(6,752)	(6,183)
Net cash used in financing activities	(79,634)	(554,355)	(437,723)
Net increase in cash	3,618	11,277	6,661
Cash at beginning of year	33,812	22,535	15,874
Cash at end of year	$ 37,430	$ 33,812	$ 22,535

See Notes to Consolidated Financial Statements.

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DUKE POWER COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 1994	December 31, 1993
	Dollars in Thousands	
ASSETS		
Current assets		
Cash (Notes 5 and 10)	$ 37,430	$ 33,812
Short-term investments (Note 10)	132,692	120,632
Receivables (less allowance for losses: 1994 — $6,637; 1993 — $6,404) (Note 1)	552,865	553,509
Inventory — at average cost	319,385	282,909
Prepayments and other	15,722	15,286
Total current assets	1,058,094	1,006,148
Investments and other		
Investments in joint ventures (Note 11)	108,330	101,612
Other investments, at cost or less (Note 10)	83,226	113,208
Nuclear decommissioning trust funds (Notes 10 and 14)	172,390	118,456
Pre-funded pension cost (Note 12)	80,000	50,000
Total investments and other assets	443,946	383,276
Property, plant and equipment		
Electric plant in service (at original cost — Notes 1, 3, 9, 13 and 14)		
Production	6,747,397	6,549,807
Transmission	1,439,435	1,400,790
Distribution	3,965,393	3,786,389
Other	1,020,192	974,123
Electric plant in service	13,172,417	12,711,109
Less accumulated depreciation and amortization	4,810,004	4,501,481
Electric plant in service, net	8,362,413	8,209,628
Nuclear fuel	757,983	705,994
Less accumulated amortization	415,560	405,910
Nuclear fuel, net	342,423	300,084
Construction work in progress (including nuclear fuel in process: 1994 — $52,273; 1993 — $113,904)	558,730	496,833
Total electric plant, net	9,263,566	9,006,545
Other property — at cost (less accumulated depreciation: 1994 — $24,137; 1993 — $20,314)	302,383	236,634
Total property, plant and equipment, net	9,565,949	9,243,179
Deferred debits (Notes 1, 3, 4 and 13)		
Purchased capacity costs	932,324	768,099
Debt expense	186,306	197,963
Regulatory asset related to income taxes	489,292	486,440
Regulatory asset related to DOE assessment fee	102,467	116,731
Other	83,850	91,769
Total deferred debits	1,794,239	1,661,002
Total assets	$12,862,228	$12,293,605
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 343,688	$ 373,202
Notes payable (Notes 5 and 10)	107,100	20,800
Taxes accrued (Note 1)	29,999	82,500
Interest accrued	72,157	68,868
Current maturities of long-term debt and preferred stock (Notes 8 and 9)	93,759	91,898
Other (Note 13)	121,539	215,543
Total current liabilities	768,242	852,811
Long-term debt (Notes 9 and 10)	3,567,122	3,285,397
Accumulated deferred income taxes (Notes 1 and 4)	2,348,631	2,243,366
Deferred credits and other liabilities		
Investment tax credit (Notes 1 and 4)	272,594	283,964
DOE assessment fee (Note 1)	102,467	116,731
Nuclear decommissioning costs externally funded (Note 14)	172,390	118,456
Other	318,453	274,146
Total deferred credits and other liabilities	865,904	793,297
Preferred and preference stock with sinking fund requirements (Notes 8 and 10)	279,500	281,000
Preferred and preference stock without sinking fund requirements (Notes 7 and 10)	500,000	500,000
Commitments and contingencies (Note 13)		
Common stockholders' equity (Notes 6 and 7)		
Common stock, no par, 300,000,000 shares authorized; 204,859,539 shares outstanding for 1994 and 1993	1,926,909	1,926,909
Retained earnings	2,605,920	2,410,825
Total common stockholders' equity	4,532,829	4,337,734
Total liabilities and stockholders' equity	$12,862,228	$12,293,605

See Notes to Consolidated Financial Statements.

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NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Revenues

Electric revenues are recorded as service is rendered to customers. "Receivables" on the Consolidated Balance Sheets include $163,270,000 and $175,726,000 as of December 31, 1994 and 1993, respectively, for electric service that has been rendered but not yet billed to customers.

B. Additions to Electric Plant

The Company capitalizes all construction-related direct labor and materials as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of money (allowance for funds used during construction). The cost of renewals and betterments of units of property is capitalized.

The cost of repairs and replacements representing less than a unit of property is charged to electric expenses. The original cost of property retired, together with removal costs less salvage value, is charged to accumulated depreciation.

C. Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities. AFUDC, a non-cash item, is recognized as a cost of "Construction work in progress" (CWIP), with an offsetting credit to "Interest expense and other income." After construction is completed, the Company is permitted to recover these construction costs, including a fair return, through their inclusion in rate base and in the provision for depreciation.

The 1994 and 1993 AFUDC rates of 9.64 and 9.29 percent for Duke Power include a component for debt cost on a pre-tax basis. The 1992 rate of 8.07 percent includes a component for debt cost on a net of tax basis. The change in calculation from a net of income tax basis to a pre-tax basis is a result of the adoption of Statement of Financial Accounting Standards No. 109 (SFAS 109). (See Note 4.) Rates for all periods are compounded semiannually.

D. Other Deferred Returns

Other deferred returns represent the estimated financing costs associated with funding certain regulatory assets. These regulatory assets primarily arise from the Company's funding of purchased capacity cost above levels collected in rates. Other deferred returns are non-cash items. They are primarily recognized as an addition to "Purchased capacity costs" and as an offsetting credit to "Interest expense and other income."

E. Depreciation and Amortization of Electric Plant

Provisions for electric plant depreciation are recorded using the straight-line method. The year-end composite weighted-average depreciation rates were 3.46 percent for 1994, 3.47 percent for 1993 and 3.48 percent for 1992.

Amortization of nuclear fuel is included in "Fuel used in electric generation" in the Consolidated Statements of Income. The amortization is recorded using the units-of-production method.

Under provisions of the Nuclear Waste Policy Act of 1982, the Company has entered into contracts with the Department of Energy (DOE) for the disposal of spent nuclear fuel. Payments made to the DOE for disposal costs are based on nuclear output and are included in "Fuel used in electric generation" in the Consolidated Statements of Income.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid $18,008,000 during 1994 and has paid $26,346,000 cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of $102,467,000 in the Consolidated Balance Sheets at December 31, 1994.

F. Subsidiaries

The Company's consolidated financial statements reflect consolidation of all of its majority-owned subsidiaries. Intercompany transactions have been eliminated in consolidation.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

G. Income Taxes

The Company and its subsidiaries file a consolidated federal income tax return.

Deferred income taxes have been provided for temporary differences. Temporary differences occur when events and transactions recognized for financial reporting result in taxable or tax-deductible amounts in future periods. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

H. Unamortized Debt Premium, Discount and Expense

Expenses incurred in connection with the issuance of presently outstanding long-term debt issued for regulated operations, and premiums and discounts relating to such debt, are being amortized over the terms of the respective issues. Also, any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations used to finance regulated assets and operations are being amortized over the lives of the new issues of long-term debt.

I. Consolidated Statements of Cash Flows

For purposes of the Consolidated Statements of Cash Flows, the Company's short-term investments in highly liquid debt instruments, with an original maturity of three months or less, are included in cash flows from investing activities and thus are not considered cash equivalents.

Total income taxes paid were $372,416,000, $354,981,000 and $217,144,000 for the years ended December 31, 1994, 1993 and 1992, respectively.

Interest paid, net of amounts capitalized, was $236,696,000, $249,659,000 and $303,222,000 for the years ended December 31, 1994, 1993 and 1992, respectively.

NOTE 2. RATE MATTERS

Duke Power Company

The North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC) must approve rates for retail sales within their respective states. The Federal Energy Regulatory Commission (FERC) must approve Duke Power's rates for sales to wholesale customers. Sales to the other joint owners of the Catawba Nuclear Station, which represent a substantial majority of Duke Power's wholesale revenues, are set through contractual agreements. (See Note 3.)

During 1991, Duke Power filed in both the North Carolina and South Carolina retail jurisdictions its only requests for general rate increases since 1986. General rate increases approved in November 1991 resulted in additional annual revenues of $100.1 million and $30.2 million in North Carolina and South Carolina, respectively. The increases were primarily needed to recover costs associated with the construction of the Bad Creek Hydroelectric Station. Also in 1991, Duke Power filed a request for a wholesale rate increase with the FERC. A negotiated settlement between Duke Power and the wholesale customers was approved by the FERC in 1992 and resulted in an increase in annual revenues of $2.1 million.

In 1992, the North Carolina Supreme Court remanded to the NCUC Duke Power's 1986 rate order for the second time. In this ruling, the Court held that the record from the 1986 proceedings failed to support the rate of return on common equity authorized by the NCUC after the initial decision of the Court remanding the 1986 rate order. The NCUC issued a final order in 1992 which resulted in a 1992 refund to North Carolina retail customers of approximately $95 million, including interest.

Fuel costs are reviewed semiannually in the wholesale and South Carolina retail jurisdictions, with provisions for changing such costs in base rates. In the North Carolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings.

All jurisdictions allow Duke Power to adjust rates for past over- or under-recovery of fuel costs. Therefore, Duke Power reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

NOTE 2. RATE MATTERS — Continued

The North Carolina legislature ratified a bill in July 1987 assuring the legality of such adjustments in rates. In 1991, the statute was extended through June 30, 1997.

Duke Power has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

Nantahala Power and Light Company

During 1992, Nantahala Power and Light Company (NP&L) filed an application for a general rate increase with the NCUC. A general rate increase was approved in June 1993 which resulted in additional annual revenues of $4.3 million. Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES

The Company previously sold interests in both units of the Catawba Nuclear Station. The other owners of portions of the Catawba Nuclear Station and supplemental information regarding their ownership are as follows:

Owner	Ownership Interest in the Station
North Carolina Municipal Power Agency Number 1 (NCMPA)	37.5%
North Carolina Electric Membership Corporation (NCEMC)	28.125%
Piedmont Municipal Power Agency (PMPA)	12.5%
Saluda River Electric Cooperative, Inc. (Saluda River)	9.375%

Each owner has provided its own financing for its ownership interest in the station.

The Company retains a 12.5 percent ownership interest in the Catawba Nuclear Station. As of December 31, 1994, $492,429,000 of "Electric plant in service" and "Nuclear fuel" represents the Company's investment in Units 1 and 2. Accumulated depreciation and amortization of $165,568,000 associated with Catawba has been recorded as of year-end. The Company's share of operating costs of Catawba are included in the Consolidated Statements of Income.

In connection with the joint ownership, the Company has entered into contractual agreements with the other joint owners to purchase declining percentages of the generating capacity and energy from the plant. These purchased power agreements were effective beginning with the commercial operation of each unit. Unit 1 and Unit 2 began commercial operation in June 1985 and August 1986, respectively. The purchased power agreements were established for 15 years for NCMPA and PMPA and 10 years for NCEMC and Saluda River. While the purchased power agreements with NCMPA and PMPA extend for 15 years, a significant decrease in the percentage of capacity and energy the Company is obligated to purchase occurs in the 11th calendar year of operation for each unit. This significant decrease occurs in 1995 for Unit 1 and 1996 for Unit 2. Certain provisions in the agreements with NCEMC and Saluda River have moderated the rate of decrease in the percentage of capacity and energy that the Company is obligated to purchase until 1996 when the Company has no further obligation to purchase capacity and related energy.

The agreements also provide for supplemental power sales by the Company to the other joint owners. Such power sales are to satisfy capacity and energy needs of the other joint owners beyond the capacity and energy which they retain from Catawba or potentially acquire in the form of other resources. As the joint owners retain more capacity and energy from Catawba, or a third party, supplemental power sales are expected to decline.

NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES — Continued

The agreements with each of the other joint owners include provisions that the Company will provide generating reserves to backstand the other joint owners' retained capacity in the Catawba plant at the system average cost of installed capacity. Additionally, the agreements include certain reliability exchanges designed to manage outage-related risks by exchanging energy entitlements between the Catawba Nuclear Station and the McGuire Nuclear Station, impacting the Company as well as all the other joint owners.

Energy cost payments are based on variable operating costs and are a function of the generation output of Catawba. Capacity payments are based on the fixed costs of the plant and include the capital costs and fixed operating and maintenance costs. Actual purchased capacity costs for 1994 and projected obligations for 1995 through 1999 are as follows (dollars in thousands):

Year	Purchased Capacity Capital Cost	Purchased Capacity Fixed O&M	Total Purchased Capacity
1994 Actual	$381,419	$126,774	$508,193
1995 Projected	$207,046	$ 91,465	$298,511
1996 Projected	$ 37,376	$ 18,698	$ 56,074
1997 Projected	$ 29,576	$ 15,006	$ 44,582
1998 Projected	$ 21,160	$ 11,459	$ 32,619
1999 Projected	$ 12,693	$ 7,009	$ 19,702

Effective in its November 1991 rate order, the North Carolina Utilities Commission (NCUC) reaffirmed the Company's recovery, on a levelized basis, of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners. The Public Service Commission of South Carolina (PSCSC) in its November 1991 rate order reaffirmed the Company's recovery on a levelized basis of the capital costs of capacity purchased from the other joint owners. Levelization was reaffirmed through inclusion in rates approved in March 1992 by the Federal Energy Regulatory Commission (FERC). The portion of purchased capacity subject to levelization not currently recovered in rates is being deferred, and the Company is recording a return on the accumulated balance. The Company recovers the accumulated balance, including the return, when the sum of the declining purchased capacity payments and accrual of returns for the current period drop below the levelized revenues. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups. The Company recovers the costs of purchased energy and the non-levelized portion of purchased capacity on a current basis.

The current levelized revenues approved in the Company's last general rate proceedings are $211,423,000, $94,137,000 and $6,815,000 for North Carolina retail, South Carolina retail and other wholesale (FERC), respectively. Purchased power costs, subject to levelization, are deferred based on allocation factors of approximately 62 percent, 26 percent and 2 percent for North Carolina retail, South Carolina retail and other wholesale (FERC), respectively. The Company also recovers an allocated amount of purchased power costs in the pricing of supplemental sales made to the other joint owners on a current basis.

In the North Carolina retail and FERC wholesale jurisdictions, purchased capacity payments continue to exceed levelized revenues. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments.

For the years ended December 31, 1994, 1993 and 1992, the Company recorded purchased capacity and energy costs from the other joint owners of $604,505,000, $547,899,000 and $514,327,000, respectively. These amounts, after adjustments for the costs of capacity purchased not reflected in current rates, are included in "Net interchange and purchased power" in the Consolidated Statements of Income. As of December 31, 1994 and 1993, $932,324,000 and $768,099,000, respectively, associated with the cost of capacity purchased but not reflected in current rates have been accumulated in the Consolidated Balance Sheets as "Purchased capacity costs." The cumulative impact of settlement agreements reflected in 1994 resulted in additional purchased capacity costs. (See Note 13.)

NOTE 4. INCOME TAX EXPENSE

The Company implemented Statement of Financial Accounting Standards No. 109 (SFAS 109), "Accounting for Income Taxes," effective January 1, 1993. SFAS 109 requires a liability approach for financial accounting and reporting of income taxes. No prior periods were restated because of the implementation of SFAS 109.

Accumulated deferred income taxes consist primarily of the following temporary differences (dollars in thousands):

	December 31, 1994		December 31, 1993	
Excess tax over book depreciation at historical tax rates	$1,343,605		$1,289,205	
Regulatory liability related to adjusting deferred taxes to the current statutory tax rate	(120,422)*		(124,952)*	
Net excess tax over book depreciation		$1,223,183		$1,164,253
Regulatory asset related to restating to a pre-tax basis		609,714*		611,392*
Deferred Catawba purchased capacity costs		361,018		254,789
Book versus tax basis difference		89,058		110,594
Loss on bond redemptions		70,067		74,438
Other		(4,409)		27,900
Total deferred income taxes		$2,348,631		$2,243,366

* The net regulatory asset related to income taxes is $489,292,000 for 1994 and $486,440,000 for 1993.

Total deferred income tax liability was $2,873,373,000 as of December 31, 1994, and $2,745,431,000 as of December 31, 1993. Total deferred income tax asset was $524,742,000 as of December 31, 1994, and $502,065,000 as of December 31, 1993.

Income tax expense for the years ended December 31, 1994, 1993 and 1992 consisted of the following (dollars in thousands):

	1994	1993	1992
Current income taxes			
Federal	$249,968	$283,930	$209,121
State	52,790	63,150	45,359
Total current income taxes	302,758	347,080	254,480
Deferred taxes, net			
Federal	83,359	59,267	45,820
State	22,153	14,887	14,932
Total deferred taxes, net	105,512	74,154	60,752
Investment tax credit amortization	(11,251)	(11,257)	(11,262)
Total income tax expense	$397,019	$409,977	$303,970

NOTE 4. INCOME TAX EXPENSE — Continued

Income taxes differ from amounts computed by applying the statutory tax rate to pre-tax income for the years ended December 31, 1994, 1993 and 1992 as follows (dollars in thousands):

	1994	1993	1992
Income taxes on pre-tax income at the statutory federal rate of 35% — 1994 and 1993; 34% — 1992	$362,563	$362,737	$276,098
Increase (reduction) in tax resulting from:			
Allowance for funds used during construction (AFUDC)	(9,594)	(6,027)	(7,221)
Amortization of investment tax credit deferrals	(11,251)	(11,257)	(11,262)
AFUDC in book depreciation/amortization	19,027	25,694	25,114
Deferred income tax flowback at rates higher than statutory	(5,530)	(9,091)	(21,685)
State income taxes, net of federal income tax benefits	47,872	51,289	39,407
Other items, net	(6,068)	(3,368)	3,519
Total income tax expense (see above)	$397,019	$409,977	$303,970

NOTE 5. SHORT-TERM BORROWINGS AND COMPENSATING-BALANCE ARRANGEMENTS

At December 31, 1994, the Company had a three-year revolving credit facility of $355,000,000 with 15 commercial banks. At December 31, 1993, the Company had two three-year revolving credit facilities of $300,000,000 and $130,000,000, with 17 and 5 commercial banks, respectively. The Company had $130,000,000 in commercial paper outstanding throughout 1994 and 1993 backed by the unused portion of the above three-year revolving credit facilities. The $130,000,000 in commercial paper is included in long-term debt. In addition, the Company had $44,980,000 in annually renewable lines of credit at December 31, 1994 and 1993. All such facilities are on a fee or compensating-balance basis with the exception of $20,000,000 in annually renewable lines of credit. The amount of short-term debt outstanding from these credit facilities as of December 31, 1994 and 1993 was $10,100,000 and $2,800,000, respectively.

Additionally, as of December 31, 1994 and 1993, the Company had $40,000,000 in pollution-control bonds backed by an unused, two-year revolving credit facility of $40,000,000. This facility is on a fee basis and the bonds are included in long-term debt.

Cash balances maintained at the banks on deposit were $13,214,000 as of December 31, 1994, and $12,988,000 as of December 31, 1993. Cash balances and fees compensate banks for their services, even though the Company has no formal compensating-balance arrangements. To compensate certain banks for credit facilities, the Company maintained balances of $49,000 as of December 31, 1994 and 1993. The Company retains the right of withdrawal with respect to the funds used for compensating-balance arrangements.

A summary of short-term borrowings is as follows (dollars in thousands):

	Twelve Months Ended		
	December 31, 1994	December 31, 1993	December 31, 1992
Amount outstanding at end of period — average rate of 6.02% as of December 31, 1994, 3.55% as of December 31, 1993, and 3.57% as of December 31, 1992	$107,100	$ 20,800	$126,000
Maximum amount outstanding during the period	$143,400	$180,800	$239,950
Average amount outstanding during the period	$ 24,161	$ 35,366	$ 64,050
Weighted-average interest rate for the period — computed on a daily basis	4.58%	3.19%	4.14%

NOTE 6. COMMON STOCK AND RETAINED EARNINGS

Common Stock

The Company issued common stock to satisfy the conversion rights of preference stock through April 6, 1992. (See Note 7.)

As of December 31, 1994, a total of 7,004,659 shares was reserved for issuance to stock plans.

Retained Earnings

As of December 31, 1994, substantially all of the Company's retained earnings were unrestricted as to the declaration or payment of dividends.

NOTE 7. PREFERRED AND PREFERENCE STOCK WITHOUT SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1994 and 1993:

	Par Value	Shares
Preferred Stock	$100	12,500,000
Preferred Stock A	25	10,000,000
Preference Stock	100	1,500,000

On April 6, 1992, the Company redeemed all outstanding shares of the Cumulative Preference Stock, 6¾% Convertible Series AA at its par value of $100 per share.

In 1992, 19,060 shares of preference stock were converted into 159,386 shares of common stock.

Preferred and preference stock without sinking fund requirements as of December 31, 1994 and 1993, were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1994	1993
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
7.85% S	1992	600,000	60,000	60,000
7.00% W	1993	500,000	50,000	50,000
7.04% Y	1993	600,000	60,000	60,000
7.72% (Preferred Stock A)	1992	1,600,000	40,000	40,000
6.375% (Preferred Stock A)	1993	2,400,000	60,000	60,000
Adjustable Rate A	1986	500,000	50,000	50,000
Auction Series A	1990	750,000	75,000	75,000
Total			$500,000	$500,000

NOTE 8. PREFERRED AND PREFERENCE STOCK WITH SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1994 and 1993:

	Par Value	Shares
Preferred Stock	$100	12,500,000
Preferred Stock A	25	10,000,000
Preference Stock	100	1,500,000

NOTE 8. PREFERRED AND PREFERENCE STOCK WITH SINKING FUND REQUIREMENTS — Continued

Preferred and preference stock with sinking fund requirements as of December 31, 1994 and 1993, were as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1994	1993
5.95% B (Preferred Stock A)	1992	800,000	$ 20,000	$ 20,000
6.10% C (Preferred Stock A)	1992	800,000	20,000	20,000
6.20% D (Preferred Stock A)	1992	800,000	20,000	20,000
7.12% Q	1987	470,000	47,000	—
		485,000	—	48,500
7.50% R	1992	850,000	85,000	85,000
6.20% T	1992	130,000	13,000	13,000
6.30% U	1992	130,000	13,000	13,000
6.40% V	1992	130,000	13,000	13,000
6.75% X	1993	500,000	50,000	50,000
Less: Current sinking fund requirements				
7.12% Q			(1,500)	(1,500)
Total			$279,500	$281,000

The annual sinking fund requirements through 1999 are $1,500,000 in 1995, 1996 and 1997, $5,750,000 in 1998 and $25,750,000 in 1999. Some additional redemptions are permitted at the Company's option.

The call provisions for the outstanding preferred stock specify various redemption prices not exceeding 105 percent of par value, plus accumulated dividends to the redemption date.

NOTE 9. LONG-TERM DEBT

Long-term debt outstanding as of December 31, 1994 and 1993, was as follows (dollars in thousands):

Series	Year Due	1994	1993
First and Refunding Mortgage Bonds:			
6.06%-6.23%	1994	$ —	$ 81,700
6.47%-6.60%	1995	40,300	40,300
4½%	1995	40,000	40,000
6.59%	1996	3,000	3,000
5⅜%	1997	72,600	72,600
5⅜%	1997	100,000	100,000
5.17%	1998	50,000	50,000
7.5%	1999	100,000	100,000
6¼%	1999	65,000	65,000
5.76%	1999	5,000	5,000
5.78%	1999	25,000	25,000
5.79%	1999	30,000	30,000
8% B	1999	200,000	—
7%	2000	100,000	100,000
7% B	2000	100,000	100,000
5⅞%	2001	150,000	150,000
6⅝% B	2003	100,000	100,000
5⅞% C	2003	75,000	75,000
6.125%	2003	75,000	75,000
8%	2004	75,000	75,000
6¼% B	2004	100,000	100,000
7.37%-7.41%	2004	100,000	100,000
7%	2005	200,000	200,000
6⅞%	2008	125,000	125,000
9⅝%	2020	46,982	46,982
10⅛% B	2020	24,854	24,854
8¼%	2021	150,000	150,000
8⅜% B	2021	150,000	150,000
8⅜%	2022	100,000	100,000
7⅜%	2023	200,000	200,000
6⅞% B	2023	200,000	200,000
7⅞%	2024	150,000	—
6¾%	2025	150,000	150,000
8.95%	2027	15,769	15,851
7%	2033	150,000	150,000
Pollution-Control Bonds:			
7.70%	2012	20,000	20,000
7.75% B	2017	10,000	10,000
7.50%	2017	25,000	25,000
3.69%	2014	40,000	40,000
5.80%	2014	77,000	77,000
Subtotal		3,440,505	3,172,287
Other Long-Term Debt:			
Capitalized leases		26,039	47,029
Other long-term debt		130,000	130,000
Unamortized debt discount and premium, net		(62,918)	(61,128)
Current maturities of long-term debt		(81,926)	(89,156)
Subtotal (a)		3,451,700	3,199,032
Subsidiary Long-Term Debt:			
Crescent Resources, Inc. (b)		92,102	54,149
Nantahala Power and Light (c)		33,653	33,458
Current maturities of long-term debt		(10,333)	(1,242)
Subtotal		115,422	86,365
Total long-term debt		$3,567,122	$3,285,397

(a) Substantially all of Duke Power's electric plant was mortgaged as of December 31, 1994.

(b) Substantial amounts of Crescent Resources, Inc.'s real estate development projects, land and buildings are pledged as collateral.

(c) Nantahala Power and Light's loan agreements impose net worth restrictions and limitations on disposal of assets and payment of cash dividends.

As of December 31, 1994 and 1993, the Company had $40,000,000 in pollution-control revenue bonds backed by an unused, two-year revolving credit facility of $40,000,000. In addition, the Company had $130,000,000 in commercial paper outstanding throughout 1994 and 1993 backed by unused three-year revolving credit facilities. These facilities are on a fee basis. Both the $40,000,000 in pollution-control bonds and the $130,000,000 in commercial paper are included in long-term debt.

NOTE 9. LONG-TERM DEBT — Continued

As of December 31, 1994, Crescent Resources, Inc. had $68,142,000 in mortgage loans which mature through 1999 and $23,960,000 in mortgage loans maturing in 2000 or thereafter, most requiring monthly payments of principal. Interest rates are variable and at December 31, 1994 ranged from 4.50 percent to 7.22 percent. As of December 31, 1994, Nantahala Power and Light Company had $33,000,000 in senior notes maturing in 2011 and 2012. The two notes carry fixed interest rates of 9.21 percent and 7.45 percent and require monthly payments of principal beginning in 1997 and 1998, respectively.

The annual maturities of consolidated long-term debt, including capitalized lease principal payments through 1999, are $92,259,000 in 1995; $12,540,000 in 1996; $212,708,000 in 1997; $62,559,000 in 1998; and $438,490,000 in 1999.

NOTE 10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts of Cash, Short-term investments, Other investments, at cost or less, and Notes payable approximate fair value primarily because of the short maturities of these instruments. The majority of estimated fair value amounts were obtained from independent parties. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 1994 and 1993, are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

External funds have been established, as required by the Nuclear Regulatory Commission, as a mechanism to fund certain costs of nuclear decommissioning. (See Note 14.) Currently, these nuclear decommissioning trust funds are primarily invested in municipal and U.S. government bonds. "Nuclear decommissioning trust funds" are presented on the Consolidated Balance Sheets at amounts that approximate fair value.

The carrying amounts and estimated fair values of long-term debt and preferred stocks are as follows (dollars in thousands):

	December 31, 1994		December 31,1993	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$3,696,260	$3,392,000	$3,389,894	$3,460,000
Preferred stock	$ 781,000	$ 697,000	$ 782,500	$ 801,000

In order to obtain variable rate financing at an attractive cost, the Company has entered into an interest rate swap agreement associated with the issuance on November 29, 1994, of $200,000,000 aggregate principal amount of its First and Refunding Mortgage Bonds, 8% Series B due 1999. The five-year interest rate swap is tied to the London Interbank Offered Rate (LIBOR), which is reset quarterly, and initially was set at 5.95%. As a result of the interest rate swap contract, interest expense on the Consolidated Statements of Income is recognized at the weighted average rate for the year tied to the LIBOR rate.

The Company has also entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Japanese yen associated with various steam generator contracts. The Company records any gains or losses associated with the hedge as an adjustment to the capitalized cost of the steam generators.

NOTE 11. INVESTMENT IN JOINT VENTURES

Certain investments in joint ventures are accounted for by the equity method. The Company's ownership in domestic and international joint ventures is 50 percent or less. The Company's proportionate share of net income in joint ventures for the years ended December 31, 1994, 1993 and 1992 was $7,049,000, $2,601,000 and ($1,179,000), respectively. These amounts are reflected in Operating revenues on the Consolidated Statements of Income. A summary of assets and liabilities of joint ventures follows (dollars in thousands):

	December 31, 1994		December 31, 1993	
	Total	Company's Proportionate Share	Total	Company's Proportionate Share
Assets of joint ventures	$1,117,449	$272,836	$972,315	$241,460
Liabilities of joint ventures	$ 504,029	$164,506	$413,453	$139,848

Of the $504,029,000 and $413,453,000 of total liabilities outstanding at December 31, 1994 and 1993, respectively, $407,605,000 and $290,178,000 represent non-recourse debt at December 31, 1994 and 1993, respectively, for which the Company bears no responsibility beyond the loss of its investment in the event the joint venture defaults on the debt.

NOTE 12. RETIREMENT BENEFITS

A. Retirement Plan

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own retirement plans, have a non-contributory, defined benefit retirement plan covering substantially all their employees. The benefit is based upon an age-related formula which takes into account years of creditable service and the employee's average compensation based upon the highest compensation during a consecutive sixty-month period. The benefit is reduced by an adjustment which is based upon the employee's social security wages. Normal retirement age under the Plan is age 65; however, early retirement benefits are payable as early as age 55 with 10 years of creditable service or age 51 if the employee has at least 30 years of creditable service. The Company's policy is to fund pension costs as accrued. During 1994 and 1993, the Company made additional contributions of $30,000,000 and $50,000,000, respectively, to enhance the funded position of the plan.

Net periodic pension cost for the years ended December 31, 1994, 1993 and 1992, include the following components (dollars in thousands):

	1994	1993	1992
Service cost benefit earned during the year	$ 43,098	$ 39,514	$ 35,701
Interest cost on projected benefit obligation	96,521	93,347	85,613
Actual return on plan assets	(6,138)	(117,898)	(50,897)
Amount deferred for recognition	(86,995)	35,652	(32,277)
Expected return on plan assets	(93,133)	(82,246)	(83,174)
Net amortization	7,657	4,137	3,812
Net periodic pension cost	$ 54,143	$ 54,752	$ 41,952

NOTE 12. RETIREMENT BENEFITS — Continued

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1994 and 1993, is as follows (dollars in thousands):

	1994	1993
Accumulated benefit obligation:		
Vested benefits	$(1,070,355)	$(1,087,705)
Nonvested benefits	(4,420)	(3,946)
Accumulated benefit obligation	$(1,074,775)	$(1,091,651)
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$ 1,167,158	$ 1,137,992
Projected benefit obligation	(1,368,740)	(1,311,921)
Unrecognized net experience loss	319,519	265,566
Unrecognized prior service cost reduction	(38,872)	(42,705)
Remaining unrecognized transitional obligation	935	1,068
Pre-funded pension cost	$ 80,000	$ 50,000

In determining the projected benefit obligation, the weighted-average assumed discount rate used was 8.25 percent in 1994, 7.50 percent in 1993 and 8.25 percent in 1992. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 5.40 percent in 1994, 4.50 percent in 1993 and 5.40 percent in 1992. The expected long-term rate of return on plan assets used in determining pension cost was 9.00 percent in 1994, 8.40 percent in 1993 and 9.25 percent in 1992.

During 1993, the Company offered an enhanced early retirement option, Limited Period Separation Opportunity (LPSO), for eligible employees. The Company recorded an additional one-time expense for special termination benefits associated with LPSO of approximately $7,611,000.

B. Postretirement Benefits

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own postretirement benefit plans, currently provides certain health care and life insurance benefits for retired employees. Employees become eligible for these benefits if they retire at age 55 or greater with 10 years of service or if they retire as early as age 51 with 30 years or more of service. Employees retiring after January 1, 1992, receive a fixed Company allowance, based on years of service, to be used to pay medical insurance premiums. The Company reserves the right to terminate, suspend, withdraw, amend or modify the plans in whole or in part at any time.

In 1992, the Company commenced funding the maximum amount allowable under section 401(h) of the Internal Revenue Code, which provides for tax deductions for contributions and tax-free accumulation of investment income. Such amounts partially fund the Company's medical and dental postretirement benefits. The Company has also established a Retired Lives Reserve, which has tax attributes similar to 401(h) funding, to partially fund its postretirement life insurance obligation. The Company contributed $12,269,000 into these funding mechanisms in 1994 and $14,648,000 in 1993.

NOTE 12. RETIREMENT BENEFITS — Continued

Net periodic postretirement benefit cost for the years ended December 31, 1994, 1993 and 1992 include the following components (dollars in thousands):

	1994	1993	1992
Service cost benefit earned during the year	$ 5,415	$ 4,974	$ 4,644
Interest cost on accumulated postretirement benefit obligation	25,321	25,482	23,347
Actual return on plan assets	(1,451)	(4,143)	(2,953)
Amount deferred for recognition	(3,469)	334	1,061
Expected return on plan assets	(4,920)	(3,809)	(1,892)
Straight-line — 20 year amortization of transitional obligation	13,293	13,479	13,479
Other amortization	366	278	160
Net periodic postretirement benefit cost	$39,475	$40,404	$39,738

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1994 and 1993, is as follows (dollars in thousands):

	1994	1993
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$ 69,987	$ 57,840
Actives eligible to retire	(11,902)	(21,810)
Actives not eligible to retire	(90,499)	(90,621)
Retirees and surviving spouses	(239,978)	(238,522)
Accumulated postretirement benefit obligation	(342,379)	(350,953)
Unrecognized prior service cost	783	1,923
Unrecognized net experience (gain)/loss	14,448	29,127
Unrecognized transitional obligation	225,988	242,629
(Accrued) postretirement benefit cost	$ (31,173)	$ (19,434)

In determining the accumulated postretirement benefit obligation (APBO), the weighted-average assumed discount rate used was 8.25 percent in 1994, 7.50 percent in 1993 and 8.25 percent in 1992. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 5.40 percent in 1994, 4.50 percent in 1993 and 5.40 percent in 1992. The expected long-term rate of return on 401(h) assets used in determining postretirement benefits cost was 9.00 percent in 1994, 8.40 percent in 1993 and 9.25 percent in 1992. For Retired Lives Reserve assets, 6.50 percent was used in 1994 and 7.125 percent was used in 1993 and 1992.

The assumed medical inflation rate was approximately 12.50 percent in 1994. This rate decreases by 0.5 percent to 1.0 percent per year until a rate of 5.5 percent is achieved in the year 2002, which remains fixed thereafter.

A 1.0 percent increase in the medical and dental trend rates produces a 5.05 percent ($1,552,000) increase in the aggregate service and interest cost. The increase in the APBO attributable to a 1.0 percent increase in the medical and dental trend rates is 4.10 percent ($14,029,000) as of December 31, 1994.

NOTE 13. COMMITMENTS AND CONTINGENCIES

A. Construction Program

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including allowance for funds used during construction, are $3.0 billion and $620 million, respectively, for 1995 through 1999. Projected capital expenditures of subsidiaries and diversified activities are $661 million for 1995 through 1999. These projections are subject to

NOTE 13. COMMITMENTS AND CONTINGENCIES — Continued

periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

B. Nuclear Insurance

The Company maintains nuclear insurance coverage in three areas: liability coverage, property, decontamination and decommissioning coverage, and extended accidental outage coverage to cover increased generating costs and/or replacement power purchases. The Company is being reimbursed by the other joint owners of the Catawba Nuclear Station for certain expenses associated with nuclear insurance premiums paid by the Company.

Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $8.9 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $8.7 billion, which will be increased by $79.3 million as each additional commercial nuclear reactor is licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. The $8.7 billion could also be reduced by $79.3 million for certain nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs and public liability damages exceed primary insurances, licensees may be assessed up to $79.3 million for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $79.3 million amount is subject to indexing for inflation and may be subject to state premium taxes. This amount is further subject to a surcharge of 5 percent (which is included in the above $8.7 billion figure) if funds are insufficient to pay claims and associated costs. If retrospective premiums were to be assessed, the other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of such assessment.

The Company is a member of Nuclear Mutual Limited (NML), which provides $500 million in primary property damage coverage for each of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $36 million. This amount represents 5 times the Company's annual premium to NML. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NML policies applicable to Catawba.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. NEIL provides excess insurance coverage of $2.25 billion for the Catawba Nuclear Station and $1.5 billion for each of the Oconee and McGuire Nuclear Stations. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, the Company will be liable, on a pro rata basis, for additional assessments of up to $62 million. This amount is limited to 7.5 times the Company's annual premium to NEIL for excess property, decontamination and decommissioning liability insurance. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to Catawba. The Company has also purchased an additional $850 million of excess property damage insurance for its Catawba plant through a pool of stock and mutual insurance companies.

The Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Each unit of the Oconee, McGuire and Catawba Nuclear Stations is insured for up to approximately $3.5 million per week, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100 percent for 52 weeks and 80 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $30 million. This amount represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage

NOTE 13. COMMITMENTS AND CONTINGENCIES — Continued

of a nuclear unit. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to the joint ownership agreements.

C. Other

The other joint owners of the Catawba Nuclear Station and the Company were involved in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information, see Note 3.) The Company and the other joint owners entered into settlement agreements in 1994 which resolved all issues in contention in the proceedings. The Company has settled its cumulative net obligation through 1993 of approximately $205 million with the other joint owners. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because it expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, the Company has included approximately $205 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5 "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or financial position of the Company.

NOTE 14. NUCLEAR DECOMMISSIONING COSTS

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the North Carolina Utilities Commission and the Public Service Commission of South Carolina have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume each unit will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021, McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The Nuclear Regulatory Commission issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1994, the Company expensed approximately $52,524,000 which was contributed to the external funds and accrued an additional $4,841,000 to the internal reserve. Nuclear units are depreciated at a rate of 4.70 percent, of which 1.61 percent is for decommissioning. The balance of the external funds as of December 31, 1994, was $172,390,000. The balance of the internal reserve as of December 31, 1994, was $204,837,000 and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

NOTE 15. RECLASSIFICATION

In the Consolidated Statements of Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows, certain prior-year information has been reclassified to conform with 1994 classifications.

INDEPENDENT AUDITORS' REPORT

Duke Power Company:

We have audited the consolidated financial statements of Duke Power Company and subsidiaries (the Company) listed in the accompanying index on page 23. Our audits also included the consolidated financial statement schedule listed in the accompanying index on page 23. These financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1994 and 1993, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1994 in conformity with generally accepted accounting principles. Also, in our opinion, such consolidated financial statement schedule when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

Charlotte, North Carolina
February 10, 1995

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Power Company are prepared by management, which is responsible for their integrity and objectivity. The statements are prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions which should be included. The other information in the annual report is consistent with the financial statements. In preparing these statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed according to management's authorization. Internal accounting controls also provide reasonable assurance that transactions are recorded properly, so that financial statements can be prepared according to generally accepted accounting principles. In addition, the Company's accounting controls provide reasonable assurance that errors or irregularities which could be material to the financial statements are prevented or are detected by employees within a timely period as they perform their assigned functions. The Company's accounting controls are continually reviewed for effectiveness. In addition, written policies, standards and procedures, and a strong internal audit program augment the Company's accounting controls.

The Board of Directors pursues its oversight role for the financial statements through the Audit Committee, which is composed entirely of directors who are not employees of the Company. The Audit Committee meets with management and internal auditors periodically to review the work of each group and to monitor each group's discharge of its responsibilities. The Audit Committee also meets periodically with the Company's independent auditors, Deloitte & Touche LLP. The independent auditors have free access to the Audit Committee and the Board of Directors to discuss internal accounting control, auditing and financial reporting matters without the presence of management.

JEFFREY L. BOYER
Controller

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SELECTED QUARTERLY FINANCIAL DATA
(Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	Dollars in Thousands (except per-share data)				
1994 by quarter					
Operating revenues	$1,099,002	$1,083,310	$1,272,525	$1,034,076	$4,488,913
Operating income	$ 326,584	$ 242,419	$ 430,861	$ 179,962	$1,179,826
Net income	$ 173,617	$ 128,002	$ 243,741	$ 93,516	$ 638,876
Earnings per share	$ 0.79	$ 0.56	$ 1.13	$ 0.40	$ 2.88
1993 by quarter					
Operating revenues	$1,048,365	$1,034,371	$1,340,657	$1,042,840	$4,466,233
Operating income	$ 276,637	$ 246,748	$ 451,028	$ 233,398	$1,207,811
Net income	$ 141,684	$ 122,470	$ 241,409	$ 120,852	$ 626,415
Earnings per share	$ 0.63	$ 0.53	$ 1.12	$ 0.52	$ 2.80

Generally, quarterly earnings fluctuate with seasonal weather conditions and maintenance of electric generating units, especially nuclear units.

SUBSIDIARIES AND DIVERSIFIED ACTIVITIES HIGHLIGHTS

During 1994, the Company reorganized, placing all its subsidiaries and diversified activities into the Associated Enterprises Group (AEG). AEG includes the following:

- **Church Street Capital Corp.** (CSCC) manages investment funds and serves as the parent company for the non-electric operating subsidiaries. CSCC investment highlights are as follows (dollars in thousands):

  Short-term investments and marketable securities

1994	1993	1992
$170,642	$155,871	$173,347

  Investment income (after tax) (a)

1994	1993	1992
$7,562	$3,548	$5,404

- **Crescent Resources, Inc.** is engaged in real estate development and forest management.
- **Duke Energy Group, Inc.**, parent of Duke Energy Corp., structures, finances and manages investments in electric generation and transmission facilities, both nationally and internationally.
- **Duke Engineering & Services, Inc.** markets engineering, construction, quality assurance, consulting and other engineering-related services for facilities other than coal-fired generating plants, both nationally and internationally.
- **Duke/Fluor Daniel**, a joint venture with Fluor Daniel, Inc., provides engineering, construction, and support of operating and maintenance activities, primarily for coal-fired generating plants, both nationally and internationally.
- **Duke Merchandising** sells and services quality electric merchandise and electronics primarily to Duke Power customers.
- **DukeNet Communications, Inc.** develops and manages communication systems.
- **Duke Water Operations** serves areas of Anderson, South Carolina, and Rutherfordton, North Carolina.
- **Nantahala Power and Light Company** provides electric service to a five-county area in western North Carolina by its operation of eleven hydroelectric stations and purchase of supplemental power.

Operating Results

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Operating revenues			
Crescent Resources, Inc.	$ 64,724	$ 46,784	$ 44,788
Duke Energy Group, Inc. (b)	9,478	6,033	1,805
Nantahala Power and Light Company (c)	68,595	67,142	60,183
All Other Business Units (d)	109,932	106,340	92,613
Total Associated Enterprises Group	$252,729	$226,299	$199,389
Operating income			
Crescent Resources, Inc.	$ 46,236	$ 30,004	$ 30,602
Duke Energy Group, Inc.	(1,035)	(2,929)	(3,474)
Nantahala Power and Light Company	12,224	8,844	6,937
All Other Business Units (d)	15,506	1,939	8,743
Total Associated Enterprises Group	$ 72,931	$ 37,858	$ 42,808
Net income			
Crescent Resources, Inc.	$ 26,525	$ 16,327	$ 16,613
Duke Energy Group, Inc. (e)	5,749	(1,949)	(2,239)
Nantahala Power and Light Company	6,169	4,261	3,526
All Other Business Units (d)	13,593	2,876	7,458
Total Associated Enterprises Group	$ 52,036	$ 21,515	$ 25,358

Financial Position

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Total assets			
Crescent Resources, Inc.	$294,175	$219,206	$195,476
Duke Energy Group, Inc. (f)	110,656	144,499	25,876
Nantahala Power and Light Company	125,883	107,872	94,531
All Other Business Units (d)	279,430	265,977	314,783
Total Associated Enterprises Group	$810,144	$737,554	$630,666
Total liabilities			
Crescent Resources, Inc.	$134,574	$ 86,172	$ 84,526
Duke Energy Group, Inc.	4,672	31,816	3,108
Nantahala Power and Light Company	72,542	60,700	51,620
All Other Business Units (d)	22,312	30,902	29,495
Total Associated Enterprises Group	$234,100	$209,590	$168,749

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Cash Flows

	Year ended December 31,		
	1994	1993	1992
	Dollars in Thousands		
Cash provided by (used in) operating activities			
Crescent Resources, Inc.	$ 37,691	$ 36,254	$ 25,926
Duke Energy Group, Inc.	(6,614)	(1,438)	(1,936)
Nantahala Power and Light Company	12,817	14,869	7,039
All Other Business Units (d)	10,589	8,795	32,719
Total Associated Enterprises Group	$ 54,483	$ 58,480	$ 63,748
Cash provided by investing activities			
Crescent Resources, Inc.	$ 2,524	$ 1,310	$ 122
Duke Energy Group, Inc. (g)	40,740	28,785	—
Nantahala Power and Light Company	—	—	—
All Other Business Units (h)	5,100	21,377	3,168
Total Associated Enterprises Group	$ 48,364	$ 51,472	$ 3,290
Cash used in investing activities			
Crescent Resources, Inc.	$ 78,689	$ 43,444	$ 21,910
Duke Energy Group, Inc.	19,575	116,498	22,147
Nantahala Power and Light Company	23,989	19,254	12,746
All Other Business Units (i)	18,500	1,450	55,756
Total Associated Enterprises Group	$140,753	$180,646	$112,559
Cash provided by (used in) financing activities (j)			
Crescent Resources, Inc. (k)	$ 37,589	$ 945	$ (8,993)
Duke Energy Group, Inc. (l)	—	—	—
Nantahala Power and Light Company	10,896	3,206	7,184
All Other Business Units (m)	(6,993)	71,537	54,979
Total Associated Enterprises Group	$ 41,492	$ 75,688	$ 53,170

Other Information

	December 31,		
	1994	1993	1992
Full-time employees at year-end			
Crescent Resources, Inc.	89	77	73
Duke Energy Corp.	35	24	18
Nantahala Power and Light Company	184	194	191
All Other Business Units	703	755	777
Total Associated Enterprises Group	1,011	1,050	1,059

(a) Earnings for 1994, 1993 and 1992 exclude elimination of intercompany profits of $49,000, $509,000 and $1,211,000, respectively.

(b) Includes Duke Energy Group, Inc.'s allocable share of net income from joint ventures. (See "Note 11, Notes to Consolidated Financial Statements.")

(c) Nantahala Power and Light Company's Operating revenues include revenues from the sale of electricity to Duke Power of $12,131,000, $13,683,000 and $12,640,000 for 1994, 1993 and 1992, respectively.

(d) All Other Business Units amounts include Associated Enterprises Group intercompany eliminations.

(e) 1994 includes a gain of $4,800,000, after tax, from the sale of preferred stock.

(f) Includes Duke Energy Group, Inc.'s investments in joint ventures. (See "Note 11, Notes to Consolidated Financial Statements.")

(g) 1994 includes proceeds from the sale of preferred stock of $32,468,000 and debt securities of $3,360,000. 1993 includes proceeds from the sale of debt securities of $19,654,000.

(h) 1993 includes the net change in short-term investments for the period of $20,653,000.

(i) 1994 and 1992 include the net change in short-term investments for the period of $12,060,000 and $49,282,000, respectively.

(j) Excludes capital infusion and return of capital transactions between Church Street Capital Corp. and its subsidiaries.

(k) 1993 and 1992 exclude capital infusions from parent, Church Street Capital Corp., of $6,000,000 and $5,000,000, respectively.

(l) 1994 excludes net return of capital to parent, Church Street Capital Corp., of $12,100,000. 1993 and 1992 exclude net capital infusions from Church Street Capital Corp. of $91,864,000 and $24,360,000, respectively.

(m) 1993 and 1992 each include capital infusions from Duke Power to Church Street Capital Corp. of $75,000,000.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Description	Balance Beginning of Year	Balance End of Year
	Dollars in Thousands	
For the Year Ended December 31, 1994		
Reserves Related to Assets on Balance Sheet	$ 10,353	$ 8,059
Other Reserves		
Operating Reserves (1)	107,477	154,722
For the Year Ended December 31, 1993		
Reserves Related to Assets on Balance Sheet	10,730	10,353
Other Reserves		
Operating Reserves (1)	78,103	107,477
For the Year Ended December 31, 1992		
Reserves Related to Assets on Balance Sheet	25,592	10,730
Other Reserves		
Operating Reserves (1)	67,577	78,103

(1) Principally consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits and Other Liabilities" in the Consolidated Balance Sheets.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

No events necessary to be disclosed by the Company under this item have occurred.

PART III.

Item 10. ***Directors and Executive Officers of the Registrant.***

Information for this item concerning directors of the Company is set forth in the sections entitled "Election of Directors", "Information Regarding the Board of Directors" and "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1995 annual meeting of shareholders, which are being incorporated herein by reference.

Information concerning the executive officers of the Company is set forth in the section entitled "Executive Officers of the Company" in this annual report.

Item 11. ***Executive Compensation.***

Information for this item is set forth in the section entitled "Executive Compensation" in the proxy statement of the Company relating to its 1995 annual meeting of shareholders, which is being incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management.***

Information for this item is set forth in the section entitled "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1995 annual meeting of shareholders, which is being incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions.***

Information for this item is set forth in the sections entitled "Information Regarding the Board of Directors" and "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1995 annual meeting of shareholders, which are being incorporated herein by reference.

PART IV.

Item 14. *Exhibits, Consolidated Financial Statement Schedules, and Reports on Form 8-K.*

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Consolidated Financial Statements

Consolidated Statements of Income for the Three Years Ended December 31, 1994

Consolidated Statements of Retained Earnings for the Three Years Ended December 31, 1994

Consolidated Statements of Cash Flows for the Three Years Ended December 31, 1994

Consolidated Balance Sheets — December 31, 1994 and 1993

Notes to Consolidated Financial Statements

Selected Quarterly Financial Data (Unaudited)

Consolidated Financial Statement Schedule

Schedule II — Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 1994

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

(b) Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1994.

(c) Exhibits — See Exhibit Index on page 54.

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Charlotte and State of North Carolina on the 29th day of March, 1995.

DUKE POWER COMPANY
(Registrant)

By: W. H. GRIGG
Chairman of the Board and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
W. H. GRIGG	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	March 29, 1995
RICHARD J. OSBORNE	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 29, 1995
JEFFREY L. BOYER	Controller (Principal Accounting Officer)	March 29, 1995
G. ALEX BERNHARDT CRANDALL C. BOWLES W. A. COLEY STEVE C. GRIFFITH, JR. W. H. GRIGG PAUL H. HENSON JAMES V. JOHNSON GEORGE DEAN JOHNSON, JR. W. W. JOHNSON MAX LENNON JAMES G. MARTIN BUCK MICKEL R. B. PRIORY RUSSELL M. ROBINSON, II	A Majority of the Directors	March 29, 1995

ELLEN T. RUFF, by signing her name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

/s/ ELLEN T. RUFF
Ellen T. Ruff, Attorney-In-Fact

EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the Securities and Exchange Commission and pursuant to Rule 12b-32 are incorporated herein by reference.

Exhibit Number	
3-A	—Restated Articles of Incorporation of registrant, dated as of October 6, 1993 (filed with Form S-3, File No. 33-50617, effective October 20, 1993, as Exhibit 4(A)).
3-B	—Articles of Amendment of registrant dated November 1, 1993, relating to the 6.375% Cumulative Preferred Stock A, 1993 Series (filed with Form S-3, No. 33-52479, effective March 29, 1994, as Exhibit 4(B)).
3-C	—By-Laws of registrant, as amended (filed with Form S-3, No. 33-50584, effective August 11, 1992, as Exhibit 3(g)).
4-B-1	—First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated as of December 1, 1927 (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(a)).
4-B-2	—Supplemental Indenture, dated as of March 12, 1930, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).
4-B-3	—Supplemental Indenture, dated as of July 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(c)).
4-B-4	—Supplemental Indenture, dated as of December 1, 1935, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(d)).
4-B-5	—Supplemental Indenture, dated as of September 1, 1936, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).
4-B-6	—Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).
4-B-7	—Supplemental Indenture, dated as of April 1, 1944 supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).
4-B-8	—Supplemental Indenture, dated as of September 1, 1947 supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).
4-B-9	—Supplemental Indenture, dated as of September 8, 1947 supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).
4-B-10	—Supplemental Indenture, dated as of February 1, 1949 supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).
4-B-11	—Supplemental Indenture, dated as of March 1, 1949 supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).
4-B-12	—Supplemental Indenture, dated as of April 1, 1951 supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(l)).
4-B-13	—Supplemental Indenture, dated as of September 1, 1953 supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-13).
4-B-14	—Supplemental Indenture, dated as of October 1, 1954 supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).
4-B-15	—Supplemental Indenture, dated as of January 1, 1955 supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-15).
4-B-16	—Supplemental Indenture, dated as of May 1, 1956 supplementing said Mortgage (filed with Form S-9, File No. 2-12402 effective April 26, 1956, as Exhibit 2-B-16).
4-B-17	—Supplemental Indenture, dated as of January 1, 1960 supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).
4-B-18	—Supplemental Indenture, dated as of February 1, 1960 supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).
4-B-19	—Supplemental Indenture, dated as of February 1, 1962 supplementing said Mortgage (filed with Form S-9, File No. 2-20577, effective August 16, 1962, as Exhibit 2-B-20).
4-B-20	—Supplemental Indenture, dated as of August 1, 1962 supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-19).
4-B-21	—Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 3, 1966, as Exhibit 4-B-20).

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Exhibit Number	
4-B-22	—Supplemental Indenture, dated as of February 1, 1965, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 23, 1966, as Exhibit 4-B-21).
4-B-23	—Supplemental Indenture, dated as of April 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-28023, effective February 15, 1968, as Exhibit 2-B-25).
4-B-24	—Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No. 2-31304, effective January 21, 1969, as Exhibit 2-B-26).
4-B-25	—Supplemental Indenture, dated as of February 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-34289, effective August 27, 1969, as Exhibit 2-B-27).
4-B-26	—Supplemental Indenture, dated as of September 1, 1969, supplementing said Mortgage (filed with Form S-7, File No. 2-36095, effective February 16, 1970, as Exhibit 2-B-39).
4-B-27	—Supplemental Indenture, dated as of March 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-37953, effective July 28, 1970, as Exhibit 2-B-42).
4-B-28	—Supplemental Indenture, dated as of August 1, 1970, supplementing said Mortgage (filed with Form S-7, File No. 2-39451, effective March 4, 1971, as Exhibit 2-B-28).
4-B-29	—Supplemental Indenture, dated as of March 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-42404, effective December 7, 1971, as Exhibit 2-B-29).
4-B-30	—Supplemental Indenture, dated as of December 1, 1971, supplementing said Mortgage (filed with Form S-7, File No. 2-43122, effective March 7, 1972, as Exhibit 2-B-30).
4-B-31	—Supplemental Indenture, dated as of April 1, 1972, supplementing said Mortgage (filed with Form S-7 File No. 2-46208, effective November 20, 1972, as Exhibit 2-B-31).
4-B-32	—Supplemental Indenture, dated as of December 1, 1972, supplementing said Mortgage (filed with Form S-7, File No. 2-48058, effective June 5, 1973, as Exhibit 2-B-32).
4-B-33	—Supplemental Indenture, dated as of June 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-49333, effective November 5, 1973, as Exhibit 2-B-33).
4-B-34	—Supplemental Indenture, dated as of November 1, 1973, supplementing said Mortgage (filed with Form S-7, File No. 2-50493, effective April 25, 1974, as Exhibit 2-B-34).
4-B-35	—Supplemental Indenture, dated as of May 1, 1974, supplementing said Mortgage (filed with Form S-7, File No. 2-52669, effective February 11, 1975, as Exhibit 2-B-35).
4-B-36	—Supplemental Indenture, dated as of February 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-36).
4-B-37	—Supplemental Indenture, dated as of July 1, 1975, supplementing said Mortgage (filed with Form S-7, File No. 2-57118, effective October 5, 1976, as Exhibit 2-B-37).
4-B-38	—Supplemental Indenture, dated as of October 1, 1976, supplementing said Mortgage (filed with Form S-7, File No. 2-59494, effective August 10, 1977, as Exhibit 2-B-38).
4-B-39	—Supplemental Indenture, dated as of September 1, 1977, supplementing said Mortgage (filed with Form S-7, File No. 2-61995, effective July 26, 1978, as Exhibit 2-B-39).
4-B-40	—Supplemental Indenture, dated as of August 1, 1978, supplementing said Mortgage (filed with Form S-7, File No. 2-64541, effective June 7, 1979, as Exhibit 2-B-40).
4-B-41	—Supplemental Indenture, dated as of June 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-65371, effective October 2, 1979, as Exhibit 2-B-41).
4-B-42	—Supplemental Indenture, dated as of October 1, 1979, supplementing said Mortgage (filed with Form S-7, File No. 2-66659, effective March 12, 1980, as Exhibit 2-B-42).
4-B-43	—Supplemental Indenture, dated as of March 1, 1980, supplementing said Mortgage (filed with Form S-16, File No.2-68571, effective August 19, 1980, as Exhibit 2-B-43).
4-B-44	—Supplemental Indenture, dated as of August 1, 1980, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-44).
4-B-45	—Supplemental Indenture, dated as of March 1, 1982, supplementing said Mortgage (filed with Form S-16, File No. 2-75951, effective February 23, 1982, as Exhibit 2-B-45).
4-B-46	—Supplemental Indenture, dated as of September 1, 1982, supplementing said Mortgage (filed with Form S-3, File No. 2-78882, effective August 30, 1982, as Exhibit 4-B-46).
4-B-47	—Supplemental Indenture, dated as of May 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-47).
4-B-48	—Supplemental Indenture, dated as of September 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-48).
4-B-49	—Supplemental Indenture, dated as of September 1, 1984, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-49).
4-B-50	—Supplemental Indenture, dated as of March 1, 1985, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-50).

Exhibit Number	
4-B-51	—Supplemental Indenture, dated as of December 1, 1985, supplementing said Mortgage (filed with Form S-3, File No. 33-5163, effective May 2, 1986, as Exhibit 4-B-51).
4-B-52	—Supplemental Indenture, dated as of April 1, 1986, supplementing said Mortgage (filed with Form S-3, File No. 33-5163, effective May 2, 1986, as Exhibit 4-B-52).
4-B-53	—Supplemental Indenture, dated as of May 1, 1986, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-53).
4-B-54	—Supplemental Indenture, dated as of June 1, 1986, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-54).
4-B-55	—Supplemental Indenture, dated as of February 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-55).
4-B-56	—Supplemental Indenture, dated as of February 15, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-56).
4-B-57	—Supplemental Indenture, dated as of March 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-57).
4-B-58	—Supplemental Indenture, dated as of October 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1987, File No. 1-4928, as Exhibit 4-B-58).
4-B-59	—Supplemental Indenture, dated as of February 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1989, File No. 1-4928, as Exhibit 4-B-59).
4-B-60	—Supplemental Indenture, dated as of March 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-60).
4-B-61	—Supplemental Indenture, dated as of May 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-61).
4-B-62	—Supplemental Indenture, dated as of May 15, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-62).
4-B-63	—Supplemental Indenture, dated as of March 1, 1991, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-63).
4-B-64	—Supplemental Indenture, dated as of July 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-64).
4-B-65	—Supplemental Indenture, dated as of December 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-65).
4-B-66	—Supplemental Indenture, dated as of March 1, 1992, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1991, File No. 1-4928, as Exhibit 4-B-66).
4-B-67	—Supplemental Indenture, dated as of June 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-67).
4-B-68	—Supplemental Indenture, dated as of July 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-68).
4-B-69	—Supplemental Indenture, dated as of September 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-53308, effective November 24, 1992, as Exhibit 4-B-69).
4-B-70	—Supplemental Indenture, dated as of February 1, 1993, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, as Exhibit 4-B-70).
4-B-71	—Supplemental Indenture, dated as of March 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-59448, effective March 17, 1993, as Exhibit 4-B-71).
4-B-72	—Supplemental Indenture, dated as of April 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-72).
4-B-73	—Supplemental Indenture, dated as of May 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-73).
4-B-74	—Supplemental Indenture, dated as of June 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-74).
4-B-75	—Supplemental Indenture, dated as of July 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-75).
4-B-76	—Supplemental Indenture, dated as of August 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-76).
4-B-77	—Supplemental Indenture, dated as of August 20, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-77).
*4-B-78	—Supplemental Indenture, dated as of May 1, 1994, supplementing said Mortgage.
*4-B-79	—Supplemental Indenture, dated as of November 1, 1994, supplementing said Mortgage.

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Exhibit Number	
*4-C	—Instrument of Resignation, Appointment and Acceptance among Duke Power Company, Morgan Guaranty Trust Company of New York, as Trustee, and Chemical Bank, as Successor Trustee, dated as of August 30, 1994.
10-A	—Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).
10-B	—Agreement, dated August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).
10-C	—Agreement, dated October 14, 1980 between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-D	—Agreement, dated October 14, 1980 between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-E†	—Employees' Stock Ownership Plan.
10-F††	—Employee Incentive Plan.
10-G††	—1993 Executive Long-Term Incentive Plan.
10-H†	—Supplemental Security Plan.
10-I†	—Stock Purchase-Savings Program for Employees.
10-J†	—Employees' Retirement Plan.
10-K†	—Supplemental Retirement Plan.
10-L†	—Compensation Deferral Plan.
10-M†	—Compensation Deferral Plan for Outside Directors.
10-N†	—Retirement Plan for Outside Directors.
10-O†	—Supplementary Defined Contribution Plan for Employees.
10-P†	—Directors' Charitable Giving Program.
10-Q†	—Vacation Banking Plan.
10-R†	—Estate Conservation Plan.
10-S†	—Supplemental Insurance Plan.
10-T†	—Group Life Insurance Plan.
10-U†	—Stock Ownership Plan for Nonemployee Directors.
*10-V	—Executive Short-Term Incentive Plan.
*10-W	—Executive Long-Term Incentive Plan.
*12	—Computation of Ratio of Earnings to Fixed Charges.
*23	—Consent of Independent Auditors.
*24(a)	—Power of attorney authorizing Ellen T. Ruff and others to sign the annual report on behalf of the registrant and certain of its directors and officers.
*24(b)	—Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.
*27	—Financial Data Schedule.

† Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, under the same exhibit number as listed herein.

†† Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1993, File No. 1-4928, under the same exhibit number as listed herein.

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EXHIBIT 12

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in Thousands)

	Year Ended December 31				
	1994	1993	1992	1991	1990
Earnings Before Income Tax	$1,035,895	$1,036,392	$ 812,053	$ 876,641	$ 788,182
Fixed Charges	278,117	281,428	326,575	310,030	296,874
Total	$1,314,012	$1,317,820	$1,138,628	$1,186,671	$1,085,056
Fixed Charges					
Interest on long-term debt	237,063	243,047	257,149	269,419	255,335
Other interest	16,814	17,704	47,239	23,947	24,063
Amortization of debt discount, premium and expense	16,340	13,300	8,497	5,243	4,998
Interest component of rentals	7,900	7,377	13,690	11,421	12,478
Fixed Charges	$ 278,117	$ 281,428	$ 326,575	$ 310,030	$ 296,874
Ratio of Earnings to Fixed Charges	4.72	4.68	3.49	3.83	3.65

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WARNING

FOR ARCHIVES

Do Not Damage Or Destroy

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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)
[x] ANNUAL REPORT PURSUANT TO SECTION 13
OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

For the fiscal year ended December 31, 1995

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION
13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the transition period from to

Commission File Number 1-4928

DUKE POWER COMPANY
(Exact name of registrant as specified in its charter)

North Carolina	56-0205520
(State Or Other Jurisdiction Of Incorporation Or Organization)	(I.R.S. Employer Identification No.)
422 South Church Street, Charlotte, North Carolina	28242-0001
(Address of principal executive offices)	(Zip Code)

704-594-0887
(Registrant's Telephone Number, Including Area Code)

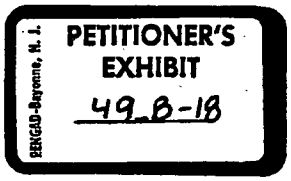
Securities Registered Pursuant To Section 12(b) Of The Act:

Title Of Each Class	Name Of Each Exchange On Which Registered
Common Stock, without par value	New York Stock Exchange, Inc.
Preferred Stock A, par value $25	
7.72%, 1992 Series	New York Stock Exchange, Inc.
6.375%, 1993 Series	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5-3/8% Due 1997	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5-7/8% Due 2001	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5-7/8% Series C Due 2003	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6-1/4% Series B Due 2004	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6-3/8% Due 2008	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6-5/8% Series B Due 2003	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6-3/4% Due 2025	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6-7/8% Series B Due 2023	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2000	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Series B Due 2000	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2005	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2033	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7-3/8% Due 2023	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7-7/8% Due 2024	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8% Series B Due 1999	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8% Due 2004	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8-3/8% Series B Due 2021	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8-5/8% Due 2022	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8-3/4% Due 2021	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7-1/2% Series B Due 2025	New York Stock Exchange, Inc.

Securities Registered Pursuant To Section 12(g) Of The Act:

Title Of Class
Preferred Stock, par value $100

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes (x) No



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Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (x)

Estimated aggregate market value of the voting stock held by nonaffiliates of the registrant at

March 8, 1996	$9,850,948,807
Number of shares of Common Stock, without par value, outstanding at March 8, 1996	204,859,339

Documents Incorporated By Reference:

The registrant is incorporating herein by reference certain sections of its proxy statement relating to the 1996 annual meeting of shareholders to provide information required by the following parts of this annual report:

Part III -- Item 10., Directors and Executive Officers of the Registrant
-- Item 11., Executive Compensation
-- Item 12., Security Ownership of Certain Beneficial Owners and Management
-- Item 13., Certain Relationships and Related Transactions

DUKE POWER COMPANY
FORM 10-K
ANNUAL REPORT TO
THE SECURITIES AND EXCHANGE COMMISSION
FOR THE YEAR ENDED DECEMBER 31, 1995
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DUKE POWER COMPANY
PART I.

Item 1. Business.

Duke Power Company (the Company) is primarily engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina,

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comprising the area in both states known as the Piedmont Carolinas. It is one of the nation's largest investor-owned electric utilities.

The Company is also engaged in a variety of diversified operations, most of which are organized in separate subsidiaries. The Company's subsidiaries and diversified activities are in the Associated Enterprises Group (AEG). AEG includes Church Street Capital Corp.; Crescent Resources, Inc.; Duke Energy Group, Inc.; Duke Engineering & Services, Inc.; Duke/Fluor Daniel; Duke Merchandising; DukeNet Communications, Inc.; Duke Water Operations; and Nantahala Power and Light Company (NP&L). For additional information on subsidiaries and diversified activities, see "Subsidiaries and Diversified Activities", "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- Subsidiaries and Diversified Operations" and "Subsidiaries and Diversified Activities Highlights".

During 1995, the Company's operating revenues, including AEG, were $4.7 billion. The Company's executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242-0001 (Telephone No. 704-594-0887).

Service Area

The Company's service area (excluding NP&L), approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 5.0 million and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville and Spartanburg in South Carolina. The Company supplies electric service directly to approximately 1.8 million residential, commercial and industrial customers in more than 200 cities, towns and unincorporated communities. Electricity is sold at wholesale to incorporated municipalities and to several public and private utilities. In addition, sales are made through contractual agreements to former wholesale municipal or cooperative customers of the Company who had purchased portions of the Catawba Nuclear Station (collectively, the "other Catawba joint owners") (See "Joint Ownership of Generating Facilities.") NP&L services an additional 53,000 mostly residential customers in five counties in western North Carolina.

The Company's service area is undergoing increasingly diversified industrial development. The textile industry, machinery and equipment manufacturing, and chemical and chemical-related industries are of major significance to the economy of the area. Other industrial activities include rubber and plastic products, paper and allied products, and various other light and heavy manufacturing and service businesses. The largest industry served is the textile industry, which accounted for approximately $494 million of the Company's revenues for 1995, representing 11 percent of electric revenues and 39 percent of industrial revenues.

Energy Requirements And Capability

The following table sets forth the Company's generating capability as of December 31, 1995, its sources of electric energy for 1995 and certain information presently projected for 1996:

Source	Generating Capability MW(a)(b)(c)		Generation MWH (thousands)(c)
	Actual December 31, 1995	Projected December 31, 1996	Actual 1995
Coal	7,699	7,699	32,389
Nuclear (d)	5,078	5,078	39,836
Hydro and other	4,166	4,466(e)	1,940
Total	16,943	17,243	74,165
Plus: Purchases from other Catawba joint owners			6,070
Purchased power and net interchange			1,175
Total			81,410

(a) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(b) Excludes firm purchases and sales. (See "Energy Management and Future Power Needs.")

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(c) Excludes NP&L.

(d) Nuclear capability and related generation for 1995 and related projections for 1996 reflect the Company's 12.5% ownership share of the Catawba Nuclear Station. (See "Joint Ownership of Generating Facilities".)

(e) Includes four units of the Lincoln Combustion Turbine Station with generating capacity of 300 MW which were placed into commercial operation in early 1996. (See "Capital Requirements.")

NP&L operates 11 hydroelectric stations with a total capacity of 100 megawatts and also purchases supplemental power. The Company supplies supplemental power to NP&L under the terms of an interconnection agreement approved by the Federal Energy Regulatory Commission (FERC).

The Company has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power agreement.

According to 1994 industry statistics published in 1996, the Company ranked first in the nation in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Published rankings indicate that individual units at Marshall Steam Station and Belews Creek Steam Station ranked first, third, fourth, fifth, eighth and tenth most efficient in the nation in 1994. The Company's nuclear system continued its tradition of operating efficiency, operating at 90 percent of capacity for 1995, in comparison with the industry's latest available average capacity factor of 74 percent for 1994. The Company's system nuclear capacity factor reflects the Company's 12.5% ownership share of the Catawba Nuclear Station.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The Company currently forecasts a 1.8 percent compound annual growth in peak load through 2010. An all-time peak load of 15,542 MW occurred on August 14, 1995 during exceptionally warm summer weather. This peak load excludes the portion of the demand of the other joint owners of the Catawba Nuclear Station met by their retained ownership.

Rate Matters

The North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC) must approve the Company's rates for retail sales within their respective states. The FERC must approve the Company's rates for sales to wholesale customers, including the contractual arrangements between the Company and the other Catawba joint owners.

The most recent general rate increase requests in the Company's retail jurisdictions were filed and approved in 1991. The Company also filed its most recent general rate increase request within the FERC wholesale jurisdiction in 1991. A negotiated settlement between the Company and the wholesale customers was approved by the FERC in 1992.

In its most recent general rate case, the NCUC authorized a jurisdictional rate of return on common equity of 12.50 percent, and the PSCSC authorized a jurisdictional rate of return on common equity of 12.25 percent.

During 1992, NP&L filed an application for a general rate increase with the NCUC. A general rate increase was approved in June 1993.

Fuel And Purchased Power Cost Adjustment Procedures. Duke Power has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The North Carolina legislature enacted a statute in 1987 assuring the legality of adjustments of past over- and under-recovery of fuel costs in rates. The North Carolina legislature repealed the expiration provision of this statute in March 1995. In the North Carolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings. Fuel costs are reviewed semiannually in the wholesale and South Carolina retail jurisdictions. All jurisdictions allow Duke Power to adjust rates for past over- or under-recovery of fuel costs. Therefore, Duke Power reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

Construction Work In Progress (CWIP). The NCUC is permitted in its discretion to include CWIP in rate base after giving consideration to the public interest and the Company's financial stability. The PSCSC may include CWIP in rate base in its discretion.

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Energy Management And Future Power Needs

The Company's strategy for meeting customers' present and future energy needs is composed of three components: demand-side resources, purchased power resources and supply-side resources. By utilizing these resources, the Company expects to maintain a reserve margin of approximately 18 to 20 percent of its anticipated peak load requirements through 2000. The Company continues to engage in a comprehensive energy management program as part of its Integrated Resource Plan (IRP). Integrated resource planning is the process used by utilities to evaluate a variety of resources. The goal is to provide adequate and reliable electricity in an environmentally responsible manner through cost-effective power management. The Company files an IRP with the NCUC and the PSCSC once every three years. During each of the intervening years, the Company files a Short Term Action Plan which updates the IRP for any changes in projections for the next three years. The PSCSC issued an order on December 14, 1995 approving the Company's 1995 IRP. On February 20, 1996, the NCUC issued a similar order.

Demand-side management (DSM) programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for DSM programs and allowed the deferral for later recovery of certain DSM costs that exceed the level reflected in rates, including a return on deferred costs. In 1993, the NCUC and the PSCSC issued orders approving "shared savings" mechanisms for accomplishments achieved in the Company's DSM programs,

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and deferral of such shared savings. The Company ultimately expects recovery through rates of associated deferred costs, not to exceed $75 million including deferred returns in the North Carolina retail jurisdiction. The annual costs deferred, including the return, were approximately $27 million in 1995 and $25 million in 1994. The total costs deferred, including the return, are $58 million and $38 million in North Carolina and South Carolina, respectively.

The purchase of capacity and energy is an integral part of meeting future power needs. As of December 31, 1995, the Company had under contract 300 MW of capacity from other generators of electricity, including 62 MW from qualifying facilities. In 1995, the Company issued two requests for proposals (RFP) to solicit competitive bids for its future electric generating capacity resources. The short-term RFP could provide options for up to 675 megawatts of capacity with terms of 1 to 4 years. The long-term RFP solicits bids to provide up to 300 megawatts of purchased power to be available beginning in 1998 or 1999, for contract periods of between 5 and 20 years in duration. The Company has evaluated a total of 16 proposals received for both the short-term RFP and the long-term RFP and has begun negotiation with the bidders with the best proposals. Contracts are expected to be awarded in May 1996.

Capital Requirements

Projected capital expenditures, excluding costs related to portions of the Catawba Nuclear Station owned by the other Catawba joint owners, for the years set forth below, are as follows (in millions):

	1996	1997	1998	1999	2000	Total
Duke Power - Electric						
Generation	$ 193	$ 210	$ 124	$ 115	$ 132	$ 774
Transmission	40	41	42	42	42	207
Distribution	199	198	199	200	201	997
Other	72	64	65	60	60	321
Nuclear Fuel	120	136	116	164	125	661
Total Duke Power - Electric	624	649	546	581	560	2,960
Associated Enterprises Group	226	194	178	206	219	1,023
Total Company	$ 850	$ 843	$ 724	$ 787	$ 779	$ 3,983

The Company's procedures for estimating capital expenditures for Duke Power - Electric (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs, allowances for inflation and the Company's business plan. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances for Duke Power - Electric are due to various factors,

including revised load estimates, environmental matters and cost and availability of capital. Projections of the AEG capital expenditures are subject to periodic review and revision and may vary significantly as the business plans of AEG evolve to meet the opportunity presented by its markets.

The Company has substantially completed construction of a combustion turbine facility in Lincoln County, North Carolina to provide capacity at periods of peak demand. The Lincoln Combustion Turbine Station consists of 16 combustion turbines with a total generating capacity of 1,200 megawatts. The estimated total cost of the project is approximately $400 million. Twelve of the 16 units were placed into commercial operation in 1995, and as of March 1, 1996, the final four units were placed into commercial operation. During 1991, the NCUC granted the Certificate of Public Convenience and Necessity and the North Carolina Division of Environmental Management issued a final air permit for the facility. All appeals related to the issuance of the final air permit were resolved in 1995.

Joint Ownership Of Generating Facilities

In order to reduce its need for external financing, the Company, through several transactions beginning in 1978, sold an 87 1/2 percent undivided interest in the Catawba Nuclear Station to the other Catawba joint owners.

These transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use (whether or not the facility is generating electricity) that portion of the capacity not then contractually required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The transactions also include a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station of the Company, which provides for an exchange of 50 percent of each other Catawba joint owner's retained capacity from its ownership interest in the Catawba units for like amounts of capability and output from units of the McGuire Nuclear Station. The implementation of the reliability exchange has not had, nor does the Company anticipate that such implementation will have, a material effect on earnings. (See Note 3, "Notes to Consolidated Financial Statements.")

The Company and North Carolina Municipal Power Agency Number 1 (NCMPA) and Piedmont Municipal Power Agency (PMPA), two of the four other joint owners of the Catawba Nuclear Station, entered into a settlement in September 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the NCUC on January 16, 1996 and the PSCSC on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3, "Notes to Consolidated Financial Statements.") In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Fuel Supply

The Company presently relies principally on nuclear fuel and coal for the generation of electric energy. The Company's reliance on oil and gas is minimal and will remain minimal even with the addition of the Lincoln Combustion Turbine Station, which is designed to operate on either natural gas or oil.

nuclear fuel + coal

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Information regarding the utilization of sources of power and cost of fuels is set forth in the following table:

	Generation by Source			Cost of Fuel per Net KWH Generated (Cents)		
	Year Ended December 31			Year Ended December 31		
	1995	1994	1993	1995	1994	1993
Coal	43.7%	46.9%	48.6%	1.56	1.54	1.61
Nuclear (1)	53.7%	51.0%	49.1%	0.57	0.56	0.53
Oil and gas	--	--	--	--	--	--
All Fuels (cost based on weighted average) (1)	97.4%	97.9%	97.7%	1.03	1.03	1.07
Hydroelectric (2)	2.6%	2.1%	2.3%			
	100.0%	100.0%	100.0%			

(1) Statistics related to nuclear generation and all fuels reflect the Company's 12.5% ownership in the Catawba Nuclear Station.

(2) Generating figures are net of that output required to replenish pumped storage units during off-peak periods and do not include NP&L.

Coal. The Company obtains a large amount of its coal under long-term supply contracts with mining operators utilizing both underground and surface mining. The Company has on hand an adequate supply of coal. The Company's long-term supply contracts, all of which have price adjustment provisions, have expiration dates ranging from 1996 to 2003. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers for quantities and qualities of coal required. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. The Company's requirements not met by long-term supply contracts have been and will be fulfilled with spot market purchases. The average sulfur content of coal being purchased by the Company is approximately 1 percent. Such coal satisfies the current emission limitation for sulfur dioxide for existing facilities. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- The Clean Air Act Amendments of 1990.")

Nuclear. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, enrichment of that gas and fabrication of the enriched uranium hexafluoride into usable fuel assemblies. After a region (approximately one-third of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations. Based upon current projections, these contracts will meet the Company's requirements through the following years:

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1997	1998	2000	2006
McGuire	1997	1998	2000	2009
Catawba	1997	1998	2000	2009

Uranium material requirements will be met through various supplier contracts, with uranium material produced primarily in the U.S. and Canada. The Company believes that it will be able to renew contracts as they expire or to enter into similar contractual arrangements with other nuclear fuel materials and services suppliers. Requirements not met by long-term supply contracts have been and will be fulfilled with uranium spot market purchases.

The Department of Energy (DOE) recently requested Expressions of Interest (EOI) to facilitate in the disposal of plutonium. The Company and Commonwealth Edison, along with the other joint owners of the Catawba

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Nuclear Station, responded to the EOI in early 1996. As this project is in its early developmental stage, management cannot predict the outcome of this process. However, the Company believes these matters should not have a material effect on the results of operations or financial position of the Company.

The Nuclear Waste Policy Act of 1982 requires that the DOE begin disposing of spent fuel no later than January 31, 1998. The Company has entered into the required contracts with the DOE for the disposal of nuclear fuel and began making payments in July 1983 for disposal costs of fuel currently being utilized. These payments, combined with a one-time payment for disposal costs of fuel consumed prior to April 7, 1983, have totaled about $510 million through 1995 related to the Company's ownership interest in nuclear plants. In December 1995, the DOE released a report which indicated that it expects a facility for spent fuel disposal will not be available until the year 2015. The DOE continues to pursue a centralized interim storage facility, with a target operation date of 1998, for earlier acceptance of spent fuel from utilities. The Company believes that it will be able to provide adequate on-system storage capacity until such time as the DOE begins receiving spent fuel.

Regulation

The Company is subject to the jurisdiction of the NCUC and the PSCSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of the FERC, the Environmental Protection Agency (EPA) and state environmental agencies and to the jurisdiction of the Nuclear Regulatory Commission (NRC) as to design, construction and operation of its nuclear power facilities. The Company is exempt from regulation as a holding company under the Public Utility Holding Company Act of 1935, except with respect to the acquisition of the securities of other public utilities.

Environmental Matters. The Company is subject to federal, state, and local regulations with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. North Carolina has enacted a declaration of environmental policy requiring all state agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. South Carolina law also requires consideration by the PSCSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed major utility facilities, which include certain generation and transmission facilities. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. In 1995, the Company's construction costs for environmental protection totaled approximately $52 million, while the on-going environmental operation costs were approximately $25 million. The Company's 1996-2000 construction program includes costs for environmental protection which are estimated to be approximately $40 million, including $9.8 million in 1996, $4.1 million in 1997, $7.4 million in 1998, $9.7 million in 1999 and $9.4 million in 2000. These costs include expenditures associated with the Clean Air Act Amendments of 1990. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. These projections are subject to periodic review and revisions. Actual construction costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including cost and availability of capital.

AIR QUALITY. See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- The Clean Air Act Amendments of 1990" for a discussion of the Company's plans for compliance with federal clean air standards.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1987 (referred to herein as the "Clean Water Act") require permits for facilities that discharge into waters. The Company holds numerous such permits, which are issued periodically. The issuance of such permits is delegated by the EPA to state agencies in North and South Carolina. The Clean Water Act has been scheduled for review and reauthorization by Congress since 1994, but no legislation has been enacted. Until Congress acts upon the reauthorization, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

OTHER ENVIRONMENTAL REGULATIONS. Contingencies associated with environmental matters are principally related to possible obligations to remove or mitigate the effects on the environment resulting from the disposal of certain substances at contamination sites.

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The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as "Superfund", requires any individual or entity which may have owned or operated a contaminated site, as well as transporters or generators of hazardous wastes which were sent to such site, to assume joint and several responsibility for remediation of the site. Such parties are known as "potentially responsible parties" (PRPs). Some contamination sites are remediated pursuant to state acts which are similar to CERCLA. The Company has participated in site remediation activities in the past as a PRP at Superfund sites or similar state sites in the Charlotte area, near Chester, S.C., and in Pennsylvania and West Virginia. The Company's involvement in one Superfund site and one state site was resolved in early 1996. The Company is currently participating in PRP groups with regard to Superfund sites in Concord, North Carolina and Lenoir, North Carolina. While the total cost of remediation at these federal and state contamination sites may be substantial, the Company shares probable liability with other PRPs, many of which have substantial assets. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

Other contamination sites in which the Company is involved arise from the operation of manufactured gas plant (MGP) sites, which were commonplace in the Carolinas until the 1950s. Some such sites are still owned by the Company, and others are now owned by third parties. In North Carolina, the Company is participating in a state-sponsored program to investigate and, where appropriate, remediate MGP sites. In South Carolina, the Company is in the process of remediating an MGP site in Greenville. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

CERCLA has been scheduled for review and reauthorization by Congress since 1994, but has not been examined outside of the legislative committee structure. Until CERCLA reform occurs, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

GENERAL. Over the past few decades, the issue of the possible health effects of electric and magnetic fields has generated a number of generally inconclusive studies, some public concern and litigation as well as legislative action in some states regarding high voltage transmission lines. The impact of this issue on the Company cannot presently be determined.

Nuclear Facilities. The Company's nuclear facilities are subject to continuing regulation by the NRC.

Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company is planning for the replacement of steam generators at three units that have experienced SCC and has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. The current schedule for completion of the effort is as follows: Catawba Unit 1 -- 1996, McGuire Unit 1 -- 1997 and McGuire Unit 2 -- 1997. The order of replacement is subject to change based on operational and project circumstances. The Catawba Unit 2 steam generators have not been scheduled for replacement. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $170 million per unit, excluding the cost of replacement power and the reimbursement of applicable costs by the other Catawba joint owners for Catawba Unit 1. The $170 million per unit cost estimate includes the cost of removal of steam generators being replaced. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the other joint owners, began a legal action in 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba Stations steam generators that were defective in design, workmanship and materials, requiring replacement well short of their stated design life. The lawsuit was settled in 1994. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the results of operations or financial position of the Company.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion

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stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible

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for decommissioning costs related to their ownership interests in the station. Both the NCUC and the PSCSC have granted the Company recovery of the estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume that units will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 -- 2013, Oconee 3 -- 2014; McGuire 1 -- 2021, McGuire 2 -- 2023; and Catawba 1 -- 2024, Catawba 2 -- 2026.

The NRC issued a rulemaking in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1995, the Company expensed approximately $56 million, which was contributed to the external funds and accrued an additional $1 million to the internal reserve. The balance of the external funds as of December 31, 1995, was $273 million. The balance of the internal reserve as of December 31, 1995, was $206 million and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid approximately $9.2 million during 1995 and $35.6 million cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of approximately $101 million in the Consolidated Balance Sheets at December 31, 1995.

Nuclear Insurance. For a discussion of the Company's nuclear insurance coverage, see "Note 13, Notes to Consolidated Financial Statements, Commitments and Contingencies -- Nuclear Insurance."

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of approximately 805 MW, are licensed for a term expiring in 2008. The Company also holds a license for the Keowee-Toxaway Project for a term expiring in 2016, covering the Keowee Hydro Station and the Jocassee Pumped Storage Station for a combined total of approximately 770 MW, on the upper tributaries of the Savannah River in northwestern South Carolina. Additionally, the Company is the licensee through 2027 for the Bad Creek Hydroelectric Station which uses Lake Jocassee as its lower reservoir and has a nameplate rating of 1,065 MW. NP&L holds licenses for 11 hydroelectric projects with a nameplate rating of 100 MW with license terms expiring 2001-2006. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

The Company has major interconnections and arrangements with its neighboring utilities which it currently considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

Competition

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems, rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSCSC, respectively, of all areas outside municipalities in such states to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of

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the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSCSC. In addition, the Company is engaged in continuing competition with various natural gas providers.

The Energy Policy Act of 1992 (EPACT) is a major driver towards a more competitive market for wholesale sales of power. EPACT reformed provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, EPACT allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. In addition, EPACT permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that independent suppliers can sell at wholesale to customers wherever located. It does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

The FERC, responsible in large measure for implementation of the EPACT, has moved vigorously to implement its mandate, interpreting the statute broadly in issuing orders for third-party transmission service and issuing a number of rules of general applicability. The FERC, in late March of 1995, issued a Notice of Proposed Rulemaking (the "NOPR") in which it announced its intent to impose a final rule, applicable to all electric utilities subject to its jurisdiction, which will require all such utilities to adopt open-access transmission tariffs containing identical terms and conditions. The FERC should issue its final rule in 1996.

Open transmission access for wholesale customers as contemplated by the FERC's NOPR would provide energy suppliers, including the Company, with opportunities to sell and deliver capacity and energy at market-based prices. Engaging in such transactions could result in improved utilization of the Company's existing assets. In addition, such access would provide another supply option through which the Company can buy capacity and energy at attractive rates, influencing its competitive price position. However, sales to existing wholesale customers of the Company could be impacted by open access as contemplated by the NOPR either due to competitive pressure on the wholesale price of electricity, or the potential loss of sales as wholesale customers seek other options to meet their capacity and energy requirements at market-based prices. Wholesale sales, excluding transactions with other utilities, represented approximately 6.7 percent of the Company's total kilowatt-hour sales in 1995. Supplemental sales to the other joint owners of the Catawba Nuclear Station comprised the majority of such sales. Such supplemental sales will be declining in 1996 as a result of the retention of significantly larger portions of ownership entitlement by the other joint owners. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

In early 1995, prior to issuance of the FERC's NOPR, the Company and certain of its affiliates filed three applications with the FERC, all of which are designed to enable effective participation in the competitive environment of the changing electric utility industry. Duke Power filed an application for permission to sell at market-based rates up to 2,500 megawatts of capacity and energy from its own assets. Two of the Company's affiliates, Duke Energy Marketing Corporation (DEMC) and Duke/Louis Dreyfus L.L.C. (D/LD), filed applications with the FERC to become power marketers. All of the applications were supported by transmission tariffs which establish the rates, terms and conditions for transmission service to third parties on the Company's transmission system.

Late in 1995, the FERC granted the applications of Duke, DEMC, and D/LD; accepted Duke's transmission tariffs; and ordered a hearing on the rates to be charged for service under those tariffs. The terms and conditions of service are subject to the outcome of the FERC's final rule, and the rates are subject to the outcome of hearings before the FERC.

Wheeling of third party energy to a retail customer is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states regarding retail competition which could result in changes in the industry.

Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based price of electricity, profits could be reduced and utilities might be required to reduce their recorded asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require affected utilities to write off their associated

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regulatory assets. The regulatory assets of the Company are classified as "Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

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Subsidiaries And Diversified Activities

The Company continues to aggressively pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Although these opportunities are primarily concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. The Company undertakes a continuous evaluation of the various lines of business it may enter or exit, with the objectives of enhancing shareholder value and managing any associated risk. (See "Subsidiaries and Diversified Activities Highlights".)

Major subsidiaries and diversified activities include the following:

Crescent Resources, Inc. (Crescent) pursues both residential and commercial real estate development, in addition to providing forest management activities focused on growing trees suitable for use in the construction, furniture and paper industries. At December 31, 1995, Crescent owned approximately 2,398,000 square feet of office, retail and warehouse space and had approximately 400,000 square feet of commercial properties under construction. Additionally, Crescent had approximately 250,000 acres of land under its management at year end.

Duke Energy Group, Inc. (Duke Energy) develops, owns and manages electric power facilities in the United States and abroad. Duke Energy also markets electric power and natural gas through a joint venture with Louis Dreyfus Electric Power. Domestically, Duke Energy concentrates on advanced fossil-fueled generation including pulverized coal, circulating fluidized bed, coal gasification and natural gas technologies. Internationally, Duke Energy pursues advanced coal-fueled, hydroelectric and gas-fueled generation as well as transmission projects. Duke Energy has equity interests in two U.S. electric generation facilities and four international projects.

Nantahala Power and Light Company (NP&L) is a franchised electric utility which operates 11 hydroelectric plants with a total capacity of 100 megawatts. NP&L has approximately 53,000 customers in western North Carolina. NP&L sold 949,000 MWH in 1995 compared to 907,000 MWH in 1994, excluding sales to Duke Power.

Other Business Units include Church Street Capital Corp., which manages investment funds and provides equity funding and credit enhancements for its subsidiaries; Duke Engineering & Services, Inc., which markets engineering, construction, quality assurance, consulting and other engineering-related services for facilities other than coal-fired generating plants, both nationally and internationally; Duke/Fluor Daniel, a joint venture with Fluor Daniel, Inc., which provides engineering, construction and support of operating and maintenance activities, primarily for coal-fired generating plants, both nationally and internationally; Duke Merchandising, which sells and services quality electric appliances and electronics; DukeNet Communications, Inc., which develops and manages communications systems; and Duke Water Operations, which provides franchised water services for Anderson, South Carolina and Rutherfordton, North Carolina.

Employees

At December 31, 1995, the Company had 17,121 full-time employees, which included 1,355 full-time employees of subsidiaries and diversified activities. About 1,950 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW). During the last quarter of 1995, the Company reached new labor agreements with the IBEW for one year terms.

The number of full-time employees has decreased to the 1995 year-end level from 19,945 at year-end 1990. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- Resource Optimization.")

Subsequent Event

The Company's Board of Directors has authorized the implementation of a program to repurchase up to $1 billion of the Company's Common Stock from time to time over the next five years. The repurchases will be made either on the open market (in accordance with applicable regulations) or through privately negotiated transactions. The Board's authorization provides flexibility for the Company's management to undertake the repurchase program at its discretion, and does not establish a target stock price or timetable for repurchases. The timing and amount of repurchases will be determined by cash available to the Company for such purpose and by the availability of alternative investment opportunities.

(A Map of North Carolina and South Carolina appears here showing Duke Power's service area. The legend is as follows:)

LEGEND
(star) REGION OFFICE
(circle) FOSSIL-FUELED STATION
(triangle) HYDROELECTRIC STATION
(square) NUCLEAR ELECTRIC STATION
(open box) NANTAHALA POWER AND LIGHT

DUKE POWER COMPANY
OPERATING STATISTICS

	Year ended December 31				
	1995	1994	1993	1992	1991
Sources of Electric Energy (d)					
Millions of kilowatt-hours:					
Generated--net output:					
Coal	32,389	32,714	34,097	28,999	26,455
Nuclear (a)	39,036	35,587	34,390	33,925	37,048
Hydro (b)	1,685	1,460	1,582	1,834	1,545
Oil and gas (c)	255	35	43	5	7
Total generation	74,165	69,796	70,112	64,763	65,055
Purchased power and net interchange	1,175	1,276	1,750	1,403	587
Total output	75,340	71,072	71,862	66,166	65,642
Plus: Purchases from other Catawba joint owners	6,070	9,046	8,810	9,466	8,525
Total sources of energy	81,410	80,118	80,672	75,632	74,167
Line loss and company usage	4,673	4,555	4,614	4,590	4,280
Total kilowatt-hour sales	76,737	75,563	76,058	71,042	69,887
Average cost per ton of coal burned	$ 41.72	$ 40.68	$ 42.21	$ 43.47	$ 45.21
Electric Energy Sales (d)					
Millions of kilowatt-hours:					
Residential	19,669	18,870	19,465	17,789	17,91
General service	18,160	17,289	16,904	15,818	15,58
Industrial	12,151	12,285	11,954	11,685	11,3
Textile	17,631	17,005	16,244	15,356	14,9
Other	8,330	10,274	11,337	10,360	10,1
Other energy and wholesale (e)	75,941	75,723	75,904	71,008	69,
Total kilowatt-hour sales billed	796	(160)	154	34	(
Unbilled kilowatt-hour sales	76,737	75,563	76,058	71,042	69,
Total kilowatt-hour sales					
Electric Revenue (d)					
Thousands of dollars:					
Residential	$1,441,362	$1,379,740	$1,424,173	$1,312,227	$1,27
General service	1,076,791	1,031,061	1,014,124	964,853	92
Industrial	494,066	498,190	487,576	482,172	4
Textile	766,750	745,154	726,199	696,413	6
Other	461,367	540,256	476,862	460,849	4
Other energy and wholesale (e)	182,102	84,928	152,742	44,970	
Other electric revenue	$4,422,438	$4,279,329	$4,281,876	$3,961,484	$3,
Total electric revenues	1,526,323	1,493,166	1,460,876	1,439,845	1,
Number of Customers--end of year (d)	246,276	239,355	232,272	227,675	
Residential	1,390	1,422	1,396	1,390	
General service (f)	7,320	7,320	7,338	7,314	
Industrial	8,470	8,187	7,957	7,773	
Textile	1,789,779	1,749,450	1,709,829	1,683,997	
Other energy and wholesale	1,514,434	1,483,497	1,455,609	1,431,403	
Total customers	12,988	12,720	13,272	12,427	
Residential Customer Statistics (d)	951.75	$ 930.06	$ 978.40	$ 916.74	
Average number for the year					
Average annual use--KWH					
Average annual billing					
Average annual billed revenue per KWH (d)					
Cents:					
Residential	7.33	7.31	7.32	7.38	
General service	5.93	5.96	6.00	6.10	
Industrial	4.23	4.24	4.31	4.36	
Other energy and wholesale (e)	5.54	5.26	4.21	4.45	

(a) Includes 12.5% of Catawba generation.

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(b) 1991 includes KWH of the Bad Creek Hydroelectric Station prior to commercial operation.

(c) 1995 includes KWH of the Lincoln Combustion Turbine Station prior to commercial operation.

(d) Does not include operating statistics of NP&L.

(e) Includes sales to NP&L.

(f) 1991 restated to eliminate certain duplicate customers.

EXECUTIVE OFFICERS OF THE COMPANY

WILLIAM H. GRIGG, 63, Chairman of the Board and Chief Executive Officer. Mr. Grigg served as Chairman of the Board, President and Chief Executive Officer, effective April 28, 1994, until July 27, 1994 when he assumed his present position. He served as Vice Chairman of the Board beginning in 1991, and Executive Vice President, Customer Group, beginning in 1988.

STEVE C. GRIFFITH, JR., 62, Vice Chairman of the Board and General Counsel. Mr. Griffith served as Executive Vice President and General Counsel from 1991 until he assumed his present position in July 1994. He served as Senior Vice President and General Counsel from 1982 until 1991.

RICHARD B. PRIORY, 49, President and Chief Operating Officer. Mr. Priory served as Executive Vice President, Power Generation Group, from 1991 until he assumed his present position in July 1994. He was Senior Vice President, Generation and Information Services, from 1988 to 1991.

WILLIAM A. COLEY, 52, President, Associated Enterprises Group. Mr. Coley was named Senior Vice President, Power Delivery, in 1988; Senior Vice President, Customer Group, in 1990; and Executive Vice President, Customer Group, in 1991. He was named to his present position in July 1994.

RICHARD J. OSBORNE, 44, Senior Vice President and Chief Financial Officer. Prior to assuming his current position in July 1994, Mr. Osborne served as Vice President and Chief Financial Officer beginning in 1991 and Vice President, Finance, from 1988 to 1991.

JEFFREY L. BOYER, 39, Controller. Mr. Boyer served as Director of Corporate Accounting for more than five years prior to assuming his present position in July 1994.

Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

ITEM 2. Properties.

At December 31, 1995, the Company operated three nuclear generating stations, eight coal-fired stations and twenty-seven hydroelectric stations, all of which are located in North Carolina or South Carolina.

The following is a list of the major generating stations owned by the Company at December 31, 1995:

FACILITY	ENERGY SOURCE	NET MW
Oconee	Nuclear	2,538
McGuire	Nuclear	2,258
Catawba(a)	Nuclear	282
Belews Creek	Coal	2,240
Marshall	Coal	2,090
Allen	Coal	1,140
Cliffside	Coal	760
Others	Coal	1,469
Bad Creek	Hydroelectric	1,065
Jocassee	Hydroelectric	610
Others	Hydroelectric	1,007
Combustion turbines (b)	Oil and gas	1,484

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(a) Represents Duke's 12.5% ownership share in Catawba Nuclear Station.

(b) Includes 900 MW of the Lincoln Combustion Turbine Station which were in commercial operation as of December 31, 1995.

The Company has substantially completed the construction of the Lincoln Combustion Turbine Station, a 16-turbine facility designed to provide capacity at periods of peak demand. The station has a total generating capacity of 1,200 megawatts. Twelve of the 16 units were placed into commercial operation in 1995, and as of March 1, 1996, the final four units were placed into commercial operation. The facility is designed to operate on either natural gas or oil.

In addition to the electric generating plants described above, the Company owned, as of December 31, 1995, approximately 8,300 conductor miles of transmission lines and approximately 73,500 conductor miles of distribution lines. As of such date, the Company's transmission and distribution systems comprised approximately 1,600 substations with an installed transformer capacity of approximately 84,200,000 kVA.

NP&L's generation facilities consist of eleven hydroelectric plants with an aggregate nameplate capacity of approximately 100 MW. The transmission backbone of the system is a 161 kV line from Santeetlah to substations at Robbinsville, Nantahala Plant, Oak Grove, Webster and Thorpe Plant.

The map found at the end of Item 1 shows the location of the Company's and NP&L's service area and generating stations.

Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see "Business -- Energy Requirements and Capability."

ITEM 3. Legal Proceedings.

Reference is made to "Business -- Regulation", "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- Commitments and Contingencies" and "Note 13. Notes to Consolidated Financial Statements, Commitments and Contingencies -- Other".

ITEM 4. Submission Of Matters To A Vote Of Security Holders.

No matters were submitted to a vote of the Company's security holders during the last quarter of 1995.

PART II.

ITEM 5. Market For The Registrant's Common Equity And Related Stockholder Matters.

The Common Stock of the Company is traded on the New York Stock Exchange. At December 31, 1995, there were approximately 129,265 holders of shares of such Common Stock.

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by the New York Stock Exchange Composite Transactions:

Common Stock	Dividends Per Share	Stock Price Range High	Low
1995 By Quarter			
Fourth	$0.51	$47 7/8	$43 1/8
Third	0.51	43 3/4	40
Second	0.49	42 3/4	38 1/4
First	0.49	40 3/4	37 3/8
1994 By Quarter			
Fourth	$0.49	$42 1/8	$38
Third	0.49	39 7/8	35 1/2
Second	0.47	37	32 7/8
First	0.47	43	35 3/4

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ITEM 6. SELECTED FINANCIAL DATA

	1995	1994	1993	1992	1991
Condensed consolidated statements of income (thousands)					
Operating revenues	$ 4,676,684	$ 4,488,913	$ 4,466,211	$ 4,122,503	$ 3,962,605
Operating expenses	3,327,633	3,309,087	3,258,422	3,087,422	2,968,239
Operating income	1,349,051	1,179,826	1,207,811	1,035,081	994,366
Interest expense and other income	(168,072)	(143,931)	(171,419)	(223,028)	(117,725)
Income before income taxes	1,180,979	1,035,895	1,036,392	812,053	876,641
Income taxes	466,441	397,019	409,977	303,970	293,018
Net income	714,538	638,876	626,415	508,083	583,623
Dividends on preferred and preference stock	48,903	49,724	52,429	56,407	54,683
Earnings for common stock	$ 665,635	$ 589,152	$ 573,986	$ 451,676	$ 528,940
Common stock data					
Shares of common stock					
year-end (thousands)	204,859	204,859	204,859	204,859	204,689
average (thousands)	204,859	204,859	204,859	204,819	203,431
Per share of common stock					
Earnings	$ 3.25	$ 2.88	$ 2.80	$ 2.21	$ 2.60
Dividends	$ 2.00	$ 1.92	$ 1.84	$ 1.76	$ 1.68
Book value -- year-end	$ 23.36	$ 22.13	$ 21.17	$ 20.26	$ 19.86
Market price -- high-low	$ 47 7/8 - 37 3/8	$ 43 - 32 7/8	$44 7/8 - 35 3/8	$37 1/2 - 31 3/8	$ 35 - 26 3/
-- year-end	$ 47 3/8	$ 38 1/8	$ 42 3/8	$ 36 1/8	$ 35
Balance sheet data (thousands)					
Total assets	$ 13,358,484	$ 12,862,228	$ 12,293,605	$ 11,012,795	$ 10,617,9
Long-term debt	$ 3,711,405	$ 3,567,122	$ 3,265,397	$ 3,288,111	$ 3,235,4
Preferred stock with sinking fund requirements	$ 234,000	$ 279,500	$ 281,000	$ 279,519	$ 228,

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION.

RESULTS OF OPERATIONS

EARNINGS AND DIVIDENDS

Earnings per share increased 13 percent from $2.88 in 1994 to $3.25 in 1995. The increase was primarily due to increased kilowatt-hour sales to weather sensitive classes.

Earnings per share increased from $2.80 in 1993 to $3.25 in 1995, indicating an average annual growth rate of 8 percent. Total Company earned return on average common equity was 14.3 percent in 1995 compared to 13.3 percent in 1994 and 13.6 percent in 1993.

The Company continued its practice of annually increasing the common stock dividend. Common dividends per share increased at an average annual rate of 4 percent from $1.84 in 1993 to $2.00 in 1995. Indicated annual dividends per share increased to $2.04.

REVENUES AND SALES

Operating revenues increased at an average annual rate of 2 percent from 1993 to 1995, primarily because of increased retail kilowatt-hour sales to weather sensitive classes and growth in the general service and industrial customer classes. As discussed below, increased retail sales were partially offset by decreased sales to wholesale customers. Revenues from subsidiaries and diversified operations contributed $73 million to the increase in revenues over the three-year period, primarily from increased developed lot and land sales and engineering services and construction fees.

Wholesale revenues declined in 1995 and are expected to decline again in 1996 as a result of the retention of significantly larger portions of ownership entitlement by the other joint owners of the Catawba Nuclear Station. This increased retention reduces the joint owners' supplemental requirements supplied by the Company. The effect on earnings of such wholesale revenue declines is

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partially offset by declines in purchased power costs from the other joint owners which are not subject to levelization. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

Kilowatt-hour sales from Duke Power electric operations increased 2 percent in 1995 compared to 1994. Sales to residential, general service and other industrial customers increased by 4 percent, 5 percent and 4 percent, respectively, as a result of warmer summer weather, cooler winter weather and continued economic growth in Duke Power's service area. However, sales to textile customers decreased 1 percent. Wholesale sales decreased 19 percent primarily due to a decrease of 36 percent in supplemental sales requirements to the other joint owners of the Catawba Nuclear Station. A new record peak demand of 15,542 megawatts was set in August 1995 during warmer than normal temperatures.

OPERATING EXPENSES

From 1994 to 1995, other operation and maintenance expenses increased 5 percent. Increased activities of the subsidiaries and diversified operations associated with both engineering services and other project development efforts contributed to this increase. Increases in distribution and transmission expenses were offset by reductions in nuclear and fossil outage costs. In 1995 and 1994, the Company had relatively constant costs associated with work force reduction programs and certain claims that are expected to be non-recurring in nature.

Other operation and maintenance expenses increased at an average annual rate of 6 percent from 1993 to 1995. Costs associated with the enhanced vested retirement benefit program in 1995 as well as other non-recurring costs contributed to this increase in addition to increased activities of the subsidiaries and diversified operations associated with engineering services and other project development efforts. (For additional information on the vested retirement program, see Current Issues, "Resource Optimization.")

Fuel expense increased at an average annual rate of 1 percent from 1993 to 1995. The increase was due primarily to higher system production requirements, offset by improved nuclear generation.

Net interchange and purchased power expenses decreased from $535 million in 1993 to $468 million in 1995, an average annual decrease of 6 percent. This decrease was primarily the result of lower purchased power costs from the other joint owners not subject to levelization as the other joint owners retained significantly larger portions of their ownership entitlement. In 1996, net interchange and purchased power is expected to decrease again as purchased power costs from the other joint owners continue to decline.

From 1993 to 1995, depreciation and amortization expense decreased at an average annual rate of 4 percent, primarily because the reduction in the amortization of property losses more than offset increased depreciation associated with additional investments. These investments were primarily associated with distribution plant, including investment to support customer growth, commercial operation of 12 units of the Lincoln Combustion Turbine Station, and fossil plant resulting from bringing refurbished units back on-line. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs, "Meeting Future Power Needs.")

INTEREST EXPENSE AND OTHER INCOME

Interest expense increased at an average annual rate of 3 percent from 1993 to 1995, primarily due to long-term debt financing activities in 1994.

Allowance for funds used during construction (AFUDC) and other deferred returns, net of associated taxes, represented 13 percent of earnings for common stock in 1995 compared to 10 percent in 1993. AFUDC and other deferred returns are expected to be less than 11 percent of total earnings during the next three years.

The deferred return, net of associated taxes, on the purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station represented 7 percent of earnings for common stock in 1995, compared to 7 percent in 1994 and 6 percent in 1993. The growth in this return is due to the increasing cumulative impact of the Company's funding of purchased power costs through 1995, which the Company expects to collect through current rates in future periods. The deferred purchased capacity balance is expected to begin to decline in 1996. (For additional information on purchased capacity levelization, see Capital Needs, "Purchased Capacity Levelization.")

AFUDC, net of associated taxes, represented 5 percent of earnings for common stock in 1995 compared to 6 percent in 1994 and 4 percent in 1993. The changes were primarily the result of the construction and subsequent commercial operation of the Lincoln Combustion Turbine Station as 12 units were brought on-line at various times during 1995. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs, "Meeting Future Power Needs.")

LIQUIDITY AND RESOURCES

DUKE POWER COMPANY RATE MATTERS

The Company's most recent general rate increase requests in the North Carolina and South Carolina retail jurisdictions were filed and approved in 1991. Additionally, Duke Power has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all of Duke Power's regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

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CATAWBA SETTLEMENTS

The Company and North Carolina Municipal Power Agency Number 1 (NCMPA) and Piedmont Municipal Power Agency (PMPA), two of the four other joint owners of the Catawba Nuclear Station, entered into a settlement in September 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the North Carolina Utilities Commission (NCUC) on January 16, 1996 and the Public Service Commission of South Carolina (PSCSC) on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or the financial position of the Company.

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners, which previously have been approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.) In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years will conform to the settlement agreements, which were approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

CASH FROM OPERATIONS

Consolidated net cash provided by operating activities in 1995 accounted for 81 percent of total cash from operating, financing and investing activities compared with 67 percent in 1994 and 46 percent in 1993. When 1993 and 1995 refinancing activities are excluded, substantially all of the Company's capital needs were met by cash generated from operating activities. Refinancing activities were insignificant in 1994.

FINANCING AND INVESTING ACTIVITIES

The Company's consolidated capital structure at year-end 1995, including subsidiary long-term debt, was 52 percent common equity, 40 percent long-term debt and 8 percent preferred stock. This structure is consistent with the Company's target to maintain a double-A credit rating. As of December 31, 1995, Duke Power's bonds were rated "AA" by Fitch Investors Service, "Aa2" by Moody's Investors Service, and "AA-" by Standard & Poor's Group and Duff & Phelps.

The Company had total credit facilities of $669.9 million and $440.0 million as of December 31, 1995 and 1994, respectively. The Company had unused credit facilities of $440.6 million and $259.9 million as of December 31, 1995 and 1994, respectively.

In response to favorable market conditions in 1993, the Company issued $1.5 billion in long-term debt and $220 million in preferred stock, most of which was used to retire higher cost debt and preferred stock. In 1995, the Company issued $178 million of long-term debt, of which $72 million was used to retire higher cost long-term debt. The Company also retired $96 million of preferred stock and $80 million of long-term debt in 1995.

Capital Structure
Billions of dollars

(Bar graph appears here with the following plot points:)

	1990	1991	1992	1993	1994	1995
Long-term debt	40%	40%	40%	39%	40%	40%
Preferred and preference stock	10%	9%	9%	9%	9%	8%
Common equity	50%	51%	51%	52%	51%	52%
Total Amount	7.7	8.0	8.2	8.4	8.9	9.2

In order to obtain variable rate financing at an attractive cost, the Company entered into interest rate swap agreements associated with the November 29, 1994 issuance of $200 million aggregate principal amount of its First and Refunding Mortgage Bonds 8% Series B due 1999 and the August 21, 1995 issuance of $100 million aggregate principal amount of its First and Refunding Mortgage Bonds 7 1/2% Series B due 2025. The interest rate swaps are reset quarterly based upon the three-month London Interbank Offered Rate (LIBOR). As a result of the interest rate swap contracts, interest expense is recognized at the

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weighted average rate for the year tied to the LIBOR rate. The weighted average rates at December 31, 1995 and 1994 were 6.14% and 5.95%, respectively, for the 8% Series B due 1999 and 7.06% in 1995 for the 7 1/2% Series B due 2025.

The Company has also entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Japanese yen associated with various steam generator purchase contracts. The hedge transaction with a notional amount of approximately $25 million at December 31, 1994, was fully liquidated by November 1995. The Company recorded any gains or losses associated with the hedge as an adjustment to the capitalized cost of the steam generators.

Duke Energy Group, Inc. has entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Chilean peso associated with expected equity contributions over the next two years to a joint venture. The hedge transaction had a notional amount of approximately $17 million at December 31, 1995. Duke Energy Group, Inc. records gains or losses associated with the hedge as an adjustment to investments in joint ventures.

Duke Power's embedded cost of long-term debt, excluding debt of subsidiaries, was 7.94 percent for 1995 compared to 7.98 percent in 1994 and 8.01 percent in 1993. The embedded cost of preferred stock was 7.06 percent in 1995 compared to 6.99 percent in 1994 and 6.76 percent in 1993. The decreases in the embedded cost of long-term debt are primarily the result of the Company's refinancing activities and the resulting lower-cost debt. The increase in the embedded cost of preferred stock from 1993 to 1995 reflects the impact of increased adjustable dividend rates on a certain series of preferred stock and the retirement of preferred stock in 1995.

FIXED CHARGES COVERAGE

Consolidated fixed charges coverage using the SEC method increased to 4.94 times for 1995 compared to 4.72 and 4.68 times in 1994 and 1993, respectively. Coverage increased primarily because of higher earnings. Consolidated fixed charges coverage, excluding AFUDC and other deferred returns, was 4.52 times for 1995 compared with 4.32 in 1994 and 4.39 in 1993 and the Company goal of 3.5 times. Coverage was higher in 1995 than 1994 and 1993 as a result of increased earnings excluding AFUDC and other deferred returns.

Fixed Charges Coverage
Times

(Graph appears here with the following plot points:)

	1990	1991	1992	1993	1994	1995
SEC method	3.65	3.83	3.49	4.68	4.72	4.94
SEC method excluding AFUDC and other deferred returns	3.15	3.44	3.27	4.39	4.32	4.52

CAPITAL NEEDS

PROPERTY ADDITIONS AND RETIREMENTS

Additions to property and nuclear fuel of $794 million and retirements of $288 million resulted in an increase in gross plant of $506 million in 1995.

Since January 1, 1993, additions to property and nuclear fuel of $2.4 billion and retirements of $864 million have resulted in an increase in gross plant of $1.5 billion.

Duke Power Construction
Costs* Millions of dollars

(Graph appears here with the following plot points:)

	1990	1991	1992	1993	1994	1995
Nuclear fuel	141.2	193.0	127.8	121.8	128.6	89.4
Construction	909.7	606.6	464.0	547.6	650.3	583.1
Total	1050.9	799.6	591.8	669.4	778.9	672.5

*Includes AFUDC and excludes NP&L and Duke Power's other subsidiaries.

CONSTRUCTION EXPENDITURES

Plant construction costs for generating facilities supporting Duke Power electric operations, including AFUDC, increased from $162 million in 1993 to $281 million in 1995, primarily because of construction of the Lincoln Combustion Turbine Station and the steam generator replacement project. (For more information, see Capital Needs, "Meeting Future Power Needs" and Current Issues, "Stress Corrosion Cracking.") Construction costs for distribution plant, including AFUDC, decreased from $240 million in 1993 to $221 million in 1995.

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including AFUDC, are $2.3 billion and $661 million,

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respectively, for 1996 through 2000. These construction expenditures are primarily for distribution and production related activities representing $997 million and $774 million, respectively. These projections are subject to periodic reviews and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

Projected capital expenditures of subsidiaries and diversified activities are $1.0 billion for 1996 through 2000 of which a significant portion is for real estate development. These projections are subject to periodic review and revision and may vary significantly as the business plans of the Associated Enterprises Group evolve to meet the opportunity presented by its markets.

For 1996 through 2000, the Company anticipates substantially funding its projected construction and capital expenditures through the internal generation of funds.

PURCHASED CAPACITY LEVELIZATION

The rates established in Duke Power's electric retail jurisdictions permit recovery of its investment in both units of the Catawba Nuclear Station and the costs associated with contractual purchases of capacity from the other joint owners of the Catawba Nuclear Station. The contracts relating to the sales of portions of the station obligate the Company to purchase a declining amount of capacity from the other joint owners. In the North Carolina retail jurisdiction, regulatory treatment of these contracts provides revenue for recovery of the capital costs and the fixed operating and maintenance costs of purchased capacity on a levelized basis. In the South Carolina retail jurisdiction, revenues are provided for the recovery of the capital costs of purchased capacity on a levelized basis, while current rates include recovery of fixed operating and maintenance expenses.

Such rate treatments require the Company to fund portions of the purchased capacity payments until these costs, including returns, are recovered at a later date. The Company recovers the accumulated costs and returns when the sum of the declining purchased capacity payments and accrual of returns for the current period drop below the levelized revenues. In the North Carolina retail jurisdiction, and wholesale jurisdiction regulated by the Federal Energy Regulatory Commission (FERC), purchased capacity payments and the accrual of deferred returns continue to exceed levelized revenues. However, in 1996, the levelized revenues are expected to exceed the purchased capacity payments and accrual of deferred returns. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments and accrual of deferred returns. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups.

MEETING FUTURE POWER NEEDS

The Company's strategy for meeting customers' present and future energy needs consists of three components: supply-side resources, demand-side resources and purchased power resources. To assist in determining the optimal combination of these three resources, the Company uses an integrated resource planning process. The goal is to provide adequate and reliable electricity in an environmentally responsible, cost-effective manner.

The Company is constructing a combustion turbine facility in Lincoln County, North Carolina. The Lincoln Combustion Turbine Station, designed to provide capacity at periods of peak demand, will consist of 16 combustion turbines with a total generating capacity of 1,200 megawatts. The estimated total cost of the project is approximately $400 million. Units 1 through 12 began commercial operation during 1995 and the remaining four units are scheduled to begin commercial operation in 1996.

In 1995, the Company issued two requests for proposals (RFP) to solicit competitive bids for its future electric generating capacity resources. The short-term RFP could provide options for up to 675 megawatts of capacity with terms of 1 to 4 years. The long-term RFP solicits bids to provide up to 300 megawatts of purchased power to be available beginning in 1998 or 1999, for contract periods of between 5 and 20 years in duration. The Company has evaluated a total of 16 proposals received for both the short-term RFP and the long-term RFP and has begun negotiation with the bidders with the best proposals. Contracts are expected to be awarded in May 1996.

The purchase of capacity and energy is also an integral part of meeting future power needs. As of January 1, 1996, the Company has 300 megawatts of firm purchased capacity from other generators of electricity under contract, including 62 megawatts from qualifying facilities.

Demand-side management programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The Company ultimately expects recovery through rates of associated deferred costs, not to exceed $75 million including deferred returns in the North Carolina retail jurisdiction. The annual costs deferred, including the return, were approximately $16 million and $11 million in North Carolina and

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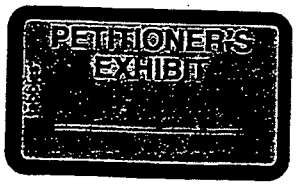
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CENTRAL INDEX KEY: 0000030371
STANDARD INDUSTRIAL CLASSIFICATION: ELECTRIC SERVICES [4911]
IRS NUMBER: 560205520
STATE OF INCORPORATION: NC
FISCAL YEAR END: 1231

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STATE: NC
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BUSINESS PHONE: 7045940887

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STATE: NC
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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
[Fee Required]
For the fiscal year ended December 31, 1996 or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
[No Fee Required]
For the transition period from to
COMMISSION FILE NUMBER 1-4928

DUKE POWER COMPANY
(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

<TABLE>
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North Carolina	56-0205520
(STATE OR OTHER JURISDICTION OF INCORPORATION OR ORGANIZATION)	(I.R.S. EMPLOYER IDENTIFICATION NO.)
422 South Church Street, Charlotte, North Carolina	28242-0001
(ADDRESS OF PRINCIPAL EXECUTIVE OFFICES)	(ZIP CODE)

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704-594-0887
(REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE)
SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:
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TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
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Common Stock, without par value	New York Stock Exchange, Inc.
Preferred Stock A, par value $25	
7.72%, 1992 Series	New York Stock Exchange, Inc.
6.375%, 1993 Series	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5 3/8% Due 1997	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5 7/8% Due 2001	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5 7/8% Series C Due 2003	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 1/4% Series B Due 2004	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 3/8% Due 2008	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 5/8% Series B Due 2003	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 3/4% Due 2025	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 7/8% Series B Due 2023	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2000	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Series B Due 2000	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2005	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2033	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7 3/8% Due 2023	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7 7/8% Due 2024	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8% Series B Due 1999	New York Stock Exchange, Inc.

First and Refunding Mortgage Bonds, 8% Due 2004 New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8 3/8% Series B Due 2021 New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8 5/8% Due 2022 New York Stock Exchange, Inc.
st and Refunding Mortgage Bonds, 8 3/4% Due 2021 New York Stock Exchange, Inc.
st and Refunding Mortgage Bonds, 7 1/2% Series B Due 2025 New York Stock Exchange, Inc.
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SECURITIES REGISTERED PURSUANT TO SECTION 12(G) OF THE ACT:
TITLE OF CLASS
Preferred Stock, par value $100

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes X No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

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Estimated aggregate market value of the voting stock held by nonaffiliates of the registrant at February 28, 1997..... $8,436,965,632
Number of shares of Common Stock, without par value, outstanding at February 28, 1997..... 201,589,596
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DOCUMENTS INCORPORATED BY REFERENCE:

The registrant is incorporating herein by reference certain sections of the nt Proxy Statement-Prospectus relating to the 1997 annual meeting of shareholders to provide information required by the following parts of this annual report:

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-- Item 11, Executive Compensation
-- Item 12, Security Ownership of Certain Beneficial Owners and Management
-- Item 13, Certain Relationships and Related Transactions
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DUKE POWER COMPANY
FORM 10-K
ANNUAL REPORT TO
THE SECURITIES AND EXCHANGE COMMISSION
FOR THE YEAR ENDED DECEMBER 31, 1996
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"SAFE HARBOR" STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995:

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes that its expectations are based on reasonable assumptions, no assurance can be given that actual results may not differ materially from those in the forward-looking statements herein for reasons that include: state and federal legislative and regulatory initiatives that increase competition, affect cost and investment recovery and have an impact on rate structures; the impact of competition from other energy suppliers; industrial, commercial and residential growth in the Company's service territory; the results of financing efforts; the effect of the Company's accounting policies; and growth in opportunities for the Company's subsidiaries and diversified operations, in each case during the periods covered by the foward-looking statements.

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DUKE POWER COMPANY

PART I.

ITEM 1. BUSINESS.

Duke Power Company (the Company) is primarily engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas. It is one of the nation's largest investor-owned electric utilities.

The Company is also engaged in a variety of diversified operations, most of which are organized in separate subsidiaries. The Company's subsidiaries and diversified activities are in the Associated Enterprises Group (AEG). AEG includes Church Street Capital Corp.; Crescent Resources, Inc.; Duke Energy

Group, Inc.; Duke Engineering & Services, Inc.; Duke/Fluor Daniel; Duke/Louis Dreyfus, LLC; Duke Merchandising; DukeNet Communications, Inc.; Duke Water Operations; and Nantahala Power and Light Company (NP&L). For additional information on subsidiaries and diversified activities, see "Subsidiaries and Diversified Activities," "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- Subsidiaries and Diversified Operations" and "Subsidiaries and Diversified Activities Highlights."

On November 25, 1996, the Company and PanEnergy Corp announced a proposed stock-for-stock transaction creating an integrated energy company. Upon consummation of the merger, PanEnergy will be a wholly owned subsidiary of the Company, and the Company's name will be changed to Duke Energy Corporation. The transaction is expected to close by December 31, 1997, subject to approval of the shareholders of both companies and all applicable regulatory approvals. The shareholders of each company will vote on the proposed merger at their annual meetings, which are scheduled for April 24, 1997 for both companies. Applications for regulatory approval were filed with the North Carolina Utilities Commission (NCUC) and The Public Service Commission of South Carolina (PSCSC) on December 19, 1996, and with the Federal Energy Regulatory Commission (FERC) on February 3, 1997. Regulatory proceedings are expected to be successfully completed by year-end 1997. In connection with the transaction, each share of PanEnergy common stock will be converted into 1.0444 shares of common stock of the Company. The transaction will be accounted for as a pooling of interests. Further details about the proposed acquisition are provided in the Company's reports on Form 8-K, filed with the Securities and Exchange Commission on December 9, 1996 and March 20, 1997, and in the Joint Proxy Statement-Prospectus provided to shareholders in connection with the Company's annual meeting. Unless otherwise indicated, all information presented in this Form 10-K relates to the Company only and does not take into account the proposed merger with PanEnergy.

During 1996, the Company's operating revenues, including AEG, were $4.8 billion. The Company's executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242-0001 (Telephone No. 704-594-0887).

SERVICE AREA

The Company's service area (excluding NP&L), approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 5.1 million and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville and Spartanburg in South Carolina. The Company supplies electric service directly to approximately 1.8 million residential, commercial and industrial customers in more than 200 cities, towns and unincorporated communities. Electricity is sold at wholesale to incorporated municipalities and to several public and private utilities. In addition, sales are made through contractual agreements to former wholesale municipal or cooperative customers of the Company who had purchased portions of the Catawba Nuclear Station (collectively, the "other Catawba joint owners") (See "Joint Ownership of Generating Facilities"). NP&L services an additional 55,000 mostly residential customers in five counties in western North Carolina.

The Company's service area is undergoing increasingly diversified industrial development. The textile industry, machinery and equipment manufacturing, and chemical and chemical-related industries are of major significance to the economy of the area. Other industrial activities include rubber and plastic products, paper and allied products, and various other light

and heavy manufacturing and service businesses. The largest industry served is the textile industry, which accounted for approximately $459 million of the Company's revenues for 1996, representing 10 percent of electric revenues and 37 percent of industrial revenues.

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ENERGY REQUIREMENTS AND CAPABILITY

The following table sets forth the Company's generating capability as of December 31, 1996, its sources of electric energy for 1996 and certain information presently projected for 1997:

<TABLE>
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SOURCE	GENERATING CAPABILITY -- MW(A)(B)(C) ACTUAL DECEMBER 31, 1996	PROJECTED DECEMBER 31, 1997	GENERATION -- MWH (THOUSANDS)(C) ACTUAL 1996
<S>	<C>	<C>	<C>
Coal	7,699	7,699	40,649
Nuclear (d)	5,078	5,078	33,177
Hydro and other	4,469	4,469	1,518
Total	17,246	17,246	75,344
Plus: Purchases from other Catawba joint owners			2,662
Purchased power and net interchange			3,587
Total			81,593

</TABLE>

(a) The data relating to capability does not reflect the possible unavailability or reduction of capability of facilities at any given time because of scheduled maintenance, repair requirements or regulatory restrictions.

(b) Excludes firm purchases and sales. (See "Energy Management and Future Power Needs.")

(c) Excludes NP&L.

(d) Nuclear capability and related generation for 1996 and related projections for 1997 reflect the Company's 12.5% ownership share of the Catawba Nuclear Station. (See "Joint Ownership of Generating Facilities.")

NP&L operates 11 hydroelectric stations with a total capacity of 100 megawatts and also purchases supplemental power. The Company supplies supplemental power to NP&L under the terms of an interconnection agreement approved by FERC.

The Company has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power agreement.

The Company's steam-fossil generating system continued its tradition of operating efficiently and achieved a combined availability of 86 percent for 1996. The Company's nuclear system operated at 74 percent of capacity for 1996, which reflects the impact of the steam generator replacement outage at the Catawba Nuclear Station (See "Regulation -- Nuclear Facilities") and the removal from service of the Oconee Nuclear Station in October 1996 for inspection and modification of the piping system after a steam line on the non-nuclear side of the plant ruptured. Oconee Units 1, 2, and 3 returned to service in 1997 on February 12, February 3, and March 14, respectively. The Company's system

nuclear capacity factor reflects the Company's 12.5% ownership share of the Catawba Nuclear Station.

The Company normally experiences seasonal peak loads in summer and winter ich are relatively in balance. The Company currently forecasts a 1.8 percent mpound annual growth in peak load through 2011. The Company experienced an all-time peak load of 15,542 MW on August 14, 1995 during exceptionally warm summer weather. This peak load excludes the portion of the demand of the other Catawba joint owners met by their retained ownership.

RATE MATTERS

The NCUC and the PSCSC must approve the Company's rates for retail sales within their respective states. The FERC must approve the Company's rates for sales to wholesale customers, including the contractual arrangements between the Company and the other Catawba joint owners.

The most recent general rate increase requests in the Company's retail jurisdictions were filed and approved in 1991. The Company also filed its most recent general rate increase request within the FERC wholesale jurisdiction in 1991. A negotiated settlement between the Company and the wholesale customers was approved by the FERC in 1992.

In its most recent general rate case, the NCUC authorized a jurisdictional rate of return on common equity of 12.50 percent, and the PSCSC authorized a jurisdictional rate of return on common equity of 12.25 percent.

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The PSCSC, on May 7, 1996, ordered a rate reduction in the form of a decrement rider of 0.432 cents per kilowatt-hour, or an average of approximately 8 percent, affecting South Carolina retail customers. South Carolina retail es represent approximately 30 percent of the Company's total retail sales. e rate reduction was reflected on bills rendered on or after June 1, 1996. This net decrement rider reflects an interim true-up decrement adjustment associated with the levelization of Catawba Nuclear Station purchased capacity costs and an interim true-up increment associated with amortization of the demand-side management deferral account. The rate adjustment was made because, in the South Carolina retail jurisdiction, cumulative levelized revenues associated with the recovery of Catawba purchased capacity costs had exceeded purchased capacity payments and accrual of deferred returns, and certain demand-side costs had exceeded the level reflected in rates.

Certain of the Company's wholesale customers, excluding the other Catawba joint owners, initiated proceedings in 1995 before the FERC concerning rate matters. The Company and nine of its eleven wholesale customers entered into a settlement in July 1996 which reduced the customers' rates by approximately 9 percent and renewed their contracts with the Company through the year 2000. Both of the customers that did not enter into the settlement have signed agreements to purchase energy from other suppliers beginning in 1997. The eleven wholesale customers involved in this matter accounted for less than 2 percent of the Company's overall electric revenues during 1996. The two customers that have signed agreements with other suppliers accounted for less than 0.5 percent of the Company's 1996 overall electric revenues.

During 1996, NP&L filed an application with and received approval from the NCUC to increase its annual retail service revenues by $4.6 million.

FUEL AND PURCHASED POWER COST ADJUSTMENT PROCEDURES. Duke Power has ocedures in all three of its regulatory jurisdictions to adjust rates for ctuations in fuel expense. In the North Carolina retail jurisdiction, a view of fuel costs in rates is required annually and during general rate case

proceedings. In 1996, the South Carolina General Assembly amended the Code of Laws of South Carolina to provide for annual reviews of fuel costs. In the wholesale jurisdiction, fuel costs are reviewed semiannually. All jurisdictions allow Duke Power to adjust rates for past over- or under-recovery of fuel costs. Therefore, Duke Power reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

NP&L's wholesale rates are adjusted annually to reflect current costs. Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

ENERGY MANAGEMENT AND FUTURE POWER NEEDS

The Company's strategy for meeting customers' present and future energy needs consists of three components: supply-side resources, demand-side resources, and purchased power resources. The Company uses a 20 percent planning reserve margin as a baseline to meet contingencies such as forecast uncertainties, unit outages, weather extremes, and historically long lead times for new generation resources. With the increased flexibility from the purchased power market offering short lead time resources and shortened lead times for new generation construction, the Company expects to maintain an operating reserve margin of approximately 17 percent of its anticipated peak load requirements through 2001. The Company continues to engage in a comprehensive energy management program as part of its Integrated Resource Plan (IRP). Integrated resource planning is the process used by utilities to evaluate a variety of resources. The goal is to provide adequate and reliable electricity in an environmentally responsible manner through cost-effective power management. As customers elect to procure generation from other suppliers, as two of the Company's wholesale customers have indicated they will do beginning in 1997, the Company will no longer be obligated to plan for the future generation needs of those customers. The Company files an IRP with the NCUC and the PSCSC once every three years. During each of the intervening years, the Company files a Short Term Action Plan which updates the IRP for any changes in projections for the next three years. The PSCSC issued an order on December 14, 1995 approving the Company's 1995 IRP. On February 20, 1996, the NCUC issued a similar order. Short-term action plans were filed with both the NCUC and the PSCSC in April 1996.

The Company has completed the construction of a combustion turbine facility in Lincoln County, North Carolina, to provide capacity at periods of peak demand. The station consists of sixteen combustion turbines with a total generating capacity of 1,200 megawatts. During 1995, twelve units of the Lincoln Combustion Turbine Station began commercial operation. The last four units began commercial operation in the first quarter of 1996.

Demand-side management (DSM) programs benefit the Company and its customers by providing cost-effective energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing

<PAGE>

strategic sales of electricity. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for DSM programs and allowed the deferral for later recovery of certain DSM costs that exceed the level reflected in rates, including a return on the deferred costs. In 1993, the NCUC and the PSCSC issued orders approving "shared savings"

mechanisms for accomplishments achieved in the Company's DSM programs, and deferral of such shared savings. The May 1996 rate rider in South Carolina included an increment for DSM cost recovery. (See "Rate Matters.") The Company ...mately expects recovery through rates of associated deferred costs, not to ...ceed $75 million including deferred returns in the North Carolina retail jurisdiction. The annual costs deferred, including the return, were approximately $11 million in 1996 and $27 million in 1995. The total costs deferred, including the return, are $67 million and $40 million in North Carolina and South Carolina, respectively.

The purchase of capacity and energy is an integral part of meeting future power needs. As of December 31, 1996, the Company had under contract 329 MW of capacity from other generators of electricity, including 91 MW from qualifying facilities. In 1995, the Company issued two requests for proposals (RFP) to solicit both short-term and long-term competitive bids to provide future electric generating capacity resources. After review of all bids, the Company selected a short-term bid from PECO Energy Co. of Philadelphia. The agreement gives the Company the option to purchase up to 250 megawatts of capacity during the summer months of 1998 through 2001. Contract arrangements between the parties were finalized on August 1, 1996. The long-term RFP was closed and no bids were accepted.

CAPITAL REQUIREMENTS

Projected capital expenditures, excluding costs related to portions of the Catawba Nuclear Station owned by the other Catawba joint owners, for the years set forth below, as now scheduled, are as follows (in millions):

<TABLE>
<CAPTION>

	1997	1998	1999	2000	2001	TOTAL
<S>	<C>	<C>	<C>	<C>	<C>	<C>
...ke Power -- Electric						
Generation	$223	$ 177	$185	$137	$ 142	$ 864
Transmission	38	38	38	38	38	190
Distribution	246	248	251	255	258	1,258
Other	66	59	67	66	58	316
Nuclear Fuel	134	160	130	140	152	716
Total Duke Power -- Electric	707	682	671	636	648	3,344
Associated Enterprises Group	218	318	290	306	382	1,514
Total Company	$925	$1,000	$961	$942	$1,030	$4,858

</TABLE>

The Company's procedures for estimating capital expenditures for Duke Power -- Electric (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs, allowances for inflation and the Company's business plan. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances for Duke Power -- Electric are due to various factors, including revised load estimates, environmental matters and cost and availability of capital. Projections of the AEG capital expenditures are subject to periodic review and revision and may vary significantly as the business plans of the AEG evolve to meet the opportunities presented by their markets.

JOINT OWNERSHIP OF GENERATING FACILITIES

The Company, through several transactions beginning in 1978, sold an 87.5% ...ivided interest in the Catawba Nuclear Station to the other Catawba joint ...ners.

These transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use (whether or not the facility is generating electricity) that portion of the capacity not then contractually required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The transactions also include a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station of the Company, which provides for an exchange of 50 percent of each other Catawba joint owner's retained capacity from its ownership interest in the Catawba units for like amounts of capability and output from units of the McGuire Nuclear Station. The implementation of the reliability exchange has not had, nor does the Company anticipate that such implementation will have, a material effect on earnings. (See Note 3, "Notes to Consolidated Financial Statements.")

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The Company and North Carolina Municipal Power Agency Number 1 (NCMPA) and Piedmont Municipal Power Agency (PMPA), two of the four other joint owners of the Catawba Nuclear Station, entered into a settlement in 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the NCUC on January 16, 1996, and the PSCSC on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on its results of operations or its financial position.

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners, which previously have been approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3, "Notes to the Consolidated Financial Statements.") In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years conform to the settlement agreements, which were approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheet in 1994. Therefore, the Company believes these matters should not have a material adverse effect on its results of operations or its financial position.

FUEL SUPPLY

The Company presently relies principally on nuclear fuel and coal for the

generation of electric energy. The Company's reliance on oil and gas is minimal even with the addition of the Lincoln Combustion Turbine Station, which is designed to operate on either natural gas or oil.

Information regarding the utilization of sources of power and cost of fuels set forth in the following table:

<TABLE>
<CAPTION>

	GENERATION BY SOURCE YEAR ENDED DECEMBER 31			COST OF FUEL PER NET KWH GENERATED (CENTS) YEAR ENDED DECEMBER 31		
	1996	1995	1994	1996	1995	1994
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Coal	54.0%	43.7%	46.9%	1.40	1.56	1.53
Nuclear (1)	44.0	53.7	51.0	0.53	0.57	0.56
Oil and gas (2) (3)	.3	.3	--	6.74	5.06	16.90
All fuels (cost based on weighted average) (1) (2)	98.3	97.7	97.9	1.02	1.03	1.03
Hydroelectric (4)	1.7	2.3	2.1			
	100.0%	100.0%	100.0%			

</TABLE>

(1) Statistics related to nuclear generation and all fuels reflect the Company's 12.5% ownership in the Catawba Nuclear Station.

(2) Statistics related to oil and gas generation and all fuels reflect precommercial generation at the Lincoln Combustion Turbine Station in 1995 and 1996.

(3) Oil and gas cost statistics include amounts for light-off fuel at the Company's coal-fired stations.

(4) Generating figures are net of that output required to replenish pumped storage units during off-peak periods and do not include NP&L.

COAL. The Company obtains a large amount of its coal under long-term supply contracts with mining operators utilizing both underground and surface mining. The Company has on hand an adequate supply of coal. The Company's long-term supply contracts, all of which have price adjustment provisions, have expiration dates ranging from 1997 to 2003. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with

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other coal suppliers for quantities and qualities of coal required. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. The Company's requirements not met by long-term supply contracts have been and will be fulfilled with spot market purchases. The average sulfur content of coal being purchased by the Company is approximately 1 percent. Such coal satisfies the current emission limitation for sulfur dioxide for existing facilities. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- The Clean Air Act Amendments of 1990.")

NUCLEAR. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, enrichment of at gas and fabrication of the enriched uranium hexafluoride into usable fuel emblies. After a region (approximately one-third of the nuclear fuel ssemblies in the reactor at any time) of spent fuel is removed from a nuclear

reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. The Company has contracted for uranium materials and services required to fuel the Oconee, McGuire and Catawba Nuclear Stations. Based upon current projections, these contracts will meet the Company's requirements through the following years:

<TABLE>
<CAPTION>

NUCLEAR STATION	URANIUM MATERIAL	CONVERSION SERVICE	ENRICHMENT SERVICE	FABRICATION SERVICE
<S>	<C>	<C>	<C>	<C>
Oconee	1997	1998	2000	2006
McGuire	1997	1998	2000	2009
Catawba	1997	1998	2000	2009

</TABLE>

Uranium material requirements will be met through various supplier contracts, with uranium material produced primarily in the U.S. and Canada. The Company believes that it will be able to renew contracts as they expire or to enter into similar contractual arrangements with other nuclear fuel materials and services suppliers. Requirements not met by long-term supply contracts have been and will be fulfilled with uranium spot market purchases.

The Department of Energy (DOE) requested Expressions of Interest (EOI) to facilitate in the disposal of plutonium. The Company and Commonwealth Edison, along with the other joint owners of the Catawba Nuclear Station, responded to the EOI in early 1996. As this project is in its early developmental stage, management cannot predict the outcome of this process. However, the Company believes these matters should not have a material effect on the results of operations or financial position of the Company.

The Nuclear Waste Policy Act of 1982 requires that the DOE begin disposing of spent fuel no later than January 31, 1998. The Company has entered into the required contracts with the DOE for the disposal of nuclear fuel and began making payments in July 1983 for disposal costs of fuel currently being utilized. These payments, combined with a one-time payment for disposal costs of fuel consumed prior to April 7, 1983, have totaled about $540 million through 1996 related to the Company's ownership interest in nuclear plants. The DOE has announced that the department anticipates a delay in accepting the waste materials on the contract date of January 31, 1998. The Company has joined with 35 other utilities in a lawsuit attempting to force the DOE to meet its obligations as called for in the contract. While it is uncertain what interim storage will be provided by the DOE due to its inability to meet the contract date, the Company has satisfactory plans in place to provide storage of spent nuclear fuel if the DOE cannot accept it.

REGULATION

The Company is subject to the jurisdiction of the NCUC and the PSCSC which, among other things, must approve the issuance of securities. The Company also is subject, as to some phases of its business, to the jurisdiction of the FERC, the Environmental Protection Agency (EPA) and state environmental agencies and to the jurisdiction of the Nuclear Regulatory Commission (NRC) as to design, construction and operation of its nuclear power facilities. The Company is exempt from regulation as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA), except with respect to the acquisition of the securities of other public utilities.

ENVIRONMENTAL MATTERS. The Company is subject to federal, state, and local regulations with regard to air and water quality, hazardous and solid waste

disposal, and other environmental matters. North Carolina has enacted a declaration of environmental policy requiring all state agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. South Carolina law also requires consideration by the PSCSC of environmental effects in determining whether certificates of public convenience and necessity will be granted

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for proposed major utility facilities, which include certain generation and transmission facilities. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities. In 1996, the Company's construction costs for environmental protection totaled approximately $9 million, while the on-going environmental operation costs were approximately $24 million. The Company's 1997-2001 construction program includes costs for environmental protection which are estimated to be approximately $152 million, including $4.2 million in 1997, $44.5 million in 1998, $55.5 million in 1999, $25.6 million in 2000 and $22.5 million in 2001. These costs include expenditures associated with the Clean Air Act Amendments of 1990. However, governmental regulations establishing environmental protection standards are continually evolving and have not, in some cases, been fully established. These projections are subject to periodic review and revisions. Actual construction costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including cost and availability of capital.

AIR QUALITY. See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- The Clean Air Act Amendments of 1990" for a discussion of the Company's plans for compliance with federal clean air standards. The EPA has recently proposed revisions to two of its air quality standards, one for ozone and the other for particulate matter. These two proposals will not be final until the summer of 1997, and will likely take years to implement fully. The rules as proposed would likely require significant capital expenditures by electric utilities, particularly with respect to coal-fired generation facilities, as well as by businesses in many other industries. If promulgated without revision, it is expected that the rules will be challenged in court, which could delay the effective implementation date or could result in the rules being overturned altogether. Thus, it is too early to estimate with accuracy the impact these rules could have on the Company. Nevertheless, if implemented as proposed, the cost of compliance for the Company could range from approximately $30 million to approximately $600 million over a period currently estimated to be from 2002 through 2005.

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1987 (referred to herein as the "Clean Water Act") require permits for facilities that discharge treated wastewater to the environment. The Company holds numerous such permits, which are issued periodically. The issuance of such permits is delegated by the EPA to state agencies in North and South Carolina. The Clean Water Act has been scheduled for review and reauthorization by Congress since 1994, but no legislation has been enacted. Until Congress acts upon the reauthorization, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

OTHER ENVIRONMENTAL REGULATIONS. Contingencies associated with environmental matters are principally related to possible obligations to remove or mitigate the effects of contaminants resulting from the disposal of certain substances.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as "Superfund," can require any individual or entity which may have owned or operated a disposal site, as well as transporters or generators of hazardous wastes which were sent to such site, to share in remediation costs for the site. Such parties are known as "potentially responsible parties" (PRPs). Some sites are remediated pursuant to state acts which are similar to CERCLA. The Company is currently participating in PRP groups with regard to Superfund sites near Concord, North Carolina and Lenoir, North Carolina. While the total cost of remediation at these federal and state contamination sites may be substantial, the Company shares probable liability with other PRPs, many of which have substantial assets. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

Other clean-up sites in which the Company is involved arise from the former operation of manufactured gas plants (MGP), which were commonplace in the Carolinas until the 1950s. Some such sites are still owned by the Company, and others are now owned by third parties. In North Carolina, the Company is participating in a state-sponsored program to investigate and, where appropriate, remediate MGP sites. In South Carolina, the Company is in the process of remediating an MGP site in Greenville. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

CERCLA has been scheduled for review and reauthorization by Congress since 1994, but no legislation has been enacted. Until CERCLA reform occurs, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

GENERAL. Over the past few decades, the issue of the possible health effects of electric and magnetic fields has generated a number of generally inconclusive studies, some public concern and litigation as well as legislative action in some states regarding high voltage transmission lines. The impact of this issue on the Company cannot presently be determined.

NUCLEAR FACILITIES. The Company's nuclear facilities are subject to continuing regulation by the NRC.

Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company planned for the replacement of steam generators at three units that have experienced SCC and purchased the replacement steam generators from Babcock & Wilcox International. Replacement of the steam generators at Catawba Unit 1 was successfully completed at a lower cost than projected on October 4, 1996, after a 115-day outage that included replacement work and other maintenance. Steam generator replacement in both McGuire units is

scheduled for completion during 1997. The Catawba Unit 2 steam generators have not been scheduled for replacement. Steam generator replacement at each McGuire unit is expected to take approximately four months and cost approximately $170 million, excluding the cost of replacement power. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the other joint owners of the Catawba Station, began a legal action in 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba stations steam generators that were defective in design, workmanship and materials, requiring replacement well short of their stated design life. The lawsuit was settled in 1994. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the Company's results of operations or financial position.

NUCLEAR DECOMMISSIONING COSTS. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5% ownership in the Catawba Nuclear Station. The other Catawba joint owners are responsible for decommissioning costs related to their ownership interests in the station. Such estimates presume each unit will be decommissioned as soon as possible following the end of its license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 -- 2013, Oconee 3 -- 2014; McGuire 1 -- 2021, McGuire 2 -- 2023; and Catawba 1 -- 2024, Catawba 2 -- 2026.

The NRC issued a rulemaking in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1996, the Company expensed approximately $56 million, which was contributed to the external funds and accrued an additional $2 million to the internal reserve. The balance of the external funds as of December 31, 1996, was $363 million. The balance of the internal reserve as of December 31, 1996, was $208 million and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, invested at assumed after-tax earnings rates of 5.5 percent to 5.9 percent, are sufficient to provide for the estimated cost of decommissioning.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid $9.5 million during 1996 and has paid $45.0 million cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of $94.7 million in the Consolidated Balance Sheet at December 31, 1996.

NUCLEAR INSURANCE. For a discussion of the Company's nuclear insurance coverage, see "Note 13, Notes to Consolidated Financial Statements, Commitments and Contingencies -- Nuclear Insurance."

HYDROELECTRIC LICENSES. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven

developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of approximately 805 MW, are licensed for a term expiring in 2008. The Company also holds a license for the Keowee-Toxaway project for a term expiring in 2016, covering the Keowee Hydro Station and the Jocassee Pumped Storage Station for a combined total of approximately 770 MW, on the upper tributaries of the Savannah River in northwestern South Carolina. Additionally, the Company is the licensee through 2027 for the Bad Creek Hydroelectric Station which uses Lake Jocassee as its lower reservoir and has a nameplate rating of 1,065 MW. The Company received new 40-year licenses in 1996 for two existing projects on the Broad River. The Company sold seven small hydroelectric projects in 1996. NP&L holds licenses for 11 hydroelectric projects with a nameplate rating of 100 MW with license terms expiring 2001-2006. The Federal

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Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

INTERCONNECTIONS

The Company has major interconnections and arrangements with its neighboring utilities which it currently considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

COMPETITION

The Company currently is subject to competition in some areas from government-owned power systems, municipally-owned electric systems, rural electric cooperatives and, in certain instances, from other private utilities. Statutes in North Carolina and South Carolina provide for the assignment by the NCUC and the PSCSC, respectively, of all areas outside municipalities in such states to power companies and rural electric cooperatives. Substantially all of the territory comprising the Company's service area has been so assigned. The remaining areas have been designated as unassigned and in such areas the Company remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina there continues to be competition between municipalities and other electric suppliers outside the corporate limits of the municipalities, subject, however, to the regulation of the PSCSC. In addition, the Company is engaged in continuing competition with various natural gas providers.

The Energy Policy Act of 1992 (EPACT) and the FERC's subsequent rulemaking activities are major drivers toward a more competitive market for electric generation. EPACT reformed provisions of PUHCA and Part II of the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, EPACT allows utilities to participate in the development of independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. In addition, EPACT permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that energy suppliers can sell to wholesale customers wherever they are located. It does

not, however, permit the FERC to issue an order requiring transmission access to retail customers.

The FERC, responsible in large measure for implementation of the EPACT, has ›ved vigorously to implement its mandate, interpreting the statute broadly in ›uing orders for third-party transmission service and issuing a number of rules of general applicability. On April 24, 1996, the FERC issued its Order Numbers 888 and 889, which established the final form of transmission tariff to provide comparable service to all users of a utility's transmission system.

Open-access transmission for wholesale customers as defined by the FERC's final rules provides energy suppliers, including the Company, with opportunities to sell and deliver capacity and energy at market-based prices. Engaging in such transactions may result in improved utilization of the Company's existing assets. In addition, such access provides another supply option through which the Company can buy capacity and energy at attractive rates, influencing its competitive price position. However, sales to existing wholesale customers of the Company may continue to be impacted by open access either due to competitive pressure on the wholesale price of electricity, or the potential loss of sales as wholesale customers seek other options to meet their capacity and energy requirements at market-based prices. (For additional information about sales to wholesale customers, see "Liquidity and Resources -- Duke Power Company Rate Matters," and Note 3, "Notes to Consolidated Financial Statements.") Wholesale sales represented approximately 8.8 percent of the Company's total kilowatt-hour sales in 1996. Supplemental sales to the other joint owners of the Catawba Nuclear Station comprised the majority of such sales. Such supplemental sales will continue to decline in 1997 as a result of the retention of larger portions of ownership entitlement by the other joint owners. (For additional information on Catawba joint ownership, see Note 3, "Notes to Consolidated Financial ›tements.")

In early 1995, prior to issuance of the FERC's Notice of Proposed Rulemaking, the Company and certain of its affiliates filed three applications with the FERC, all of which were designed to enable effective participation in the competitive environment of the changing electric utility industry. Duke Power filed an application for permission to sell at market-based rates up to 2,500 megawatts of capacity and energy from its own assets. Two of the Company's affiliates, Duke Energy Marketing Corp. (DEMC) and Duke/Louis Dreyfus LLC (D/LD), filed applications with the FERC to become power marketers. All of the applications were supported by transmission tariffs which complied with then applicable FERC standards and established the rates, terms and conditions for transmission service to third parties on the Company's transmission system. Late in 1995,

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the FERC granted the applications of Duke, DEMC, and D/LD; accepted Duke's transmission tariffs; and ordered a hearing on the rates to be charged for service under those tariffs. On July 9, 1996, in compliance with the standards and schedules set forth in Order Number 888, the Company filed a pro forma open access transmission tariff complying with the requirements of the FERC's final rules. Such a filing was required of all transmission-owning utilities subject to the FERC's jurisdiction. The Company also filed on that date a proposed settlement in the proceeding earlier ordered by the FERC. The proposed ›ttlement resolves all rate issues related to transmission services under ›ke's tariff and contains the rates agreed upon under the settlement. The ›ettlement and the July 9, 1996 tariff filing remain subject to final FERC

approval.

Competition for retail customers is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states regarding retail competition which could result in changes in the industry. Such changes, should they occur, could impact all entities owning generation, including the other joint owners of the Catawba Nuclear Station. The process of assessing changes to the regulatory structure is just beginning in the Company's retail jurisdictions and has not progressed as rapidly as in some other states. A bill was passed in the North Carolina General Assembly to establish a group to study the issues surrounding retail competition. The study group is to report the results of its study to the 1999 General Assembly. While a bill has been introduced to provide for retail competition in South Carolina, the bill does not have the support of all interested parties and in effect just begins the process of addressing the relevant issues in that state. In addition, a bill has been recently introduced in the South Carolina legislature to create an electric deregulation study committee on retail competition. In addition, at the federal level, several bills have been introduced in Congress, and it is likely that other bills will be introduced in the future, that may cover many different issues, including the following: repeal of PUHCA and certain provisions of the Public Utility Regulatory Policies Act of 1978, retail competition, disaggregation of electric utilities and the restructuring of the electric utility industry. This activity is at an early stage, and no assessment of its impact, if any, upon the Company can be made at this time. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- Competition.")

Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry, for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced and utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require affected utilities to write off their associated regulatory assets. The regulatory assets of the Company are classified as "Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

In addition to the changing regulatory environment, another trend toward increasing competition in the electric utility industry is the convergence of markets for electricity and natural gas. The Company's management has noted the emergence of a national market for energy products and services in which demands for energy in the forms of electricity and gas are increasingly being met by vendors who have the ability to supply both. The Company's proposed merger with PanEnergy Corp is its primary strategic response to this trend. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- Proposed Merger with PanEnergy Corp.")

SUBSIDIARIES AND DIVERSIFIED ACTIVITIES

The Company continues to aggressively pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's

shareholders. Among the Company's current industry pursuits are ownership of electric power facilities, energy marketing, real estate, communications, engineering consulting and various energy services. Although these opportunities are primarily concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. The Company undertakes a continuous evaluation of the various lines of business it may enter or exit, with the objective of enhancing shareholder value and managing any associated risk. (See "Subsidiaries and Diversified Activities Highlights.")

Major subsidiaries and diversified activities include the following:

CRESCENT RESOURCES, INC. (Crescent) provides high-quality residential and commercial real estate development services in the Southeast in addition to providing forest management activities focused on growing trees suitable for use in the construction, furniture and paper industries. During 1996, Crescent sold 869 residential developed lots compared to 600 lots in 1995. At December 31, 1996, Crescent owned approximately 2.5 million square feet of office, retail and warehouse space and had approximately 900,000 square feet of commercial properties under construction. Additionally, Crescent had approximately 249,000 acres of land under its management at year end.

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DUKE ENERGY GROUP, INC. (Duke Energy Group) develops, owns, manages and operates energy facilities worldwide. Domestically, Duke Energy Group concentrates on advanced fossil-fueled generation including pulverized coal, circulating fluidized bed, coal gasification and natural gas technologies. Internationally, Duke Energy Group pursues advanced coal-fueled, hydroelectric and gas-fueled generation as well as transmission projects. Duke Energy Group has equity interests in two U.S. electric generation facilities and six international projects.

DUKE ENGINEERING & SERVICES, INC. (DE&S) provides engineering, project management, quality assurance, construction management, operating and maintenance and environmental services for utilities, industry and government worldwide. During 1996, DE&S continued to expand primarily due to the acquisition of the nuclear engineering, government services and power services businesses of VECTRA Technologies, Inc. DE&S was awarded 984 contracts in 1996, including a contract to manage and integrate spent nuclear fuel activities at the Department of Energy's Hanford facility in Washington state. DE&S's domestic and global presence is evident by its 23 U.S. business offices, 13 international offices and projects underway in more than 50 countries.

NANTAHALA POWER AND LIGHT COMPANY (NP&L) is a franchised electric utility which operates 11 hydroelectric plants with a total capacity of 100 megawatts. NP&L has approximately 55,000 customers in western North Carolina. NP&L sold 1,085,000 MWH in 1996 compared with 949,000 MWH in 1995, excluding firm sales and sales to Duke Power.

OTHER BUSINESS UNITS include Church Street Capital Corp., which provides equity funding and credit enhancement services for its subsidiaries and manages investment funds; Duke/Fluor Daniel, a joint venture with Fluor Daniel, Inc., which provides engineering, procurement, construction and operating and maintenance services for fossil-fueled electric generating stations worldwide; Duke/Louis Dreyfus, LLC, which markets electric power, natural gas and energy-related services to utilities, municipalities and other large energy

users in North America; Duke Merchandising, which sells and services home appliances, electronics and wireless communications devices; DukeNet Communications, Inc., which develops and manages communications systems, including fiber optic and wireless digital network services; and Duke Water Operations, which provides franchised water service to customers in parts of North and South Carolina.

EMPLOYEES

At December 31, 1996, the Company had 17,726 full-time employees, which included 2,724 full-time employees of subsidiaries and diversified activities. About 1,850 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW). During the last quarter of 1996, the Company and the IBEW were unable to reach a new labor agreement and, in December 1996, the Company unilaterally implemented its final offer for settlement.

The number of full-time employees has decreased to the 1996 year-end level from 18,551 at year-end 1991. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- Resource Optimization.")

SUBSEQUENT EVENTS

On March 18, 1997, the PSCSC unanimously voted in favor of the merger of the Company and PanEnergy Corp and approved the issuance of securities for the merger. Hearings were held in the PSCSC proceeding on March 6, 1997 and in the NCUC proceeding on March 18, 1997. In connection with the hearings, the Company entered into stipulations with the South Carolina Consumer Advocate and the Public Staff of the NCUC. The stipulations contain certain conditions that, among other things, are generally designed to ensure (i) that the rates of the Company's retail electric and water customers will not be affected by any costs of, or increased costs attributable to, the merger or by any commitments made by the Company in other jurisdictions relating to the merger, (ii) that the Company's future conduct of business with its subsidiaries and affiliates, and its allocation of costs among the Company and its subsidiaries and affiliates, do not lessen competition or adversely impact rates, (iii) that the Company will not seek to increase its retail rates through the year 2000, except to reflect substantial financial impacts of governmental action affecting the industry generally, or a segment thereof, including the Company, or major expenditures attributable to FORCE MAJEURE events, and (iv) that North Carolina's regulatory jurisdiction will not be diminished by preemption, to the detriment of retail customers, should the Company in the future engage in an action that causes it to cease to be exempt from registration under PUHCA. Orders to be issued in both the PSCSC and NCUC proceedings may contain some or all of the conditions set forth in the stipulations.

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DUKE POWER COMPANY
OPERATING STATISTICS

<TABLE>
<CAPTION>

	YEAR ENDED DECEMBER 31,				
	1996	1995	1994	1993	1992
<S>	<C>	<C>	<C>	<C>	<C>
Sources of Electric Energy (a)					
Millions of kilowatt-hours:					
Generated -- net output:					
Coal	40,649	32,389	32,714	34,097	28,999
Nuclear (b)	33,177	39,836	35,587	34,390	33,925
Hydro	1,319	1,685	1,460	1,582	1,834
Oil and gas (c)	199	255	35	43	5
Total generation	75,344	74,165	69,796	70,112	64,763
Purchased power and net interchange	3,587	1,175	1,276	1,750	1,403
Total output	78,931	75,340	71,072	71,862	66,166
Plus: Purchases from other Catawba joint owners	2,662	6,070	9,046	8,810	9,466
Total sources of energy	81,593	81,410	80,118	80,672	75,632
Line loss and company usage	4,741	4,673	4,555	4,614	4,590
Total kilowatt-hour sales	76,852	76,737	75,563	76,058	71,042
Average Cost Per Ton of Coal Burned	$ 36.89	$ 41.72	$ 40.68	$ 42.21	$ 43.47
ectric Energy Sales (a)					
illions of kilowatt-hours:					
Residential	20,992	19,669	18,870	19,465	17,789
General service	19,269	18,160	17,289	16,904	15,818
Industrial					
Textile	11,599	12,151	12,285	11,954	11,685
Other	18,021	17,631	17,005	16,244	15,356
Other energy and wholesale (d)	7,028	8,330	10,274	11,337	10,360
Total kilowatt-hour sales billed	76,909	75,941	75,723	75,904	71,008
Unbilled kilowatt-hour sales	(57)	796	(160)	154	34
Total kilowatt-hour sales	76,852	76,737	75,563	76,058	71,042
Electric Revenue (a)					
Thousands of dollars:					
Residential	$1,519,902	$1,441,362	$1,379,740	$1,424,173	$1,312,227
General service	1,123,804	1,076,791	1,031,061	1,014,124	964,853
Industrial					
Textile	458,844	494,066	498,190	487,576	482,172
Other	765,387	766,750	745,154	726,399	696,413
Other energy and wholesale (d)	379,755	461,367	540,256	476,862	460,849
Other electric revenue	149,181	182,102	84,928	152,742	44,970
Total electric revenues	$4,396,873	$4,422,438	$4,279,329	$4,281,876	$3,961,484
Number of Customers -- end of year (a)					
Residential	1,563,940	1,526,323	1,493,166	1,460,876	1,439,845
General service	253,849	246,276	239,355	232,272	227,675
Industrial					
Textile	1,327	1,390	1,422	1,396	1,390
Other	7,304	7,320	7,320	7,338	7,314

Other energy and wholesale	8,660	8,470	8,187	7,957	7,773
Total customers	1,835,080	1,789,779	1,749,450	1,709,839	1,683,997
Residential Customer Statistics (a)					
Average number for the year	1,549,346	1,514,434	1,483,497	1,455,609	1,431,403
Average annual use -- KWH	13,549	12,988	12,720	13,372	12,427
Average annual billing	$ 981.00	$ 951.75	$ 930.06	$ 978.40	$ 916.74
Average annual billed revenue per KWH (a)					
Cents:					
Residential	7.24	7.33	7.31	7.32	7.38
General service	5.83	5.93	5.96	6.00	6.10
Industrial	4.13	4.23	4.24	4.31	4.36
Other energy and wholesale (d)	5.40	5.54	5.26	4.21	4.45

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(a) Does not include operating statistics of NP&L.

(b) Includes 12.5% of Catawba generation.

(c) 1996 and 1995 include KWH of the Lincoln Combustion Turbine Station prior to commercial operation.

(d) Includes sales to NP&L.

EXECUTIVE OFFICERS OF THE COMPANY

WILLIAM H. GRIGG, 64, Chairman of the Board and Chief Executive Officer. Mr. Grigg served as Chairman of the Board, President and Chief Executive Officer, effective April 28, 1994, until July 27, 1994 when he assumed his present position. He served as Vice Chairman of the Board beginning in 1991, and ecutive Vice President, Customer Group, beginning in 1988.

STEVE C. GRIFFITH, JR., 63, Vice Chairman of the Board and General Counsel. Mr. Griffith served as Executive Vice President and General Counsel from 1991 until he assumed his present position in July 1994. He served as Senior Vice President and General Counsel from 1982 until 1991.

RICHARD B. PRIORY, 50, President and Chief Operating Officer. Mr. Priory served as Executive Vice President, Power Generation Group, from 1991 until he assumed his present position in July 1994. He was Senior Vice President, Generation and Information Services, from 1988 to 1991.

WILLIAM A. COLEY, 53, President, Associated Enterprises Group. Mr. Coley was named Senior Vice President, Power Delivery, in 1988; Senior Vice President, Customer Group, in 1990; and Executive Vice President, Customer Group, in 1991. He was named to his present position in July 1994.

RICHARD J. OSBORNE, 45, Senior Vice President and Chief Financial Officer. Prior to assuming his current position in July 1994, Mr. Osborne served as Vice President and Chief Financial Officer beginning in 1991 and Vice President, Finance, from 1988 to 1991.

JEFFREY L. BOYER, 40, Controller. Mr. Boyer served as Director of Corporate Accounting for more than five years prior to assuming his present position in July 1994.

Executive officers are elected annually by the Board of Directors and serve until the first meeting of the Board of Directors following the next annual meeting of shareholders and until their successors are duly elected.

There are no family relationships between any of the executive officers nor y arrangement or understanding between any executive officer and any other son pursuant to which the officer was selected.

There have been no events under any bankruptcy act, no criminal proceedings

and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

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ITEM 2. PROPERTIES.

At December 31, 1996, the Company, excluding its subsidiary NP&L, operated three nuclear generating stations, eight coal-fired stations and twenty hydroelectric stations, all of which are located in North Carolina or South Carolina.

The following is a list of the major generating stations owned by the Company at December 31, 1996:

<TABLE>
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FACILITY	ENERGY SOURCE	NET MW
<S>	<C>	<C>
Oconee	Nuclear	2,538
McGuire	Nuclear	2,258
Catawba (a)	Nuclear	282
Belews Creek	Coal	2,240
Marshall	Coal	2,090
Allen	Coal	1,140
Cliffside	Coal	760
Others	Coal	1,469
Bad Creek	Hydroelectric	1,065
Jocassee	Hydroelectric	610
Others	Hydroelectric	1,010
ncoln	Oil and gas	1,200
hers	Oil and gas	584

</TABLE>

(a) Represents Duke's 12.5% ownership share in Catawba Nuclear Station.

In addition to the electric generating plants described above, the Company owned, as of December 31, 1996, approximately 8,300 conductor miles of transmission lines, including 600 conductor miles of 500 kilovolts, 1,400 conductor miles of 220 kilovolts, 3,400 conductor miles of 100 kilovolts, and 2,900 conductor miles of 13 to 66 kilovolts. The Company also owned approximately 74,200 conductor miles of distribution lines, including 47,200 conductor miles of rural overhead lines, 14,700 conductor miles of urban overhead lines, 6,900 conductor miles of rural underground lines and 5,400 conductor miles of urban underground lines. As of such date, the Company's transmission and distribution systems comprised approximately 1,600 substations with an installed transformer capacity of approximately 85,200,000 kVA.

NP&L's generation facilities consist of 11 hydroelectric plants with an aggregate nameplate capacity of approximately 100 MW. Duke Power supplies all of NP&L's supplemental power needs from Duke Power's Tuckaseegee Substation near NP&L's Thorpe Plant. NP&L also has an interconnection of 161 kV with the Tennessee Valley Authority (TVA) at Santeetlah, North Carolina. The transmission backbone of the NP&L system is a 161 kV line from Duke's Tuckaseegee Substation to the interconnection with TVA at Santeetlah, with NP&L substations at Robbinsville, Nantahala Plant, Oak Grove, Webster and Thorpe Plant.

The map found at the end of Item 1 shows the locations of the Company's and NP&L's service areas and generating stations.

Substantially all electric plant is mortgaged under the Indenture relating

to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see "Business -- Energy Requirements and Capability."

ITEM 3. LEGAL PROCEEDINGS.

Reference is made to "Business -- Regulation," "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues -- Commitments and Contingencies" and "Note 13, Notes to Consolidated Financial Statements, Commitments and Contingencies -- Other."

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

No matters were submitted to a vote of the Company's security holders during the last quarter of 1996.

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PART II.

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

The Common Stock of the Company is traded on the New York Stock Exchange. At December 31, 1996, there were approximately 130,683 holders of shares of such Common Stock. During 1996, the Company repurchased 3,269,743 shares of its Common Stock, at a total cost of $159 million, through a stock repurchase program. On January 28, 1997, the Board of Directors amended the program to expressly limit the number of shares authorized for repurchase under the program, from the initiation of the program through a date two years after the consummation of the proposed merger with PanEnergy Corp, to an amount not to exceed 15 million shares. (For additional information on the stock repurchase program, see Note 6, "Notes to the Consolidated Financial Statements.")

The following table sets forth for the periods indicated the dividends paid per share of Common Stock and the high and low sales prices of such shares reported by the New York Stock Exchange Composite Transactions:

<TABLE>
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		STOCK PRICE RANGE
COMMON STOCK	DIVIDENDS PER SHARE	HIGH
<S>	<C>	<C>
1996 By Quarter		
Fourth	$0.53	$ 49 1/8
Third	0.53	51 3/8
Second	0.51	51 1/2
First	0.51	53
1995 By Quarter		
Fourth	$0.51	$ 47 7/8
Third	0.51	43 3/4
Second	0.49	42 3/4
First	0.49	40 3/4

<CAPTION>

	STOCK PRICE RANGE
COMMON STOCK	LOW
<S>	<C>
1996 By Quarter	
Fourth	$ 43 3/8

Third	45 3/4
Second	45 3/4
First	46 7/8
95 By Quarter	
ourth	$ 43 1/8
Third	40
Second	38 1/4
First	37 3/8

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ITEM 6.

SELECTED FINANCIAL DATA

<TABLE>
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	1996	1995	1994	1993	1992
<S>	<C>	<C>	<C>	<C>	<C>
Condensed consolidated statements of income (thousands)					
Operating revenues	$ 4,757,974	$ 4,676,684	$ 4,488,913	$ 4,466,233	$ 4,122,503
Operating expenses	3,395,771	3,327,633	3,309,087	3,258,422	3,087,422
Operating income	1,362,203	1,349,051	1,179,826	1,207,811	1,035,081
Interest expense and other income	(156,546)	(168,072)	(143,931)	(171,419)	(223,028)
Income before income taxes	1,205,657	1,180,979	1,035,895	1,036,392	812,053
Income taxes	475,691	466,441	397,019	409,977	303,970
Net income	729,966	714,538	638,876	626,415	508,083
Dividends on preferred and preference stock	44,245	48,903	49,724	52,429	56,407
Earnings for common stock	$ 685,721	$ 665,635	$ 589,152	$ 573,986	$ 451,676
Common stock data					
Shares of common stock					
year-end (thousands)	201,590	204,859	204,859	204,859	204,859
average (thousands)	203,553	204,859	204,859	204,859	204,819
Per share of common stock					
Earnings	$ 3.37	$ 3.25	$ 2.88	$ 2.80	$ 2.21
Dividends	$ 2.08	$ 2.00	$ 1.92	$ 1.84	$ 1.76
Book value -- year-end	$ 24.25	$ 23.36	$ 22.13	$ 21.17	$ 20.26
Market price -- high-low	$ 53-43 3/8	$47 7/8-37 3/8	$ 43-32 7/8	$44 7/8-35 3/8	$37 1/2-31 3/8
-- year-end	$ 46 1/4	$ 47 3/8	$ 38 1/8	$ 42 3/8	$ 36 1/8
Balance sheet data (thousands)					
Total assets	$13,469,690	$13,358,484	$12,862,228	$12,293,605	$11,012,795
Long-term debt	$ 3,538,114	$ 3,711,405	$ 3,567,122	$ 3,285,397	$ 3,288,111
Preferred stock with sinking fund requirements	$ 234,000	$ 234,000	$ 279,500	$ 281,000	$ 279,519

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TEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND NANCIAL CONDITION.

This Management's Discussion and Analysis presents the financial condition,

results of operations and certain forward-looking information about Duke Power Company and its subsidiaries. On November 25, 1996, the Company and PanEnergy Corp announced a proposed stock-for-stock merger. Unless otherwise indicated, information presented herein relates to Duke Power Company only and does not take into account the proposed merger with PanEnergy. (For additional information on the proposed merger, see "Current Issues -- Proposed Merger with PanEnergy Corp.")

RESULTS OF OPERATIONS

EARNINGS AND DIVIDENDS. Earnings per share increased 4 percent from $3.25 in 1995 to $3.37 in 1996. The increase was primarily due to electric customer growth.

Earnings per share increased from $2.88 in 1994 to $3.37 in 1996, indicating an average annual growth rate of 8 percent. Total Company earned return on average common equity was 14.2 percent in 1996 compared to 14.3 percent in 1995 and 13.3 percent in 1994.

The Company continued its practice of annually increasing the common stock dividend. Common dividends per share increased at an average annual rate of 4 percent from $1.92 in 1994 to $2.08 in 1996. Indicated annual dividends per share increased to $2.12.

REVENUES AND SALES. Operating revenues increased at an average annual rate of 3 percent from 1994 to 1996, primarily because of growth in the residential and general service customer classes and increased retail kilowatt-hour sales to weather-sensitive customer classes. As discussed below, increased retail sales were partially offset by decreased sales to wholesale customers. A South Carolina retail rate reduction also decreased revenues in 1996. (For additional information on the South Carolina rate reduction, see "Liquidity and Resources -- Duke Power Company Rate Matters.") Revenues from subsidiaries and diversified operations contributed $162 million to the increase in revenues over the three-year period, primarily from increased engineering service fees and developed lot and land sales.

Wholesale revenues declined in 1996 as a result of the retention of significantly larger portions of ownership entitlement by the other joint owners of the Catawba Nuclear Station. This increased retention reduces the joint owners' supplemental requirements supplied by the Company. The effect on earnings of such wholesale revenue declines is partially offset by declines in purchased power costs from the other joint owners which are not subject to levelization. (For additional information on Catawba joint ownership, see Note 3, "Notes to the Consolidated Financial Statements.")

Kilowatt-hour sales from Duke Power electric operations were flat from 1995 to 1996. Sales to residential, general service, and other industrial customers increased by 7 percent, 6 percent and 2 percent, respectively, as a result of colder winter weather and continued economic growth in Duke Power's service area. However, sales to textile customers decreased 5 percent, due to a weaker demand for textile goods. Wholesale sales decreased 16 percent primarily due to a decrease of 24 percent in supplemental sales requirements to the other joint owners of the Catawba Nuclear Station.

OPERATING EXPENSES. From 1995 to 1996, other operation and maintenance expenses increased 7 percent. Increased activities of subsidiaries and diversified operations contributed to this increase. Distribution maintenance expenses also increased, primarily because of restoration costs associated with a February ice storm and Hurricane Fran.

Other operation and maintenance expenses increased at an average annual rate of 6 percent from 1994 to 1996. Increased activities of the subsidiaries and diversified operations associated with engineering services contributed to

this increase.

Fuel expense increased at an average annual rate of 4 percent from 1994 to 1996. The increase was due primarily to higher system production requirements and higher levels of fossil generation as a percentage of total generation. These increases were partially offset by lower fossil fuel costs.

Net interchange and purchased power expenses decreased from $553 million in 1994 to $379 million in 1996, an average annual decrease of 17 percent. This decrease was primarily the result of lower purchased power costs from the other joint owners not subject to levelization as the other joint owners retained significantly larger portions of their ownership entitlement, and lower levelized costs as a result of the substantial completion of the recovery of such costs from South Carolina customers.

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From 1994 to 1996, depreciation and amortization expense increased at an average annual rate of 3 percent, primarily due to increased depreciation associated with additional investments. These investments were primarily associated with distribution plant, including investment to support customer growth, and the completion of the Lincoln Combustion Turbine Station. (For additional information on the Lincoln Combustion Turbine Station, see "Capital Needs -- Meeting Future Power Needs.")

INTEREST EXPENSE AND OTHER INCOME. Interest expense increased at an average annual rate of 2 percent from 1994 to 1996, primarily due to long-term debt financing activities in 1994.

Allowance for funds used during construction (AFUDC) and other deferred returns, net of associated taxes, represented 11 percent of earnings for common stock in 1996 compared to 13 percent in 1994. AFUDC and other deferred returns are expected to be less than 11 percent of total earnings during the next three years.

The deferred return, net of associated taxes, on the purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station represented 7 percent of earnings for common stock in 1996, 1995 and 1994. The cumulative deferred purchased capacity balance began to decline in 1996 and will continue to decline in 1997. (For additional information on purchased capacity levelization, see "Capital Needs -- Purchased Capacity Levelization.")

AFUDC, net of associated taxes, represented 3 percent of earnings for common stock in 1996 compared to 5 percent in 1995 and 6 percent in 1994. The changes were primarily the result of the construction and subsequent commercial operation of the Lincoln Combustion Turbine Station as 12 units were brought on-line in 1995 and the remaining 4 units were brought on-line during the first quarter of 1996. (For additional information on the Lincoln Combustion Turbine Station, see "Capital Needs -- Meeting Future Power Needs.")

LIQUIDITY AND RESOURCES

DUKE POWER COMPANY RATE MATTERS. Duke Power Company's most recent general rate increase requests in the North Carolina and South Carolina retail jurisdictions were filed and approved in 1991. Additionally, Duke Power has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all of Duke Power's regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

The Public Service Commission of South Carolina (PSCSC), on May 7, 1996,

ordered a rate reduction in the form of a decrement rider of 0.432 cents per kilowatt-hour, or an average of approximately 8 percent, affecting South Carolina retail customers. South Carolina retail sales represent approximately percent of the Company's total retail sales. The rate reduction was reflected bills rendered on or after June 1, 1996. This net decrement rider reflects an interim true-up decrement adjustment associated with the levelization of Catawba Nuclear Station purchased capacity costs and an interim true-up increment associated with amortization of the demand-side management deferral account. The rate adjustment was made because, in the South Carolina retail jurisdiction, cumulative levelized revenues associated with the recovery of Catawba purchased capacity costs had exceeded purchased capacity payments and accrual of deferred returns, and certain demand-side costs had exceeded the level reflected in rates.

Certain of the Company's wholesale customers, excluding the other Catawba joint owners, initiated proceedings in 1995 before the Federal Energy Regulatory Commission (FERC) concerning rate matters. The Company and nine of its eleven wholesale customers entered into a settlement in July 1996 which reduced the customers' rates by approximately 9 percent and renewed their contracts with the Company through the year 2000. Both of the customers that did not enter into the settlement have signed agreements to purchase energy from other suppliers beginning in 1997. The eleven wholesale customers involved in this matter accounted for less than 2 percent of the Company's overall electric revenues during 1996. The two customers that have signed agreements with other suppliers accounted for less than 0.5 percent of the Company's 1996 overall electric revenues. (For additional information about sales to wholesale customers, see "Current Issues -- Competition.")

CATAWBA SETTLEMENTS. The Company and North Carolina Municipal Power Agency mber 1 (NCMPA) and Piedmont Municipal Power Agency (PMPA), two of the four er joint owners of the Catawba Nuclear Station, entered into a settlement in 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the North Carolina Utilities Commission (NCUC) on January 16, 1996, and the PSCSC on January 23, 1996. As part of the settlement, the Company agreed to

purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on its results of operations or its financial position.

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and other Catawba joint owners, which previously have been approved by the mpany's retail regulatory commissions. (For additional information on Catawba int ownership, see Note 3, "Notes to the Consolidated Financial Statements.")

In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years conform to the settlement agreements, which were approved the Company's retail regulatory commissions.

Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on its results of operations or its financial position.

CASH FROM OPERATIONS. Consolidated net cash provided by operating activities in 1996 accounted for 97 percent of total cash from operating, financing and investing activities compared with 81 percent in 1995 and 67 percent in 1994. When 1996 stock repurchase activities are excluded, cash generated from operating activities exceeded the Company's capital needs. (For additional information on the stock repurchase program, see Note 6, "Notes to the Consolidated Financial Statements.")

FINANCING AND INVESTING ACTIVITIES. The Company's consolidated capital structure at year-end 1996, including subsidiary long-term debt, was 54 percent common equity, 39 percent long-term debt and 7 percent preferred stock. This structure is consistent with the Company's target to maintain a double-A credit rating. As of December 31, 1996, Duke Power's bonds were rated "AA" by Fitch Investors Service and Duff & Phelps, "Aa2" by Moody's Investors Service and "AA-" by Standard & Poor's Group. As a result of the announcement of the proposed merger with PanEnergy Corp, the Company has been placed on credit review by the rating agencies. (For additional information on the proposed merger, see "Current Issues -- Proposed Merger with PanEnergy Corp.")

The Company had total credit facilities of $694.9 million and $669.9 million as of December 31, 1996 and 1995, respectively. The Company had unused credit facilities of $474.4 million and $440.6 million as of December 31, 1996 and 1995, respectively.

During July 1996, the Company began purchasing shares of its common stock. The Company has repurchased approximately 3.3 million shares of common stock for $159 million as of December 31, 1996. (For additional information on the stock repurchase program, see Note 6, "Notes to the Consolidated Financial Statements.") In 1995, the Company issued $178 million of long-term debt, of which $72 million was used to retire higher cost long-term debt. The Company also retired $96 million of preferred stock and $80 million of long-term debt in 1995. In 1994, the Company issued $407 million in debt, primarily First and Refunding Mortgage Bonds.

The Company has authority to issue up to $1 billion aggregate principal amount of debt securities under a shelf registration statement filed with the Securities and Exchange Commission (SEC). Such debt securities may be issued as First and Refunding Mortgage Bonds, Senior Notes, or Subordinated Debentures.

In order to obtain variable rate financing at an attractive cost, the Company entered into interest rate swap agreements associated with the November 1994 issuance of $200 million aggregate principal amount of its First and Refunding Mortgage Bonds 8% Series B due 1999 and the August 1995 issuance of $100 million aggregate principal amount of its First and Refunding Mortgage Bonds 7 1/2% Series B due 2025. The interest rate swaps are reset quarterly based upon the three-month London Interbank Offered Rate (LIBOR). As a result of interest rate swap contracts, interest expense is recognized at the weighted average rate for the year tied to the LIBOR rate. The weighted average rates at

December 31, 1996, 1995 and 1994 were 5.64%, 6.14% and 5.95%, respectively, for the 8% Series B due 1999. The weighted average rates at December 31, 1996 and 1995 were 6.69% and 7.06%, respectively, for the 7 1/2% Series B due 2025.

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Duke Energy Group, Inc. entered into a hedge transaction in 1995 to offset currency fluctuations between the U.S. dollar and the Chilean peso associated with expected equity contributions to an affiliate in 1995, 1996 and 1997. The hedge transaction has a notional amount of approximately $4.4 million at December 31, 1996. Duke Energy Group, Inc. records any realized gains or losses associated with the hedge as an adjustment to investments in affiliates.

Duke/Louis Dreyfus (D/LD) enters into various derivative financial instruments involving future settlement. These transactions include exchange-traded futures and options and over-the-counter swaps and options for commodities, primarily natural gas and electricity. D/LD's derivative financial instruments are used for trading and marketing activities. These instruments are accounted for at market value and the related unrealized gains and losses are recognized in income. D/LD utilizes various risk management procedures to monitor its exposure and minimize counterparty risk.

Duke Power's embedded cost of long-term debt, excluding debt of subsidiaries, was 7.95 percent for 1996 compared to 7.94 percent in 1995 and 7.98 percent in 1994. The embedded cost of preferred stock was 6.99 percent in 1996 compared to 7.06 percent in 1995 and 6.99 percent in 1994. The increase in the embedded cost of long-term debt from 1995 to 1996 is primarily the result of maturing lower cost debt. The decrease in the embedded cost of preferred stock from 1995 to 1996 reflects the impact of decreased adjustable dividend rates on certain series of preferred stock.

FIXED CHARGES COVERAGE. Consolidated fixed charges coverage using the SEC method was 5.07 times for 1996 compared to 4.94 and 4.72 times for 1995 and 1994, respectively. The increase is primarily a result of higher earnings. Consolidated fixed charges coverage, excluding AFUDC and other deferred returns, was 4.69 times for 1996 compared with 4.52 for 1995 and 4.32 for 1994 and the Company goal of 3.5 times. The increase in coverage is primarily the result of higher earnings, excluding AFUDC and other deferred returns.

CAPITAL NEEDS

PROPERTY ADDITIONS AND RETIREMENTS. Additions to property and nuclear fuel of $720 million and retirements of $396 million resulted in an increase in gross plant of $324 million in 1996.

Since January 1, 1994, additions to property and nuclear fuel of $4 billion and retirements of $2.5 billion have resulted in an increase in gross plant of $1.5 billion.

CONSTRUCTION EXPENDITURES. Plant construction costs for generating facilities supporting Duke Power electric operations, including AFUDC, decreased from $309 million in 1994 to $164 million in 1996, primarily because of the completion of the Lincoln Combustion Turbine Station. (For more information, see "Capital Needs -- Meeting Future Power Needs.") Construction costs for distribution plant, including AFUDC, increased from $203 million in 1994 to $227 million in 1996.

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including AFUDC, are $2.6 billion and $716 million, respectively, for 1997 through 2001. These construction expenditures are primarily for distribution and production-related activities representing $1.3 billion and $864 million, respectively. These projections are subject to

periodic reviews and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

Projected capital expenditures of subsidiaries and diversified activities are $1.5 billion for 1997 through 2001, of which a significant portion is real estate and power project development. These projections are subject to periodic reviews and revisions and may vary significantly as business plans evolve to meet the opportunities presented by their markets.

For 1997 through 2001, the Company anticipates substantially funding its projected construction and capital expenditures through the internal generation of funds.

PURCHASED CAPACITY LEVELIZATION. The rates established in Duke Power's electric retail jurisdictions permit recovery of its investment in both units of the Catawba Nuclear Station and the costs associated with contractual purchases of capacity from the other joint owners of the Catawba Nuclear Station. The contracts relating to the sales of portions of the station obligate the Company to purchase a declining amount of capacity from the other joint owners. In the North Carolina retail jurisdiction, regulatory treatment of these contracts provides revenue for recovery of the capital costs and the fixed operating and maintenance costs of purchased capacity on a levelized basis. In the South Carolina retail jurisdiction, revenues have been provided for the recovery of the capital costs of purchased capacity on a levelized basis, while current rates include recovery of fixed operating and maintenance expenses.

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Such rate treatments require the Company to fund portions of the purchased capacity payments until these costs, including returns, are recovered at a later date. The Company recovers the accumulated costs and returns when the sum of the declining purchased capacity payments and accrual of returns for the current period drop below the levelized revenues. During 1996, in the North Carolina retail jurisdiction and the wholesale jurisdiction regulated by the Federal Energy Regulatory Commission (FERC), annual levelized revenues exceeded purchased capacity payments and the accrual of deferred returns for the first time. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments and accrual of deferred returns. The PSCSC, on May 7, 1996, ordered a rate reduction in the form of a decrement rider for an interim true-up adjustment. (For additional information on the South Carolina rate reduction, see "Liquidity and Resources -- Duke Power Company Rate Matters.") Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups.

MEETING FUTURE POWER NEEDS. The Company's strategy for meeting customers' present and future energy needs consists of three components: supply-side resources, demand-side resources and purchased power resources. To assist in determining the optimal combination of these three resources, the Company uses an integrated resource planning process. The goal is to provide adequate and reliable electricity in an environmentally responsible, cost-effective manner. As customers elect to procure generation from other suppliers, as two of the Company's wholesale customers have indicated they will do beginning in 1997, the Company will no longer be obligated to plan for the future generation needs of those customers.

The Company has completed the construction of a combustion turbine facility in Lincoln County, North Carolina, to provide capacity at periods of peak

demand. The station consists of 16 combustion turbines with a total generating capacity of 1,200 megawatts. During 1995, twelve units of the Lincoln Combustion Turbine Station began commercial operation. The last four units began commercial operation in the first quarter of 1996.

The purchase of capacity and energy is also an integral part of meeting future power needs. As of January 1, 1997, the Company has 329 megawatts of firm purchased capacity from other generators of electricity under contract, including 91 megawatts from qualifying facilities.

In 1995, the Company issued two requests for proposals (RFP) to solicit both short-term and long-term competitive bids to provide future electric generating capacity resources. After review of all the bids, the Company selected a short-term bid from PECO Energy Co. of Philadelphia. The agreement gives the Company the option to purchase up to 250 megawatts of capacity during the summer months of 1998 through 2001. Contract arrangements between the parties were finalized on August 1, 1996. The long-term RFP was closed and no bids were accepted.

Demand-side management programs benefit the Company and its customers by providing cost-effective energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The May 1996 rate rider in South Carolina included an increment for demand-side management cost recovery. (For additional information on the South Carolina rate rider, see "Liquidity and Resources -- Duke Power Company Rate Matters.") The Company ultimately expects recovery through rates of associated deferred costs, not to exceed $75 million including deferred returns in the North Carolina retail jurisdiction. The annual costs deferred, including the return, were approximately $9 million and $2 million in North Carolina and South Carolina, respectively, in 1996 and $16 million and $11 million in North Carolina and South Carolina, respectively, in 1995. As of December 31, 1996, the balance of deferred demand-side management costs as presented on the Consolidated Balance Sheets in "Other deferred debits" is $67 million and $40 million in North Carolina and South Carolina, respectively.

CURRENT ISSUES

While the Company improved its financial performance in 1996 compared to 1995, its ability to maintain and improve its current level of earnings will depend on several factors. As the electric industry becomes increasingly competitive, the Company's ability to control costs will be an important factor in maintaining a pricing structure that is both attractive to customers and profitable to the Company. Wheeling of third-party energy to a retail customer is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states regarding retail competition which could result in changes in the industry. On April 24, 1996, the FERC issued its final rules on open-access transmission, providing energy suppliers with opportunities to sell and deliver capacity and energy at market-based prices. (For additional information on competition, see "Current Issues -- Competition.") Management cannot predict the outcome of these matters and their impact, if any, on the Company's financial position and results of operation. The

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Company is focusing on providing competitive prices to its industrial customers, as well as to wholesale customers who have access to alternative sources of rgy. Other significant factors impacting the Company's future earnings levels lude continued economic growth in the Piedmont Carolinas, the success of the Company's subsidiaries and diversified activities, and the outcome of various legislative and regulatory actions.

PROPOSED MERGER WITH PANENERGY CORP. On November 25, 1996, the Company and PanEnergy Corp announced a proposed stock-for-stock transaction creating an integrated energy company. Upon consummation of the merger, PanEnergy will be a wholly owned subsidiary of the Company, and the Company's name will be changed to Duke Energy Corporation. The transaction is expected to close by December 31, 1997, subject to approval of the shareholders of both companies and all applicable regulatory approvals. The shareholders of each company will vote on the proposed merger at their annual meetings, which are scheduled for April 24, 1997 for both companies. Applications for regulatory approval were filed with the NCUC and the PSCSC on December 19, 1996, and with the FERC on February 3, 1997. Regulatory proceedings are expected to be successfully completed by year-end 1997. In connection with the transaction, each share of PanEnergy common stock will be converted into 1.0444 shares of common stock of the Company. The transaction will be accounted for as a pooling of interests. Further details about the proposed acquisition are provided in the Company's report on Form 8-K, filed with the Securities and Exchange Commission on December 9, 1996, and in the Joint Proxy Statement-Prospectus provided to shareholders in connection with the Company's annual meeting. Unless otherwise indicated, all information presented herein relates to the Company only and does not take into account the proposed merger with PanEnergy.

RESOURCE OPTIMIZATION. The Company has been engaged in a concentrated ort to more efficiently and effectively use its resources through better work practices. In 1995, the Company offered to certain employees an Enhanced Vested Benefits program (EVB) which gave targeted employees, who left the Company, an enhanced vested retirement package and the Company's standard severance pay based on years of service. This program resulted in the elimination of approximately 900 positions during 1996. During 1994, the Company offered an Enhanced Voluntary Separation program (EVS) which gave most employees the option of leaving the Company for a lump-sum payment and the Company's standard severance pay based on years of service. This program resulted in the departure of approximately 1,300 employees in 1994. Implementing various efficiency practices has resulted in streamlined work flows and provided the opportunity for work force reduction programs such as EVB and EVS.

FULL-TIME EMPLOYEES

<TABLE>
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	1996	1991
<S>	<C>	<C>
Duke Power electric operations	15,002	18,187
Subsidiaries and diversified businesses	2,724	364
Total	17,726	18,551

</TABLE>

The increase in workforce of subsidiaries and diversified businesses is mmensurate with the growth in their business opportunities.

NUCLEAR DECOMMISSIONING COSTS. Estimated site-specific nuclear commissioning costs, including the cost of decommissioning plant components

not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Such estimates presume each unit will be decommissioned as soon as possible following the end of its license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 -- 2013, Oconee 3 -- 2014; McGuire 1 -- 2021, McGuire 2 -- 2023; and Catawba 1 -- 2024, Catawba 2 -- 2026.

In accordance with a 1988 Nuclear Regulatory Commission order, during 1996, the Company expensed approximately $56 million which was contributed to the external funds and accrued an additional $2 million to the internal reserve. The balance of the external funds as of December 31, 1996, was $363 million. The balance of the internal reserve as of December 31, 1996, was $208 million and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets.

Both the NCUC and the PSCSC have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Decommissioning costs being recovered

through rates, invested at assumed after-tax earnings rate of 5.5 percent to 5.9 percent, are sufficient to provide for the estimated cost of decommissioning.

As required under the Nuclear Waste Policy Act of 1982, the Company entered into a contract with the U.S. Department of Energy (DOE) under which the DOE agreed to dispose of the Company's spent nuclear fuel. The DOE has announced that the department anticipates a delay in accepting the waste materials on the contract date of January 31, 1998. The Company has joined with 35 other utilities in a lawsuit attempting to force the DOE to meet its obligations as called for in the contract. While it is uncertain what interim storage will be provided by the DOE due to its inability to meet the contract date, the Company has satisfactory plans in place to provide storage of spent nuclear fuel if the DOE cannot accept it.

ENVIRONMENTAL ISSUES. The Company is subject to federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal, and other environmental matters. The Company was an operator of manufactured gas plants until the early 1950s. The Company has entered into a cooperative effort with the State of North Carolina and other owners of certain former manufactured gas plant sites to investigate and, where necessary, remediate these contaminated sites. The State of South Carolina has expressed interest in entering into a similar arrangement. The Company is considered by regulators to be a potentially responsible party and may be subject to liability at four federal Superfund sites. While the cost of remediation of these sites may be substantial, the Company will share in any liability associated with remediation of contamination at such sites with other potentially responsible parties. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

THE CLEAN AIR ACT AMENDMENTS OF 1990. The Clean Air Act Amendments of 1990 require a two-phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national

objective of clean air in the most cost-effective manner and has already reduced emissions through the use of low-sulfur coal in its fossil plants, efficient plant operations and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. To meet the Phase II requirements by 2000, the Company's current strategy includes the use of lower sulfur coal, emission allowance purchases, low nitrogen oxide burners and emission monitoring equipment. A one-time cost associated with bringing the Company into compliance with the Act could range from $94 million to $260 million. Additional operating expenses of approximately $25 million will be incurred for fuel premiums and emission allowance purchases each year after 2000. This strategy is contingent upon developments in the emissions allowance market, lower sulfur coal premiums, future regulatory and legislative actions, and advances in clean air technology.

STRESS CORROSION CRACKING. Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company planned for the replacement of steam generators at three units that have experienced SCC and purchased the replacement steam generators from Babcock & Wilcox International. Replacement of the steam generators at Catawba Unit 1 was successfully completed at a lower cost than projected on October 4, 1996, after a 115-day outage that included replacement work and other maintenance. Steam generator replacement in both McGuire units is scheduled for completion during 1997. The Catawba Unit 2 steam generators have not been scheduled for replacement. Steam generator replacement at each McGuire unit is expected to take approximately four months and cost approximately $170 million, excluding the cost of replacement power. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the other joint owners of the Catawba Station, began a legal action in 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba stations steam generators that were defective in design, workmanship and materials, requiring replacement well short of their stated design life. The lawsuit was settled in 1994. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the Company's results of operations or financial position.

COMPETITION. The Energy Policy Act of 1992 (EPACT) and the FERC's subsequent rulemaking activities are major drivers towards a more competitive market for electric generation. EPACT reformed provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, EPACT allows utilities to participate in the development of independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally,

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without becoming subject to regulation under PUHCA as an electric utility

holding company. In addition, EPACT permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that energy suppliers can sell to wholesale customers wherever they are located. It does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

The FERC, responsible in large measure for implementation of the EPACT, has moved vigorously to implement its mandate, interpreting the statute broadly in issuing orders for third-party transmission service and issuing a number of rules of general applicability. On April 24, 1996, the FERC issued its Order Numbers 888 and 889, which established the final form of transmission tariff to provide comparable service to all users of a utility's transmission system.

Open-access transmission for wholesale customers as defined by the FERC's final rules provides energy suppliers, including the Company, with opportunities to sell and deliver capacity and energy at market-based prices. Engaging in such transactions may result in improved utilization of the Company's existing assets. In addition, such access provides another supply option through which the Company can buy capacity and energy at attractive rates, influencing its competitive price position. However, sales to existing wholesale customers of the Company may continue to be impacted by open access either due to competitive pressure on the wholesale price of electricity, or the potential loss of sales as wholesale customers seek other options to meet their capacity and energy requirements at market-based prices. (For additional information about sales to wholesale customers, see "Liquidity and Resources -- Duke Power Company Rate Matters," and Note 3, "Notes to Consolidated Financial Statements.") Wholesale sales represented approximately 8.8 percent of the Company's total kilowatt-hour sales in 1996. Supplemental sales to the other joint owners of the Catawba Nuclear Station comprised the majority of such sales. Such supplemental sales will continue to decline in 1997 as a result of the retention of larger portions of ownership entitlement by the other joint owners. (For additional information on Catawba joint ownership, see Note 3, "Notes to the Consolidated Financial Statements.")

In early 1995, prior to issuance of the FERC's Notice of Proposed Rulemaking, the Company and certain of its affiliates filed three applications with the FERC, all of which were designed to enable effective participation in the competitive environment of the changing electric utility industry. Duke Power filed an application for permission to sell at market-based rates up to 2,500 megawatts of capacity and energy from its own assets. Two of the Company's affiliates, Duke Energy Marketing Corp. (DEMC) and Duke/Louis Dreyfus L.L.C. (D/LD), filed applications with the FERC to become power marketers. All of the applications were supported by transmission tariffs which complied with then-applicable FERC standards and established the rates, terms and conditions for transmission service to third parties on the Company's transmission system. Late in 1995, the FERC granted the applications of Duke, DEMC, and D/LD; accepted Duke's transmission tariffs; and ordered a hearing on the rates to be charged for service under those tariffs. On July 9, 1996, in compliance with the standards and schedules set forth in Order Number 888, the Company filed a pro forma open access transmission tariff complying with the requirements of the FERC's final rules. Such a filing was required of all transmission-owning utilities subject to the FERC's jurisdiction. The Company also filed on that date a proposed settlement in the proceeding earlier ordered by the FERC. The proposed settlement resolves all rate issues related to transmission services under Duke's tariff and contains the rates agreed upon under the settlement. The settlement and the July 9, 1996 tariff filing remain subject to final FERC approval.

Competition for retail customers is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states, including North and South Carolina, regarding retail competition which could result in changes in the industry. Such changes, should they occur, could impact all entities owning generation, including the other joint owners of the Catawba Nuclear Station.

Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry, for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced and utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require affected utilities to write off their associated regulatory assets. The regulatory assets of the Company are classified as "Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

COMMITMENTS AND CONTINGENCIES. The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which may involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," in order to provide for such matters. Management

is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

SUBSIDIARIES AND DIVERSIFIED OPERATIONS. The Company continues to aggressively pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Among the Company's current industry pursuits are ownership of electric power facilities, energy marketing, real estate, communications, engineering consulting and various energy services. Although these opportunities are primarily concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. The Company undertakes a continuous evaluation of the various lines of business it may enter or exit, with the objective of enhancing shareholder value and managing any associated risk.

Domestically, non-electric property of the Company's subsidiaries and diversified activities was $404 million and $335 million at December 31, 1996 and 1995, respectively. The Company had equity investments in affiliates, which own assets within the United States, of $82 million and $58 million at December 31, 1996 and 1995, respectively.

Internationally, the Company had equity investments in affiliates, which own generation and transmission facilities, of $107 million and $105 million at December 31, 1996 and 1995, respectively. Additionally, the Company, through its

non-regulated subsidiaries, had loaned $3 million and $23 million to certain of these affiliates at December 31, 1996 and 1995, respectively.

The Company's subsidiaries and diversified activities contributed $51 lion to net income in 1996 compared with $54 million in 1995 and $52 million 1994. From 1994 to 1996, increased developed lot and land sales, and engineering services and construction fees generated additional income. These increases were offset by personal communications services joint venture start-up losses and a provision for an investment in a plant in Argentina.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

DUKE POWER COMPANY

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CONSOLIDATED STATEMENTS OF INCOME

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	YEAR ENDED DECEMBER 31,		
	1996	1995	1994
<S>	<C>	<C>	<C>
	DOLLARS IN THOUSANDS		
Operating Revenues (Notes 1, 2 and 11)	$4,757,974	$4,676,684	$4,488,913
Operating Expenses			
Fuel used in electric generation (Note 1)	758,498	744,226	705,019
Net interchange and purchased power (Notes 2 and 3)	378,724	468,293	553,355
Other operation and maintenance	1,505,028	1,403,547	1,341,659
Depreciation and amortization (Note 1)	492,185	458,131	459,781
General taxes	261,336	253,436	249,273
Total operating expenses	3,395,771	3,327,633	3,309,087
perating Income	1,362,203	1,349,051	1,179,826
erest Expense and Other Income (Note 1)			
nterest expense	(283,075)	(289,318)	(270,217)

Allowance for funds used during construction and other deferred returns	111,891	125,040	111,872
Other, net	14,638	(3,794)	14,414
Total interest expense and other income	(156,546)	(168,072)	(143,931)
;ome Before Income Taxes	1,205,657	1,180,979	1,035,895
;ome Taxes (Notes 1 and 4)	475,691	466,441	397,019
Net Income	729,966	714,538	638,876
Dividends on preferred and preference stock	44,245	48,903	49,724
Earnings for Common Stock	$ 685,721	$ 665,635	$ 589,152
Common Stock Data (Note 6)			
Average shares outstanding (thousands)	203,553	204,859	204,859
Earnings per share	$ 3.37	$ 3.25	$ 2.88
Dividends per share	$ 2.08	$ 2.00	$ 1.92

</TABLE>

See notes to consolidated financial statements.

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CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

<TABLE>
<CAPTION>

	YEAR ENDED DECEMBER 31,		
	1996	1995	1994
<S>	<C>	<C>	<C>
	DOLLARS IN THOUSANDS		
Balance -- Beginning of year	$2,858,275	$2,605,920	$2,410,825
Add -- Net income	729,966	714,538	638,876
Total	3,588,241	3,320,458	3,049,701
;educt			
Dividends			
Common stock	423,064	409,716	393,370
Preferred and preference stock	44,245	48,903	49,724
Capital stock transactions, net	128,358	3,564	687
Total deductions	595,667	462,183	443,781
Balance -- End of year	$2,992,574	$2,858,275	$2,605,920

</TABLE>

See notes to consolidated financial statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

<TABLE>
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	YEAR ENDED DECEMBER 31,		
	1996	1995	1994
<S>	<C>	<C>	<C>
	DOLLARS IN THOUSANDS		
Cash Flows from Operating Activities			
Net Income	$ 729,966	$ 714,538	$ 638,876
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash items			
Depreciation and amortization	667,713	674,816	647,515
Deferred income taxes and investment tax credit amortization	(27,641)	5,989	94,261

</TABLE>

Allowance for equity funds used during construction	(15,824)	(23,082)	(27,411)
Purchased capacity levelization	73,473	(33,149)	(268,925)
Other, net	47,384	76,029	22,460
(Increase) Decrease in			
Accounts receivable	(20,289)	(136,838)	47,586
Inventory	40,476	(14,549)	(28,568)
Prepayments	(1,031)	(7,178)	(435)
Increase (Decrease) in			
Accounts payable	15,153	11,694	(52,506)
Taxes accrued	(19,750)	14,454	(51,641)
Interest accrued and other liabilities	(6,966)	28,934	14,523
Total adjustments	752,698	597,120	396,859
Net cash provided by operating activities	1,482,664	1,311,658	1,035,735
Cash Flows from Investing Activities			
Construction expenditures and other property additions	(646,465)	(713,299)	(772,452)
Investment in nuclear fuel	(84,206)	(76,603)	(108,711)
External funding for decommissioning	(56,470)	(56,470)	(52,524)
Pre-funded pension cost	--	--	(30,000)
Investment in affiliates	(25,708)	(54,945)	(6,718)
Net change in investment securities	(25,887)	54,425	17,922
Net cash used in investing activities	(838,736)	(846,892)	(952,483)
Cash Flows from Financing Activities			
Proceeds from the issuance of			
First and refunding mortgage bonds	--	173,839	343,824
Short-term notes payable, net	(49,750)	48,200	86,300
Construction loans and other	113,997	47,643	57,032
Payments for the redemption of			
First and refunding mortgage bonds	(3,097)	(157,365)	(81,781)
Common stock	(159,000)	--	--
Construction loans and other	(91,548)	(9,416)	(18,885)
Preferred stock	--	(100,516)	(1,500)
Dividends paid	(466,751)	(458,018)	(443,633)
Other	2,917	(1,153)	(20,991)
Net cash used in financing activities	(653,232)	(456,786)	(79,634)
Net increase (decrease) in cash	(9,304)	7,980	3,618
Cash at beginning of year	45,410	37,430	33,812
Cash at End of Year	$ 36,106	$ 45,410	$ 37,430

</TABLE>

See notes to consolidated financial statements.

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CONSOLIDATED BALANCE SHEETS

<TABLE>
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	YEAR ENDED DECEMBER 31,	
	1996	1995
<S>	<C>	<C>
	Dollars in Thousands	
ASSETS		
urrent Assets		
ash (Notes 5 and 10)	$ 36,106	$ 45,410
hort-term investments (Notes 1 and 10)	72,712	76,300

Receivables (less allowance for losses: 1996 -- $7,134; 1995 -- $6,352) (Note 1)	709,992	689,703
Inventory -- at average cost	301,365	341,841
Prepayments and other	23,931	22,900
Total current assets	1,144,106	1,176,154
Investments and Other Assets		
Investments in affiliates (Note 11)	188,982	163,274
Other investments, at cost or less (Note 10)	114,669	85,194
Nuclear decommissioning trust funds (Notes 10 and 14)	362,627	273,466
Pre-funded pension cost (Note 12)	80,000	80,000
Total investments and other assets	746,278	601,934
Property, Plant and Equipment (Notes 1, 3, 9, 13 and 14)		
Electric plant in service (at original cost)		
Production	7,278,439	7,154,332
Transmission	1,543,688	1,532,302
Distribution	4,303,885	4,105,513
Other	1,068,342	1,030,226
Electric plant in service	14,194,354	13,822,373
Less accumulated depreciation and amortization	5,438,498	5,122,192
Electric plant in service, net	8,755,856	8,700,181
Nuclear fuel	604,813	731,691
Less accumulated amortization	363,290	453,921
Nuclear fuel, net	241,523	277,770
Construction work in progress (including nuclear fuel in process: 1996 -- $27,546; 1995 -- $25,500)	388,999	382,582
Total electric plant, net	9,386,378	9,360,533
Other property -- at cost (less accumulated depreciation: 1996 -- $31,544; 1995 -- $29,956)	426,039	354,713
Total property, plant and equipment, net	9,812,417	9,715,246
Deferred Debits (Notes 1, 3, 4 and 13)		
Purchased capacity costs	892,000	965,473
Debt expense	169,842	180,930
Regulatory asset related to income taxes	488,936	490,676
Regulatory asset related to DOE assessment fee	94,717	101,274
Other	121,394	126,797
Total deferred debits	1,766,889	1,865,150
Total Assets	$13,469,690	$13,358,484
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 327,315	$ 343,692
Notes payable (Notes 5 and 10)	105,550	155,300
Taxes accrued (Note 1)	973	34,884
Interest accrued	64,589	73,675
Current maturities of long-term debt (Note 9)	212,309	12,071
Other (Note 13)	152,233	149,555
Total current liabilities	862,969	769,177
Long-Term Debt (Notes 5, 9 and 10)	3,538,114	3,711,405
Accumulated Deferred Income Taxes (Notes 1 and 4)	2,376,012	2,382,204
Deferred Credits and Other Liabilities		
Investment tax credit (Notes 1 and 4)	250,117	261,347
DOE assessment fee (Note 1)	94,717	101,274
Nuclear decommissioning costs externally funded (Note 14)	362,627	273,466
Other	412,419	390,427
Total deferred credits and other liabilities	1,119,880	1,026,514
Preferred and Preference Stock with Sinking Fund Requirements (Notes 8 and 10)		234,000

234,000		
Preferred and Preference Stock without Sinking Fund Requirements (Notes 7 and 10)	450,000	450,000
nmitments and Contingencies (Notes 11 and 13)		
ommon Stockholders' Equity (Note 6)		
Common stock, no par, 300,000,000 shares authorized; 201,589,596 shares outstanding for 1996 and 204,859,339 shares outstanding for 1995	1,896,141	1,926,909
Retained earnings	2,992,574	2,858,275
Total common stockholders' equity	4,888,715	4,785,184
Total Liabilities and Stockholders' Equity	$13,469,690	$13,358,484

</TABLE>

See notes to consolidated financial statements.

<PAGE>

DUKE POWER COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. NATURE OF OPERATIONS

The Company is primarily engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas. The Company is one of the nation's largest investor-owned electric utilities.

The Company is also engaged in a variety of diversified operations, most of which are organized in separate subsidiaries. The Company's subsidiaries and diversified activities are in the Associated Enterprises Group (AEG). AEG includes Church Street Capital Corp.; Crescent Resources, Inc.; Duke Energy Group, Inc.; Duke Engineering & Services, Inc.; Duke/Fluor Daniel; Duke/Louis Dreyfus, LLC; Duke Merchandising; DukeNet Communications, Inc.; Duke Water Operations; and Nantahala Power and Light Company. Certain subsidiaries have invested in both domestic and international affiliates. (See Note 11.)

The financial statements are prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions which should be included. In preparing these statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported. However, actual results could differ from these estimates.

B. REVENUES

Electric revenues are recorded as service is rendered to customers. "Receivables" on the Consolidated Balance Sheets include $205,656,000 and $206,792,000 as of December 31, 1996 and 1995, respectively, for electric service that has been rendered but not yet billed to customers by Duke Power, and $4,294,000 as of December 31, 1996 for electric service that has been rendered but not yet billed to customers by Nantahala Power and Light Company.

C. ADDITIONS TO ELECTRIC PLANT

The Company capitalizes all construction-related direct labor and materials as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of money (allowance for funds used during nstruction). The cost of renewals and betterments of units of property is pitalized.

The cost of repairs and replacements representing less than a unit of

property is charged to electric expenses. The original cost of property retired, together with removal costs less salvage value, is charged to accumulated depreciation.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

AFUDC represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities. AFUDC, a non-cash item, is recognized as a cost of "Construction work in progress," with an offsetting credit to "Interest expense and other income." After construction is completed, the Company is permitted to recover these construction costs, including a fair return, through their inclusion in rate base and in the provision for depreciation.

The AFUDC rates of 9.7, 9.3 and 9.6 percent for Duke Power for 1996, 1995 and 1994, respectively, include a component for debt cost on a pre-tax basis. Rates for all periods are compounded semiannually.

E. OTHER DEFERRED RETURNS

Other deferred returns represent the estimated financing costs associated with funding certain regulatory assets. These regulatory assets primarily arise from the Company's funding of purchased capacity costs above levels collected in rates. Other deferred returns are non-cash items. They are primarily recognized as an addition to "Purchased capacity costs" and as an offsetting credit to "Interest expense and other income."

F. DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT

Provisions for electric plant depreciation are recorded using the straight-line method. The year-end composite weighted-average depreciation rates were 3.44, 3.48 and 3.46 percent for 1996, 1995 and 1994, respectively.

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES -- Continued

Amortization of nuclear fuel is included in "Fuel used in electric generation" in the Consolidated Statements of Income. The amortization is recorded using the units-of-production method.

Under provisions of the Nuclear Waste Policy Act of 1982, the Company has entered into contracts with the Department of Energy (DOE) for the disposal of spent nuclear fuel. Payments made to the DOE for disposal costs are based on nuclear output and are included in "Fuel used in electric generation" in the Consolidated Statements of Income.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid $9,472,000 during 1996 and has paid $45,022,000 cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of $94,717,000 in the Consolidated Balance Sheet at December 31, 1996.

G. SUBSIDIARIES

The Company's consolidated financial statements reflect consolidation of all of its majority-owned subsidiaries. Intercompany transactions have been minated in consolidation.

INCOME TAXES

The Company and its subsidiaries file a consolidated federal income tax

return.

Deferred income taxes have been provided for temporary differences. Temporary differences occur when events and transactions recognized for ancial reporting result in taxable or tax-deductible amounts in different riods. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

I. UNAMORTIZED DEBT PREMIUM, DISCOUNT AND EXPENSE

Expenses incurred in connection with the issuance of presently outstanding long-term debt issued for regulated operations, and premiums and discounts relating to such debt, are being amortized over the terms of the respective issues. Also, any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations used to finance regulated assets and operations are being amortized over the lives of the new issues of long-term debt.

J. CONSOLIDATED STATEMENTS OF CASH FLOWS

For purposes of the Consolidated Statements of Cash Flows, the Company's short-term investments in highly liquid debt instruments, with an original maturity of three months or less, are included in cash flows from investing activities and thus are not considered cash equivalents.

Total income taxes paid were $491,340,000, $441,440,000 and $372,416,000 for the years ended December 31, 1996, 1995 and 1994, respectively.

Interest paid, net of amounts capitalized, was $269,219,000, $258,698,000 and $236,696,000 for the years ended December 31, 1996, 1995 and 1994, respectively.

K. COST-BASED REGULATION

As a regulated entity, the Company is subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Accordingly, e Company records certain assets and liabilities that result from the effects the ratemaking process that would not be recorded under generally accepted accounting principles for non-regulated entities. Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced, and utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require affected utilities to write off their associated regulatory assets. The regulatory assets of the Company are classified as

<PAGE>

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES -- Continued

"Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

OTE 2. RATE MATTERS

)UKE POWER COMPANY

The North Carolina Utilities Commission (NCUC) and The Public Service

Commission of South Carolina (PSCSC) must approve rates for retail sales within their respective states. The Federal Energy Regulatory Commission (FERC) must approve Duke Power's rates for sales to wholesale customers. Sales to the other joint owners of the Catawba Nuclear Station, which represent a substantial majority of Duke Power's wholesale revenues, are set through contractual agreements. (See Note 3.)

The most recent general rate increase requests in Duke Power's retail jurisdictions were filed and approved in 1991. Duke Power also filed its most recent general rate increase request within the FERC wholesale jurisdiction in 1991. A negotiated settlement between Duke Power and the wholesale customers was approved by the FERC in 1992.

Fuel costs are reviewed semiannually in the wholesale jurisdiction and annually in the South Carolina retail jurisdiction, with provisions for changing such costs in base rates. In the North Carolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings.

All jurisdictions allow Duke Power to adjust rates for past over- or under-recovery of fuel costs. Therefore, Duke Power reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

The PSCSC, on May 7, 1996, ordered a rate reduction in the form of a decrement rider of 0.432 cents per kilowatt-hour, or an average of approximately 8 percent, affecting South Carolina retail customers. South Carolina retail sales represent approximately 30 percent of the Company's total retail sales. The rate reduction was reflected on bills rendered on or after June 1, 1996. This net decrement rider reflects an interim true-up decrement adjustment associated with the levelization of Catawba Nuclear Station purchased capacity costs and an interim true-up increment associated with amortization of the demand-side management deferral account. The rate adjustment was made because, in the South Carolina retail jurisdiction, cumulative levelized revenues associated with the recovery of Catawba purchased capacity costs had exceeded purchased capacity payments and accrual of deferred returns, and certain demand-side costs had exceeded the level reflected in rates.

Certain of the Company's wholesale customers, excluding the other Catawba joint owners, initiated proceedings in 1995 before the FERC concerning rate matters. The Company and nine of its eleven wholesale customers entered into a settlement in July 1996 which reduced the customers' rates by approximately 9 percent and renewed their contracts with the Company through the year 2000. Both of the customers that did not enter into the settlement have signed agreements to purchase energy from other suppliers beginning in 1997. The eleven wholesale customers involved in this matter accounted for less than 2 percent of the Company's overall electric revenues during 1996. The two customers that have signed agreements with other suppliers accounted for less than 0.5 percent of the Company's 1996 overall electric revenues.

NANTAHALA POWER AND LIGHT COMPANY

During 1996, Nantahala Power and Light Company (NP&L) filed an application with and received approval from the NCUC to increase its annual retail service revenues by $4.6 million. NP&L's wholesale rates are adjusted annually to reflect current costs. Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

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DUKE POWER COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- CONTINUED

OTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES

The Company previously sold interests in both units of the Catawba Nuclear Station. The other owners of portions of the Catawba Nuclear Station and supplemental information regarding their ownership are as follows:

<TABLE>
<CAPTION>

OWNER	OWNERSHIP INTEREST IN THE STATION
<S>	<C>
North Carolina Municipal Power Agency Number 1 (NCMPA).....	37.5%
North Carolina Electric Membership Corporation (NCEMC).....	28.125%
Piedmont Municipal Power Agency (PMPA).....	12.5%
Saluda River Electric Cooperative, Inc. (Saluda River).....	9.375%

</TABLE>

Each owner has provided its own financing for its ownership interest in the station.

The Company retains a 12.5 percent ownership interest in the Catawba Nuclear Station. As of December 31, 1996, $497,304,000 of "Electric plant in service" and "Nuclear fuel" represents the Company's investment in Units 1 and 2. Accumulated depreciation and amortization of $192,057,000 associated with Catawba has been recorded as of year-end. The Company's share of operating costs of Catawba is included in the Consolidated Statements of Income.

In connection with the joint ownership, the Company has entered into ntractual agreements with the other joint owners to purchase declining percentages of the generating capacity and energy from the plant. These purchased power agreements were effective beginning with the commercial operation of each unit. Unit 1 and Unit 2 began commercial operation in June 1985 and August 1986, respectively. The purchased power agreements were established for 15 years for NCMPA and PMPA and 10 years for NCEMC and Saluda River. While the purchased power agreements with NCMPA and PMPA extend for 15 years, a significant decrease in the percentage of capacity and energy the Company is obligated to purchase occurs in the 11th calendar year of operation for each unit. This significant decrease occurred in 1995 for Unit 1 and 1996 for Unit 2.

The agreements also provide for supplemental power sales by the Company to the other joint owners. Such power sales are to satisfy capacity and energy needs of the other joint owners beyond the capacity and energy which they retain from Catawba or potentially acquire in the form of other resources. The agreements further provide the other joint owners the ability to secure such supplemental requirements outside of these contractual agreements following an appropriate notice period. NCEMC and Saluda River have given appropriate notice that they intend to acquire their supplemental capacity requirements outside of these agreements effective January 1, 2001 and January 1, 2002, respectively, thus relieving the Company of the obligation to serve this portion of load. As the joint owners retain more capacity and energy from Catawba, or a third party, supplemental power sales are expected to decline.

The agreements with each of the other joint owners include provisions that Company will provide generating reserves to backstand the other joint wners' retained capacity in the Catawba plant at the system average cost of

installed capacity. Additionally, the agreements include certain reliability exchanges designed to manage outage-related risks by exchanging energy ·itlements between the Catawba Nuclear Station and the McGuire Nuclear .tion, impacting the Company as well as all the other joint owners.

<PAGE>

DUKE POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- CONTINUED

NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES -- Continued

Purchased energy cost payments are based on variable operating costs and are a function of the generation output of Catawba. Purchased capacity payments are based on the fixed costs of the plant and include the capital costs and fixed operating and maintenance costs. Actual purchased capacity costs for 1996 and projected obligations for 1997 through 2001, including the impact of the 1995 settlement agreement with NCMPA and PMPA (See Note 13), are as follows (dollars in thousands):

<TABLE>
<CAPTION>

YEAR	PURCHASED CAPACITY CAPITAL COST	PURCHASED CAPACITY FIXED O&M	TOTAL PURCHASED CAPACITY
<S>	<C>	<C>	
1996 Actual	$ 84,303	$40,499	$ 124,802
1997 Projected	$ 67,030	$34,858	$ 101,888
1998 Projected	$ 48,423	$26,388	$ 74,811
1999 Projected	$ 35,337	$19,122	$ 54,459
`00 Projected	$ 4,286	$ 2,470	$ 6,756
.01 Projected	--	--	--

</TABLE>

Effective in its November 1991 rate order, the North Carolina Utilities Commission reaffirmed the Company's recovery, on a levelized basis, of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners. The Public Service Commission of South Carolina in its November 1991 rate order reaffirmed the Company's recovery on a levelized basis of the capital costs of capacity purchased from the other joint owners. Levelization was reaffirmed through inclusion in rates approved in March 1992 by the Federal Energy Regulatory Commission (FERC). The portion of purchased capacity subject to levelization not currently recovered in rates is being deferred, and the Company is recording a deferred return on the accumulated balance. The Company recovers the accumulated balance, including the deferred return, when the sum of the declining purchased capacity payments and accrual of deferred returns for the current period drops below the levelized revenues. Jurisdictional levelizations are intended to recover total costs, including deferred returns, and are subject to adjustments, including final true-ups. The Company recovers the costs of purchased energy and the non-levelized portion of purchased capacity on a current basis.

The current levelized revenues approved in the Company's last general rate proceedings are $211,423,000, $94,137,000 and $6,815,000 for North Carolina retail, South Carolina retail and Other Wholesale (FERC), respectively. ·rchased power costs, subject to levelization, are deferred based on allocation tors of approximately 62 percent, 26 percent and 2 percent for North Carolina ·etail, South Carolina retail and Other Wholesale (FERC), respectively. The

PSCSC, on May 7, 1996, ordered a rate reduction in the form of a decrement rider for an interim true-up adjustment. (See Note 2.) The Company also recovers an allocated amount of purchased power costs in the pricing of supplemental sales made to the other joint owners on a current basis.

During 1996, in the North Carolina retail and FERC wholesale jurisdictions, annual levelized revenues exceeded purchased capacity payments and the accrual of deferred returns for the first time. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments and accrual of deferred returns.

For the years ended December 31, 1996, 1995 and 1994, the Company recorded purchased capacity and energy costs from the other joint owners of $151,174,000, $388,246,000 and $604,505,000, respectively. These amounts, after adjustments for the costs of capacity purchased not reflected in current rates, are included in "Net interchange and purchased power" in the Consolidated Statements of Income. As of December 31, 1996 and 1995, $892,000,000 and $965,473,000, respectively, associated with the cost of capacity purchased but not reflected in current rates have been accumulated in the Consolidated Balance Sheets as "Purchased capacity costs."

NOTE 4. INCOME TAX EXPENSE

Accumulated deferred income taxes consist primarily of the following (dollars in thousands):

<TABLE>
<CAPTION>

	DECEMBER 31, 1996		DECEMBER 31, 1995	
<S>	<C>	<C>	<C>	<C>
Excess tax over book depreciation at historical tax rates		$1,424,709		$1,387,925
Regulatory liability related to adjusting deferred taxes to the current statutory tax rate		(108,462)*		(114,538)*
Net excess tax over book depreciation		$1,316,247		$1,273,387
Regulatory asset related to restating to a pre-tax basis		597,398*		605,214*
Deferred purchased capacity costs		345,089		374,112
Book versus tax basis differences		42,963		60,443
Loss on bond redemptions		63,962		68,135
Other	10,353		913	
Total deferred income taxes		$2,376,012		$2,382,204

</TABLE>

* The net regulatory asset related to income taxes is $488,936,000 for 1996 and $490,676,000 for 1995.

Total deferred income tax liability was $2,932,260,000 as of December 31, 1996, and $2,946,711,000 as of December 31, 1995. Total deferred income tax asset was $556,248,000 as of December 31, 1996, and $564,507,000 as of December 31, 1995.

Income tax expense for the years ended December 31, 1996, 1995 and 1994 consisted of the following (dollars in thousands):

<TABLE>
<CAPTION>

	1996	1995	1994
>	<C>	<C>	<C>
Current income taxes			

Federal	$413,429	$377,237	$249,968
State	89,903	83,215	52,790
Total current income taxes	503,332	460,452	302,758
Deferred taxes, net			
Federal	(16,706)	13,466	83,359
State	295	3,770	22,153
Total deferred taxes, net	(16,411)	17,236	105,512
Investment tax credit amortization	(11,230)	(11,247)	(11,251)
Total income tax expense	$475,691	$466,441	$397,019

</TABLE>

Income taxes differ from amounts computed by applying the statutory tax rate to pre-tax income for the years ended December 31, 1996, 1995 and 1994 as follows (dollars in thousands):

<TABLE>
<CAPTION>

	1996	1995	1994
<S>	<C>	<C>	<C>
Income taxes on pre-tax income at the statutory federal rate of 35%	$421,980	$413,343	$362,563
Increase (reduction) in tax resulting from:			
Allowance for funds used during construction (AFUDC)	(5,538)	(8,079)	(9,594)
Amortization of investment tax credit deferrals	(11,230)	(11,247)	(11,251)
AFUDC in book depreciation/amortization	19,990	21,057	19,027
Deferred income tax flowback at rates higher than statutory	(6,389)	(5,675)	(5,530)
State income taxes, net of federal income tax benefits	58,242	56,210	47,872
Other items, net	(1,364)	832	(6,068)
Total income tax expense	$475,691	$466,441	$397,019

</TABLE>

<PAGE>

NOTE 5. SHORT-TERM BORROWINGS AND CREDIT FACILITIES

The following credit facilities were available to the Company at December 31, 1996 and 1995:

<TABLE>
<CAPTION>

TYPE OF FACILITY	LINE OF CREDIT AT DECEMBER 31, 1996	OUTSTANDING AT DECEMBER 31, 1996	LINE OF CREDIT AT DECEMBER 31, 1995	OUTSTANDING AT DECEMBER 31, 1995
<S>	<C>	<C>	<C>	<C>
Annually renewable lines of credit	$ 64,900,000	$ 8,550,000	$ 64,900,000	$29,300,000
Two-year revolving facilities (a)	40,000,000	--	40,000,000	--
Four-year revolving facilities (b)	235,000,000	42,000,000	210,000,000	30,043,000
Five-year revolving facilities (c)	355,000,000	--	355,000,000	--
	$ 694,900,000	$50,550,000	$ 669,900,000	$59,343,000

</TABLE>

) The Company had $40,000,000 in pollution control bonds, included in ong-term debt, outstanding throughout 1996 and 1995 backed by these facilities.

(b) The outstanding balances of $42,000,000 in 1996 and $30,043,000 in 1995 are included in long-term debt.

The Company had $130,000,000 in commercial paper, included in long-term debt, outstanding throughout 1996 and 1995 backed by these facilities.

Cash balances maintained at the banks on deposit were $11,336,000 as of December 31, 1996, and $17,120,000 as of December 31, 1995. Cash balances and fees compensate banks for their services, even though the Company has no formal compensating-balance arrangements. To compensate certain banks for credit facilities, the Company maintained balances of $45,000 as of December 31, 1996 and 1995. The Company retains the right of withdrawal with respect to the funds used for compensating-balance arrangements.

A summary of short-term borrowings is as follows (dollars in thousands):

<TABLE>
<CAPTION>

	TWELVE MONTHS ENDED		
	DECEMBER 31, 1996	DECEMBER 31, 1995	DECEMBER 31, 1994
<S>	<C>	<C>	<C>
Amount outstanding at end of period -- average rate of 6.05% as of December 31, 1996, 5.91% as of December 31, 1995, and 6.02% as of December 31, 1994	$105,550	$155,300	$107,100
Maximum amount outstanding during the period	$176,450	$264,300	$143,400
Average amount outstanding during the period	$ 56,343	$ 88,470	$ 24,161
Weighted-average interest rate for the period -- computed on a daily basis	5.33%	6.05%	4.58%

</TABLE>

NOTE 6. COMMON STOCK AND RETAINED EARNINGS

COMMON STOCK

As of December 31, 1996, a total of 9,004,659 shares was reserved for issuance for stock plans.

On February 27, 1996, the Board of Directors authorized the Company to repurchase up to $1 billion of its common stock over the next five years. As of December 31, 1996, approximately 3.3 million shares had been repurchased for $159 million. On January 28, 1997, the Board of Directors amended the program to expressly limit the number of shares authorized for repurchase under the program, from the initiation of the program through a date two years after the consummation of the proposed merger with PanEnergy Corp, to an amount not to exceed 15 million shares. (See Note 13.)

RETAINED EARNINGS

As of December 31, 1996, substantially all of the Company's retained earnings were unrestricted as to the declaration or payment of dividends.

<PAGE>

NOTE 7. PREFERRED AND PREFERENCE STOCK WITHOUT SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1996 and 1995:

<TABLE>
<CAPTION>

	PAR VALUE	SHARES
<S>	<C>	<C>
Preferred Stock	$ 100	12,500,000

Preferred Stock A	$ 25	10,000,000
Preference Stock	$ 100	1,500,000

</TABLE>

, of December 31, 1996 and 1995, there were no shares of preference stock outstanding. Preferred stock without sinking fund requirements as of December 31, 1996 and 1995, was as follows (dollars in thousands):

<TABLE>
<CAPTION>

RATE/SERIES	YEAR ISSUED	SHARES OUTSTANDING 1996	1995
<S>	<C>	<C>	<C>
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
7.85% S	1992	600,000	60,000	60,000
7.00% W	1993	500,000	50,000	50,000
7.04% Y	1993	600,000	60,000	60,000
7.72% (Preferred Stock A)	1992	1,600,000	40,000	40,000
6.375% (Preferred Stock A)	1993	2,400,000	60,000	60,000
Auction Series A	1990	750,000	75,000	75,000
Total			$450,000	$450,000

</TABLE>

NOTE 8. PREFERRED AND PREFERENCE STOCK WITH SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1996 and 1995:

<TABLE>
<CAPTION>

	PAR VALUE	SHARES
<S>	<C>	<C>
Preferred Stock	$ 100	12,500,000
Preferred Stock A	$ 25	10,000,000
Preference Stock	$ 100	1,500,000

</TABLE>

As of December 31, 1996 and 1995, there were no shares of preference stock outstanding. Preferred stock with sinking fund requirements as of December 31, 1996 and 1995, was as follows (dollars in thousands):

<TABLE>
<CAPTION>

RATE/SERIES	YEAR ISSUED	SHARES OUTSTANDING 1996	1995
<S>	<C>	<C>	<C>
5.95% B (Preferred Stock A)	1992	800,000	$ 20,000	$ 20,000
6.10% C (Preferred Stock A)	1992	800,000	20,000	20,000
6.20% D (Preferred Stock A)	1992	800,000	20,000	20,000
7.50% R	1992	850,000	85,000	85,000
6.20% T	1992	130,000	13,000	13,000
6.30% U	1992	130,000	13,000	13,000
6.40% V	1992	130,000	13,000	13,000
75% X	1993	500,000	50,000	50,000
Total			$234,000	$234,000

</TABLE>

The annual sinking fund requirements through 2001 are $0 in 1997, $4,250,000 in 1998, $24,250,000 in 1999, $37,250,000 in 2000 and $37,250,000 in 2001. Some additional redemptions are permitted at the Company's option.

The call provisions for the outstanding preferred stock specify various redemption prices not exceeding 108 percent of par value, plus accumulated dividends to the redemption date.

<PAGE>

DUKE POWER COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- CONTINUED

NOTE 9. LONG-TERM DEBT

Long-term debt outstanding as of December 31, 1996 and 1995, was as follows (dollars in thousands):

<TABLE>
<CAPTION>

SERIES	YEAR DUE	1996	1995
<S>	<C>	<C>	<C>
FIRST AND REFUNDING MORTGAGE BONDS:			
6.59%	1996	$ --	$ 3,000
5 3/8%	1997	72,600	72,600
5 5/8%	1997	100,000	100,000
5.17%	1998	50,000	50,000
7.5%	1999	100,000	100,000
6 1/4%	1999	65,000	65,000
5.76%	1999	5,000	5,000
[illegible]78%	1999	25,000	25,000
[illegible]79%	1999	30,000	30,000
8% B	1999	200,000	200,000
7%	2000	100,000	100,000
7% B	2000	100,000	100,000
5 7/8%	2001	150,000	150,000
6 5/8% B	2003	100,000	100,000
5 7/8% C	2003	75,000	75,000
6.125%	2003	75,000	75,000
8%	2004	75,000	75,000
6 1/4% B	2004	100,000	100,000
7.37%-7.41%	2004	100,000	100,000
7%	2005	200,000	200,000
6 3/8%	2008	125,000	125,000
8 3/4%	2021	150,000	150,000
8 3/8% B	2021	150,000	150,000
8 5/8%	2022	100,000	100,000
7 3/8%	2023	200,000	200,000
6 7/8% B	2023	200,000	200,000
7 7/8%	2024	150,000	150,000
6 3/4%	2025	150,000	150,000
7 1/2% B	2025	100,000	100,000
8.27%	2025	21,000	21,000
8.27%	2025	50,000	50,000
[illegible]8%	2025	2,000	2,000
[illegible]0%	2025	5,000	5,000
[illegible]95%	2027	15,584	15,681

7%	2033	150,000	150,000

<CAPTION>

SERIES	YEAR DUE	1996	1995
>	<C>	<C>	<C>
POLLUTION CONTROL BONDS:			
7.70%	2012	$ 20,000	$ 20,000
7.75% B	2017	10,000	10,000
7.50%	2017	25,000	25,000
3.58%	2014	40,000	40,000
5.80%	2014	77,000	77,000
Subtotal		3,463,184	3,466,281
OTHER LONG-TERM DEBT:			
Capitalized leases		11,265	7,477
Other long-term debt		146,539	147,410
Unamortized debt discount and premium, net		(56,995)	(61,674)
Current maturities of long-term debt		(174,726)	(4,295)
Subtotal (a)		3,389,267	3,555,199
SUBSIDIARY LONG-TERM DEBT:			
Crescent Resources, Inc. (b)		118,058	130,694
Nantahala Power and Light		68,372	33,288
Current maturities of long-term debt		(37,583)	(7,776)
Subtotal		148,847	156,206
Total long-term debt		$3,538,114	$3,711,405

</TABLE>

(a) Substantially all of Duke Power's electric plant was mortgaged as of December 31, 1996.

(b) Substantial amounts of Crescent Resources, Inc.'s real estate development projects, land and buildings are pledged as collateral.

<PAGE>

NOTE 9. LONG-TERM DEBT -- Continued

As of December 31, 1996 and 1995, the Company had $40,000,000 in pollution control revenue bonds backed by an unused, two-year revolving credit facility of $40,000,000. In addition, the Company had $130,000,000 in commercial paper outstanding throughout 1996 and 1995 backed by unused five-year revolving credit facilities. These facilities are on a fee basis. Both the $40,000,000 in pollution control bonds and the $130,000,000 in commercial paper are included in long-term debt.

As of December 31, 1996, Crescent Resources, Inc. had $45,428,000 in mortgage loans which mature through 1999 and $30,630,000 in mortgage loans maturing in 2000 or thereafter. Additionally, Crescent Resources, Inc. had $2,000,000 outstanding at December 31, 1996, included in long-term debt on a $5,000,000 four-year revolving credit facility. Interest rates are variable and at December 31, 1996, ranged from 5.95 percent to 7.10 percent. As of December

31, 1996, Nantahala Power and Light Company had $68,000,000 in senior notes maturing in 2011, 2012 and 2016. The notes carry fixed interest rates of 9.21 percent, 7.45 percent and 6.90 percent and require monthly payments of principal beginning in 1997, 1998 and 2002, respectively.

The annual maturities of consolidated long-term debt, including capitalized lease principal payments through 2001, are $212,309,000 in 1997; $62,759,000 in 1998; $444,840,000 in 1999; $248,271,000 in 2000; and $154,541,000 in 2001.

NOTE 10. FINANCIAL INSTRUMENTS

The carrying amounts of "Cash," "Short-term investments," and "Notes payable" on the Consolidated Balance Sheets approximate fair value primarily because of the short maturities of these instruments. "Other investments" includes notes receivable issued at fixed rates with maturities up to 30 years for which there are no quoted market prices. The majority of estimated fair value amounts of long-term debt and preferred stock as disclosed below were obtained from independent parties. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 1996 and 1995, are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

External funds have been established, as required by the Nuclear Regulatory Commission, as a mechanism to fund certain costs of nuclear decommissioning. (See Note 14.) Currently, these nuclear decommissioning trust funds are invested in U.S. stocks, bonds and cash equivalents. "Nuclear decommissioning trust funds" are presented on the Consolidated Balance Sheets at amounts that approximate fair value.

The carrying amounts and estimated fair values of long-term debt and preferred stock are as follows (dollars in thousands):

<TABLE>
<CAPTION>

	DECEMBER 31, 1996		DECEMBER 31, 1995	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
<S>	<C>	<C>	<C>	<C>
Long-term debt	$ 3,796,153	$3,773,000	$ 3,777,672	$3,879,000
Preferred stock	$ 684,000	$ 699,000	$ 684,000	$ 689,000

</TABLE>

The Company has authority to issue up to $1 billion aggregate principal amount of debt securities under a shelf registration statement filed with the Securities and Exchange Commission (SEC). Such debt securities may be issued as First and Refunding Mortgage Bonds, Senior Notes or Subordinated Debentures.

In order to obtain variable rate financing at an attractive cost, the Company entered into interest rate swap agreements associated with the November 1994, issuance of $200 million aggregate principal amount of its First and Refunding Mortgage Bonds, 8% Series B due 1999 and the August 1995, issuance of $100 million aggregate principal amount of its First and Refunding Mortgage Bonds, 7 1/2% Series B due 2025. The interest rate swaps are reset quarterly based upon the three-month London Interbank Offered Rate (LIBOR). As a result of the interest rate swap contracts, interest expense on the Consolidated

<PAGE>

NOTE 10. FINANCIAL INSTRUMENTS -- Continued

Statements of Income is recognized at the weighted average rate for the year tied to the LIBOR rate. The weighted average rates are as follows (dollars in ousands):

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APTION>

SERIES	YEAR DUE	FACE VALUE	WEIGHTED AVERAGE RATE 1996	1995	1994
<S>	<C>	<C>	<C>	<C>	
8% Series B	1999	$200,000	5.64%	6.14%	5.95%
7 1/2% Series B	2025	$100,000	6.69%	7.06%	--

</TABLE>

Duke Energy Group, Inc. entered into a hedge transaction in 1995 to offset currency fluctuations between the U.S. dollar and the Chilean peso associated with expected equity contributions to an affiliate in 1995, 1996 and 1997. The hedge transaction has a notional amount of approximately $4.4 million at December 31, 1996. Duke Energy Group, Inc. records any realized gains or losses associated with the hedge as an adjustment to investments in affiliates.

NOTE 11. INVESTMENTS IN AFFILIATES

Certain investments, where the Company's ownership in domestic and international affiliates is 50 percent or less, are accounted for by the equity method. These investments include ownership interests in various power development projects; start-up personal communications services; marketing of natural gas, electric power, and development of other energy services; participation in various construction and support activities for fossil-fueled generating plants; and real-estate development projects. The Company's proportionate share of net income (loss) from these affiliates for the years ded December 31, 1996, 1995 and 1994 was $(6,133,000), $9,237,000 and ,049,000, respectively. These amounts are reflected in "Operating revenues" on the Consolidated Statements of Income.

A summary of assets and liabilities of these affiliates follows (dollars in thousands):

<TABLE>
<CAPTION>

	DECEMBER 31, 1996 TOTAL	DECEMBER 31, 1996 COMPANY'S PROPORTIONATE SHARE	DECEMBER 31, 1995 TOTAL	DECEMBER 31, 1995 COMPANY'S PROPORTIONATE SHARE
<S>	<C>	<C>	<C>	<C>
Assets of affiliates	$1,979,418	$ 549,442	$1,445,600	$ 351,376
Liabilities of affiliates	$1,041,207*	$ 360,460	$ 615,452*	$ 188,102

</TABLE>

* The Company's exposure to these liabilities is mitigated through the use of project or limited recourse financing by the affiliates and capitalization of its subsidiaries investing in the affiliates.

In addition, the Company had outstanding loans to certain affiliates of $2,900,000 and $23,170,000 at December 31, 1996 and 1995, respectively.

In the normal course of business, some of these affiliates enter into contractual agreements to exchange natural gas, electric power, futures, swaps and options; and construction contracts which contain certain schedule and rformance requirements. The affiliates use risk management procedures to ntrol their exposure associated with the contracts. Certain subsidiaries of he Company have guaranteed performance of the affiliates under some of these

contracts. Management is of the opinion that these guarantees will not have any material adverse effect on the results of operations or the financial position of the Company.

NOTE 12. RETIREMENT BENEFITS

A. RETIREMENT PLAN

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own retirement plans, have a non-contributory, defined benefit retirement plan covering substantially all their employees. Through December 31, 1996, the benefit was based upon an age-related formula which took into account years of creditable service and the employee's average compensation based upon the highest compensation during a consecutive sixty-month period. The benefit was reduced by an adjustment which is based upon the employee's social security wages. Normal retirement age under the Plan was age 65; however, early retirement benefits were payable as early as age 55 with 10

<PAGE>

years of creditable service or age 51 if the employee had at least 30 years of creditable service. The Company's policy is to fund pension costs as accrued.

Effective January 1, 1997, the Plan was amended to be a Cash Balance Plan. Under the Cash Balance Plan, records are maintained on an individual participant basis with monthly credits based upon the participant's creditable compensation multiplied times a percentage that ranges from 3 percent to 7 percent depending on the sum of the participant's age and years of service. An additional credit of 4 percent applies to creditable compensation in excess of the social security wage base. Additionally, monthly interest credits will be allocated based upon the yield of 30-year U.S. Treasury Bonds, subject to a 4 percent minimum and a 9 percent maximum yield. Normal retirement age will remain age 65. Employees who were participants in the Plan before January 1, 1997, remain eligible to receive certain transitional benefits under the provisions of the previous plan. After January 1, 1997, employees can receive early retirement benefits as early as age 55 with at least 5 years of vesting service.

Net periodic pension cost for the years ended December 31, 1996, 1995 and 1994, include the following components (dollars in thousands):

<TABLE>
<CAPTION>

	1996	1995	1994
<S>	<C>	<C>	<C>
Service cost benefit earned during the year	$ 49,636	$ 46,402	$ 43,098
Interest cost on projected benefit obligation	116,088	111,110	96,521
Actual return on plan assets	(180,463)	(253,314)	(6,138)
Amount deferred for recognition	58,705	144,022	(86,995)
Expected return on plan assets	(121,758)	(109,292)	(93,133)
Net amortization	9,070	6,161	7,657
Net periodic pension cost	$ 53,036	$ 54,381	$ 54,143

</TABLE>

A reconciliation of the funded status of the plan to the amounts recognized the Consolidated Balance Sheets as of December 31, 1996 and 1995, is as follows (dollars in thousands):

<TABLE>
<CAPTION>

	1996	1995
>	<C>	<C>
;cumulated benefit obligation:		
Vested benefits	$(1,453,115)	$(1,289,459)
Nonvested benefits	(4,083)	(6,216)
Accumulated benefit obligation	$(1,457,198)	$(1,295,675)
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$ 1,587,812	$ 1,424,148
Projected benefit obligation	(1,663,375)	(1,596,747)
Unrecognized net experience loss	220,355	286,837
Unrecognized prior service cost reduction	(65,460)	(35,039)
Remaining unrecognized transitional obligation	668	801
Pre-funded pension cost	$ 80,000	$ 80,000

</TABLE>

Assumptions used in the Company's pension accounting include:

<TABLE>
<CAPTION>

	1996	1995	1994
<S>	<C>	<C>	<C>
Weighted-average discount rate	7.50%	7.50%	8.25%
Weighted-average salary increase	4.75%	4.75%	5.40%
Expected long-term rate of return on plan assets	9.00%	9.00%	9.00%

</TABLE>

During 1995, the Company offered to certain employees an Enhanced Vested Benefits program (EVB). The Company recorded an additional one-time expense for special termination benefits associated with EVB of approximately $42,196,000, including $21,600,000 of additional retirement plan costs.

<PAGE>

NOTE 12. RETIREMENT BENEFITS -- Continued

B. POSTRETIREMENT BENEFITS

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company (NP&L), which maintained its own postretirement benefit plans through December 1995, currently provide certain health care and life insurance benefits for retired employees. NP&L employees who retired after January 1, 1996, are covered by Duke Power Company's postretirement benefit plan. Through December 31, 1996, employees became eligible for these benefits if they retired at age 55 or greater with 10 years of service or if they retired as early as age 51 with 30 years or more of service. Effective January 1, 1997, employees who were participants in the Retirement Plan before January 1, 1997, become eligible for certain transitional postretirement benefits under the provisions of the previous plan. Employees who were not participants in the plan before January 1, 1997, become eligible as early as age 55 with at least 10 ars of vesting service. All employees retiring after January 1, 1992, receive ixed Company allowance, based on years of service, to be used to pay medical nsurance premiums. The Company reserves the right to terminate, suspend,

withdraw, amend or modify the plans in whole or in part at any time.

In 1992, the Company commenced funding the maximum amount allowable under section 401(h) of the Internal Revenue Code, which provides for tax deductions contributions and tax-free accumulation of investment income. Such amounts partially fund the Company's medical and dental postretirement benefits. The Company has also established a Retired Lives Reserve, which has tax attributes similar to 401(h) funding, to partially fund its postretirement life insurance obligation. The Company contributed $15,200,000 into these funding mechanisms in 1996 and $23,000,000 in 1995.

Net periodic postretirement benefit cost for the years ended December 31, 1996, 1995 and 1994, include the following components (dollars in thousands):

<TABLE>
<CAPTION>

	1996	1995	1994
<S>	<C>	<C>	<C>
Service cost benefit earned during the year	$ 6,388	$ 5,874	$ 5,415
Interest cost on accumulated postretirement benefit obligation	27,276	27,201	25,321
Actual return on plan assets	(12,383)	(14,726)	(1,451)
Amount deferred for recognition	2,988	7,260	(3,469)
Expected return on plan assets	(9,395)	(7,466)	(4,920)
Straight-line -- 20 year amortization of transitional obligation	13,515	13,293	13,293
Other amortization	1,566	555	366
Net periodic postretirement benefit cost	$39,350	$39,457	$39,475

</TABLE>

A reconciliation of the funded status of the plan to the amounts recognized the Consolidated Balance Sheets as of December 31, 1996 and 1995, is as follows (dollars in thousands):

<TABLE>
<CAPTION>

	1996	1995
<S>	<C>	<C>
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$ 127,594	$ 105,506
Actives eligible to retire	(39,567)	(25,780)
Actives not eligible to retire	(118,103)	(97,389)
Retirees and surviving spouses	(251,325)	(253,688)
Accumulated postretirement benefit obligation (APBO)	(408,995)	(376,857)
Unrecognized prior service cost	66,692	712
Unrecognized net experience (gain)/loss	(3,772)	25,955
Unrecognized transitional obligation	177,338	212,695
(Accrued) postretirement benefit cost	$ (41,143)	$ (31,989)

</TABLE>

<PAGE>

NOTE 12. RETIREMENT BENEFITS -- Continued

Assumptions used in the Company's postretirement benefits accounting

include:
<TABLE>
<CAPTION>

	1996	1995	1994
>	<C>	<C>	<C>
Weighted-average discount rate	7.50%	7.50%	8.25%
Weighted-average salary increase	4.75%	4.75%	5.40%
Expected long-term rate of return on 401(h) assets	9.00%	9.00%	9.00%
Expected long-term rate of return on RLR assets	6.50%	8.00%	6.50%

</TABLE>

The assumed medical inflation rate was approximately 9.5 percent in 1996. This rate decreases by 0.5 percent to 1.0 percent per year until a rate of 5.5 percent is achieved in the year 2001, which remains fixed thereafter.

A 1.0 percent increase in the medical and dental trend rates produces a 7.0 percent ($2,940,971) increase in the aggregate service and interest cost. The increase in the APBO attributable to a 1.0 percent increase in the medical and dental trend rates is 7.8 percent ($31,462,000) as of December 31, 1996.

NOTE 13. COMMITMENTS AND CONTINGENCIES

A. CONSTRUCTION PROGRAM

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including allowance for funds used during construction, are $2.6 billion and $716 million, respectively, for 1997 through 2001. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

Projected capital expenditures of subsidiaries and diversified activities e $1.5 billion for 1997 through 2001. These projections are subject to periodic review and revisions and may vary significantly as business plans evolve to meet the opportunities presented by their markets.

B. NUCLEAR INSURANCE

The Company maintains nuclear insurance coverage in three areas: liability coverage, property, decontamination and decommissioning coverage, and extended accidental outage coverage to cover increased generating costs and/or replacement power purchases. The Company is being reimbursed by the other joint owners of the Catawba Nuclear Station for certain expenses associated with nuclear insurance premiums paid by the Company.

Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $8.9 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $8.7 billion, which will be increased by $79.3 million as each additional commercial nuclear reactor is licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. The $8.7 billion could also be reduced by $79.3 million for certain nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs and public liability damages exceed primary surances, licensees may be assessed up to $79.3 million for each of their ensed reactors, payable at a rate not to exceed $10 million a year per nsed reactor for each incident. The $79.3 million amount is subject to

indexing for inflation and may be subject to state premium taxes. The $79.3 million includes a surcharge of 5 percent (which is also included in the above $[illegible]7 billion figure) if funds are insufficient to pay claims and associated [illegible]ts. If retrospective premiums were to be assessed, the other joint owners of [illegible] Catawba Nuclear Station are obligated to assume their pro rata share of such assessment.

The Company is a member of Nuclear Mutual Limited (NML), which provides $500 million in primary property damage coverage for each of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $34 million. This amount represents 5 times the Company's

<PAGE>

NOTE 13. COMMITMENTS AND CONTINGENCIES -- Continued

annual premium to NML. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NML policies applicable to Catawba.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. NEIL provides excess insurance coverage of $2.25 billion for the Catawba Nuclear Station and $1.5 billion for each of the Oconee and McGuire Nuclear Stations. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, the Company will be liable, on a pro rata [illegible]sis, for additional assessments of up to $40 million. This amount is limited [illegible]5 times the Company's annual premium to NEIL for excess property, decontamination and decommissioning liability insurance. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to Catawba.

The Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Each unit of the McGuire and Catawba Nuclear Stations is insured for up to approximately $3.5 million per week, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. The Oconee Nuclear Station units are insured for up to approximately $2.7 million, under like terms. Coverages continue at 100 percent for 52 weeks and 80 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $27 million. This amount represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to the joint ownership agreements.

C. PROPOSED MERGER WITH PANENERGY CORP

On November 25, 1996, the Company and PanEnergy Corp announced a proposed [illegible]ock-for-stock transaction creating an integrated energy company. Upon [illegible]nsummation of the merger, PanEnergy will be a wholly owned subsidiary of the [illegible]ompany, and the Company's name will be changed to Duke Energy Corporation. The

transaction is expected to close by December 31, 1997, subject to approval of the shareholders of both companies and all applicable regulatory approvals. The shareholders of each company will vote on the proposed merger at their annual meetings, which are scheduled for April 24, 1997 for both companies. Applications for regulatory approval were filed with the NCUC and the PSCSC on December 19, 1996 and the FERC on February 3, 1997. Regulatory proceedings are expected to be successfully completed by year-end 1997. In connection with the transaction, each share of PanEnergy common stock will be converted into 1.0444 shares of common stock of the Company. The transaction will be accounted for as a pooling of interests. Further details about the proposed acquisition are provided in the Company's report on Form 8-K, filed with the Securities and Exchange Commission on December 9, 1996, and in the Joint Proxy Statement-Prospectus provided to shareholders in connection with the Company's annual meeting. Unless otherwise indicated, all information presented herein relates to the Company only and does not take into account the proposed merger with PanEnergy.

D. OTHER

The Company and North Carolina Municipal Power Agency Number 1 and Piedmont Municipal Power Agency, two of the four other joint owners of the Catawba Nuclear Station, entered into a settlement in September 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the North Carolina Utilities Commission on January 16, 1996 and The Public Service Commission of South Carolina on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or the financial position of the Company.

<PAGE>

NOTE 13. COMMITMENTS AND CONTINGENCIES -- Continued

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (See Note 3.) In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to

"Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or financial position of the Company.

NOTE 14. NUCLEAR DECOMMISSIONING COSTS

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the North Carolina Utilities Commission and the Public Service Commission of South Carolina have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume each unit will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 -- 2013, Oconee 3 -- 2014; McGuire 1 -- 2021, McGuire 2 -- 2023; and Catawba 1 -- 2024, Catawba 2 -- 2026.

In accordance with a 1988 Nuclear Regulatory Commission order, during 1996, the Company expensed approximately $56,470,000 which was contributed to the external funds for decommissioning costs and accrued an additional $1,618,000 to the internal reserve. Nuclear units are depreciated at a rate of 4.70 percent, of which 1.61 percent is for decommissioning. The balance of the external funds as of December 31, 1996, was $362,627,000. The balance of the internal reserve as of December 31, 1996, was $207,774,000 and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

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INDEPENDENT AUDITORS' REPORT

DUKE POWER COMPANY:

We have audited the consolidated financial statements of Duke Power Company and subsidiaries (the Company) listed in the accompanying index for Item 8. Our audits also included the consolidated financial statement schedule listed in the accompanying index. These financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material

misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1996 and 1995, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1996 in conformity with generally accepted accounting principles. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

Charlotte, North Carolina
February 7, 1997

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements of Duke Power Company are prepared by management, which is responsible for their integrity and objectivity. The statements are prepared in conformity with generally accepted accounting principles appropriate in the circumstances to reflect in all material respects the substance of events and transactions which should be included. The other information in the annual report is consistent with the financial statements. In preparing these statements, management makes informed judgments and estimates of the expected effects of events and transactions that are currently being reported.

The Company's system of internal accounting control is designed to provide reasonable assurance that assets are safeguarded and transactions are executed according to management's authorization. Internal accounting controls also provide reasonable assurance that transactions are recorded properly, so that financial statements can be prepared according to generally accepted accounting principles. In addition, the Company's accounting controls provide reasonable assurance that errors or irregularities which could be material to the financial statements are prevented or are detected by employees within a timely period as they perform their assigned functions. The Company's accounting controls are continually reviewed for effectiveness. In addition, written policies, standards and procedures, and a strong internal audit program augment the Company's accounting controls.

The Board of Directors pursues its oversight role for the financial statements through the audit committee, which is composed entirely of directors who are not employees of the Company. The audit committee meets with management and internal auditors periodically to review the work of each group and to monitor each group's discharge of its responsibilities. The audit committee also meets periodically with the Company's independent auditors, Deloitte & Touche LLP. The independent auditors have free access to the audit committee and the Board of Directors to discuss internal accounting control, auditing and financial reporting matters without the presence of management.

JEFFREY L. BOYER
CONTROLLER

<PAGE>

QUARTERLY FINANCIAL DATA

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CAPTION>

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	TOTAL
<S>	<C>	<C>	<C>	<C>	<C>
	DOLLARS IN THOUSANDS (EXCEPT PER-SHARE DATA)				
96 BY QUARTER					
Operating revenues	$1,162,077	$1,119,731	$1,292,426	$1,183,740	$4,757,974
Operating income	$ 357,412	$ 301,231	$ 470,706	$ 232,854	$1,362,203
Net income	$ 191,304	$ 157,382	$ 264,987	$ 116,293	$ 729,966
Earnings per share	$ 0.88	$ 0.71	$ 1.25	$ 0.53	$ 3.37
1995 BY QUARTER					
Operating revenues	$1,111,065	$1,052,403	$1,379,978	$1,133,238	$4,676,684
Operating income	$ 369,414	$ 263,876	$ 504,507	$ 211,254	$1,349,051
Net income	$ 201,276	$ 137,523	$ 285,200	$ 90,539	$ 714,538
Earnings per share	$ 0.92	$ 0.61	$ 1.33	$ 0.39	$ 3.25

Generally, quarterly earnings fluctuate with seasonal weather conditions and maintenance of electric generating units, especially nuclear units.

<PAGE>

SUBSIDIARIES AND DIVERSIFIED ACTIVITIES HIGHLIGHTS

The Company has organized all its subsidiaries and diversified activities into the Associated Enterprises Group (AEG). AEG includes the following:

(Bullet) CHURCH STREET CAPITAL CORP. (CSCC) serves as the parent company and provides equity funding and credit enhancement services for the Company's non-electric operating subsidiaries. CSCC and one of its wholly-owned subsidiaries manage investment funds, highlights of which are as follows (dollars in thousands):

SHORT-TERM INVESTMENTS AND MARKETABLE SECURITIES

1996	1995	1994
<S>	<C>	<C>
$72,712	$76,300	$170,642

INVESTMENT INCOME (AFTER TAX)

1996	1995	1994
<S>	<C>	<C>
$772	$4,783	$7,562

(Bullet) CRESCENT RESOURCES, INC. provides real estate management, forestry operation and high-quality commercial and residential real estate development services in the Southeast.

(Bullet) DUKE ENERGY GROUP, INC. develops, owns, manages and operates energy facilities worldwide.

(Bullet) DUKE ENGINEERING & SERVICES, INC. provides engineering, project management, quality assurances, construction

management, operating and maintenance and environmental services for utilities, industry and government worldwide.

(Bullet) DUKE/FLUOR DANIEL provides engineering, procurement, construction and operating and maintenance services for fossil-fueled electric generating stations worldwide.

(Bullet) DUKE/LOUIS DREYFUS, LLC markets electric power, natural gas and energy-related services to utilities, municipalities and other large energy users in North America.

(Bullet) DUKE MERCHANDISING sells and services home appliances, electronics and wireless communications devices.

(Bullet) DUKENET COMMUNICATIONS, INC. develops and manages communications systems, including fiber optic and wireless digital network services.

(Bullet) DUKE WATER OPERATIONS provides franchised water service to customers in parts of North and South Carolina.

(Bullet) NANTAHALA POWER AND LIGHT COMPANY is a franchised electricity provider serving a five-county area in western North Carolina.

<PAGE>

The following tables set forth operating results, financial position, cash flows and other information with respect to the Company's subsidiaries and diversified activities for the periods and as of the dates specified:

OPERATING RESULTS

<TABLE>
<CAPTION>

	YEAR ENDED DECEMBER 31,		
	1996	1995	1994
<S>	<C>	<C>	<C>
	DOLLARS IN THOUSANDS		
OPERATING REVENUES			
Crescent Resources, Inc.	$113,759	$ 85,361	$ 64,724
Duke Energy Group, Inc.	13,095	10,017	9,478
Duke Engineering & Services, Inc. (a)	157,209	64,880	41,670
Nantahala Power and Light Company	67,668	62,510	68,595
All Other Business Units (b)	63,463	76,457	68,262
Total Associated Enterprises Group	$415,194	$299,225	$252,729
OPERATING INCOME			
Crescent Resources, Inc.	$ 87,708	$ 63,973	$ 46,236
Duke Energy Group, Inc. (c)	(11,795)	(1,422)	(1,035)
Duke Engineering & Services, Inc. (a)	12,924	5,941	2,681
Nantahala Power and Light Company	14,677	9,262	12,224
All Other Business Units (b)	(5,204)	14,466	12,825
Total Associated Enterprises Group	$ 98,310	$ 92,220	$ 72,931
NET INCOME			
Crescent Resources, Inc.	$ 49,600	$ 35,500	$ 26,525
Duke Energy Group, Inc. (c)(d)	(7,377)	170	5,749
Duke Engineering & Services, Inc. (a)	7,896	3,701	1,675
Nantahala Power and Light Company	6,265	4,037	6,169
All Other Business Units (b)	(5,106)	10,849	11,918
Total Associated Enterprises Group	$ 51,278	$ 54,257	$ 52,036

TABLE>

FINANCIAL POSITION

<TABLE>
<CAPTION>

	DECEMBER 31, 1996	1995	1994
<S>	<C>	<C>	<C>
	DOLLARS IN THOUSANDS		
TOTAL ASSETS			
Crescent Resources, Inc.	$ 446,307	$381,073	$294,175
Duke Energy Group, Inc.	131,210	149,391	110,656
Duke Engineering & Services, Inc. (a)	115,457	44,090	18,412
Nantahala Power and Light Company	167,008	144,069	125,883
All Other Business Units (b)	312,007	239,684	261,018
Total Associated Enterprises Group	$1,171,989	$958,307	$810,144
TOTAL LIABILITIES			
Crescent Resources, Inc.	$ 201,809	$185,996	$134,574
Duke Energy Group, Inc.	6,204	9,783	4,672
Duke Engineering & Services, Inc. (a)	36,540	10,969	5,992
Nantahala Power and Light Company	105,787	86,691	72,542
All Other Business Units (b)	37,994	32,529	16,320
Total Associated Enterprises Group	$ 388,334	$325,968	$234,100

</TABLE>

<PAGE>

CASH FLOWS

<TABLE>
<CAPTION>

	YEAR ENDED DECEMBER 31, 1996	1995	1994
<S>	<C>	<C>	<C>
	DOLLARS IN THOUSANDS		
CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES			
Crescent Resources, Inc.	$ 90,154	$ 40,144	$ 37,691
Duke Energy Group, Inc.	(8,763)	(3,521)	(6,614)
Duke Engineering & Services, Inc. (a)	297	4,921	2,252
Nantahala Power and Light Company	9,448	8,419	12,817
All Other Business Units (b)	5,026	(3,152)	8,337
Total Associated Enterprises Group	$ 96,162	$ 46,811	$ 54,483
CASH PROVIDED BY INVESTING ACTIVITIES			
Crescent Resources, Inc. (e)	$ 37,786	$ 5,910	$ 2,524
Duke Energy Group, Inc. (f)	27,046	14,253	40,740
Duke Engineering & Services, Inc. (a)	--	--	--
Nantahala Power and Light Company	--	--	--
All Other Business Units (g)	4,951	97,793	5,100
Total Associated Enterprises Group	$ 69,783	$117,956	$ 48,364
CASH USED IN INVESTING ACTIVITIES			
Crescent Resources, Inc.	$115,371	$ 84,603	$ 78,689
Duke Energy Group, Inc.	14,029	44,776	19,575
Duke Engineering & Services, Inc. (a)(h)	40,890	996	1,090
Nantahala Power and Light Company	21,166	23,944	23,989
All Other Business Units (i)	46,161	65,772	17,410
Total Associated Enterprises Group	$237,617	$220,091	$140,753

</TABLE>

CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES (J)

Crescent Resources, Inc.	$(12,497)	$ 38,521	$ 37,589
Duke Energy Group, Inc. (k)	--	--	--
Duke Engineering & Services, Inc. (a)(l)	375	997	--
Nantahala Power and Light Company	11,659	15,536	10,896
All Other Business Units (m)	69,463	4,305	(6,993)
Total Associated Enterprises Group	$ 69,000	$ 59,359	$ 41,492

</TABLE>

OTHER INFORMATION

<TABLE>
<CAPTION>

	DECEMBER 31,		
	1996	1995	1994
<S>	<C>	<C>	<C>
FULL-TIME EMPLOYEES AT YEAR-END			
Crescent Resources, Inc.	118	94	89
Duke Energy Group, Inc.	52	43	35
Duke Engineering & Services, Inc. (a)	1,834	551	275
Nantahala Power and Light Company	193	182	184
All Other Business Units	527	485	428
Total Associated Enterprises Group	2,724	1,355	1,011

</TABLE>

(a) Excludes operations and financial position of an affiliate, Duke/Fluor Daniel, which is included in All Other Business Units amounts.
(b) All Other Business Units amounts include Associated Enterprises Group intercompany eliminations.
(c) 1996 includes a provision for an investment in a power plant in Argentina.
(d) 1994 includes a gain from the sale of preferred stock.
(e) 1996 includes proceeds from sale of office building.

<PAGE>

(f) 1996 includes proceeds from repayment of a loan by an affiliate. (See Note 11.) 1994 includes proceeds from the sale of preferred stock and debt securities.
(g) 1996 and 1995 include the net change in short-term investments for the period of $3,588,000 and $56,392,000, respectively. Also, 1995 includes proceeds from the sale of a dividend capture program.
(h) 1996 includes amounts paid relating to acquisition activities.
(i) 1994 includes the net change in short-term investments for the period of $12,060,000.
(j) Excludes capital infusion and return of capital transactions between parent, Church Street Capital Corp., and its subsidiaries.
(k) 1996 and 1994 exclude net return of capital to parent, Church Street Capital Corp., of $4,724,000 and $12,100,000, respectively. 1995 excludes net capital infusions from Church Street Capital Corp. of $33,455,000.
(l) 1996 excludes net capital infusions from parent, Church Street Capital Corp., of $35,900,000.
(m) 1996 includes capital infusion from Duke Power to Church Street Capital Corp. of $65,000,000.

<PAGE>
SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
<TABLE>
APTION>

DESCRIPTION	BALANCE BEGINNING OF YEAR	BALANCE END OF YEAR
<S>	<C>	<C>
	(DOLLARS IN THOUSANDS)	
FOR THE YEAR ENDED DECEMBER 31, 1996		
Reserves Related to Assets on Balance Sheet	$ 7,774	$ 8,562
Other Reserves		
Operating Reserves (1)	176,098	178,583
FOR THE YEAR ENDED DECEMBER 31, 1995		
Reserves Related to Assets on Balance Sheet	8,059	7,774
Other Reserves		
Operating Reserves (1)	154,722	176,098
FOR THE YEAR ENDED DECEMBER 31, 1994		
Reserves Related to Assets on Balance Sheet	10,353	8,059
Other Reserves		
Operating Reserves (1)	107,477	154,722

</TABLE>

(1) Principally consists of Injuries and Damages reserves and Property Insurance reserve which are included in "Deferred Credits and Other Liabilities" in the Consolidated Balance Sheets.

<PAGE>
ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

No events necessary to be disclosed by the Company under this item have occurred.

PART III.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

Information for this item concerning directors of the Company is set forth in the sections entitled "Election of Directors," "Information Regarding the Board of Directors" and "Common Stock Ownership of Certain Beneficial Owners and Management" under "The Duke Meeting -- Additional Matters" in the Joint Proxy Statement-Prospectus relating to the Company's 1997 annual meeting of shareholders, which are being incorporated herein by reference.

Information concerning the executive officers of the Company is set forth in the section entitled "Executive Officers of the Company" in this annual report.

ITEM 11. EXECUTIVE COMPENSATION.

Information for this item is set forth in the sections entitled "Executive Compensation" and "Directors' Fees" under "The Duke Meeting -- Additional Matters", and "Interests of Certain Persons in the Merger -- Duke Employment Agreements" under "The Merger" in the Joint Proxy Statement-Prospectus relating to the Company's 1997 annual meeting of shareholders, which are being corporated herein by reference.

EM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

Information for this item is set forth in the section entitled "Common

Stock Ownership of Certain Beneficial Owners and Management" under "The Duke Meeting -- Additional Matters" in the Joint Proxy Statement-Prospectus relating the Company's 1997 annual meeting of shareholders, which is being incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Information for this item is set forth in the sections entitled "Information Regarding the Board of Directors" and "Common Stock Ownership of Certain Beneficial Owners and Management" under "The Duke Meeting -- Additional Matters" in the Joint Proxy Statement-Prospectus relating to the Company's 1997 annual meeting of shareholders, which are being incorporated herein by reference.

<PAGE>

PART IV.

ITEM 14. EXHIBITS, CONSOLIDATED FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Consolidated Financial Statements

Consolidated Statements of Income for the Three Years Ended December 31, 1996

Consolidated Statements of Retained Earnings for the Three Years Ended December 31, 1996

Consolidated Statements of Cash Flows for the Three Years Ended December 31, 1996

Consolidated Balance Sheets -- December 31, 1996 and 1995

Notes to Consolidated Financial Statements

Selected Quarterly Financial Data (unaudited)

Consolidated Financial Statement Schedule

Schedule II -- Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 1996

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements or notes thereto.

(b) Reports on Form 8-K

A Report on Form 8-K was filed by the Company on December 9, 1996, in which it reported in Item 5 thereof the execution of an Agreement and Plan of Merger dated as of November 24, 1996, by and between the Company, Duke Transaction Corporation and PanEnergy Corp.

(c) Exhibits -- See Exhibit Index immediately following signature page.

<PAGE>

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Charlotte and State of North Carolina on the 24th day of March, 1997.

DUKE POWER COMPANY
(Registrant)

By: W. H. GRIGG
CHAIRMAN OF THE BOARD
AND CHIEF EXECUTIVE OFFICER

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

<TABLE>
<CAPTION>

SIGNATURE	TITLE	DATE
<S>	<C>	<C>
W. H. GRIGG	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	March 24, 1997
RICHARD J. OSBORNE	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 24, 1997
JEFFREY L. BOYER	Controller (Principal Accounting Officer)	March 24, 1997
G. ALEX BERNHARDT ROBERT J. BROWN W. A. COLEY STEVE C. GRIFFITH, JR. (Buzzard wing appears here) W. H. GRIGG GEORGE DEAN JOHNSON, JR. W. W. JOHNSON MAX LENNON JAMES G. MARTIN BUCK MICKEL R. B. PRIORY RUSSELL M. ROBINSON, II	A majority of the Directors	March 24, 1997

</TABLE>

ELLEN T. RUFF, by signing her name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

/s/ ELLEN T. RUFF
ELLEN T. RUFF, ATTORNEY-IN-FACT

<PAGE>

EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the Securities and Exchange Commission and pursuant to Rule 12b- 32 are incorporated herein by reference.

<TABLE>
<CAPTION>

EXHIBIT NUMBER	
<S> <C>	<C> <C>
2	--Agreement and Plan of Merger, dated as of November 24, 1996, as amended and restated as of March 10, 1997, among registrant, Duke Transaction Corporation and PanEnergy Corp (filed with Form 8-K dated March 20, 1997, File No. 1-4928, as Exhibit 2(a)).
3-A	--Restated Articles of Incorporation of registrant, dated as of October 6, 1993 (filed with Form S-3, File No. 33-50617, effective October 20, 1993, as Exhibit 4(A)).
3-B	--Articles of Amendment of registrant dated November 1, 1993, relating to the 6.375% Cumulative Preferred Stock A, 1993 Series (filed with Form S-3, No. 33-52479, effective March 29, 1994, as Exhibit 4(B)).

3-C --By-Laws of registrant, as amended (filed with Form 10-K for the year ended December 31, 1995, File No. 1-4928, as Exhibit 3-C).

4-B-1 --First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated of December 1, 1927 (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(a)).

4-B-2 --Supplemental Indenture, dated as of March 12, 1930, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).

4-B-5 --Supplemental Indenture, dated as of September 1, 1936, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).

4-B-6 --Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).

4-B-7 --Supplemental Indenture, dated as of April 1, 1944, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).

4-B-8 --Supplemental Indenture, dated as of September 1, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).

4-B-9 --Supplemental Indenture, dated as of September 8, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).

4-B-10 --Supplemental Indenture, dated as of February 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).

4-B-11 --Supplemental Indenture, dated as of March 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).

4-B-14 --Supplemental Indenture, dated as of October 1, 1954, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).

4-B-17 --Supplemental Indenture, dated as of January 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).

4-B-18 --Supplemental Indenture, dated as of February 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).

4-B-21 --Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 3, 1966, as Exhibit 4-B-20).

4-B-23 --Supplemental Indenture, dated as of April 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-28023, effective February 15, 1968, as Exhibit 2-B-25).

4-B-24 --Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No. 2-31304, effective January 21, 1969, as Exhibit 2-B-26).

4-B-48 --Supplemental Indenture, dated as of September 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-48).

4-B-49 --Supplemental Indenture, dated as of September 1, 1984, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-49).

4-B-56 --Supplemental Indenture, dated as of February 15, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-56).

4-B-58 --Supplemental Indenture, dated as of October 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1987, File No. 1-4928, as Exhibit 4-B-58).

4-B-60 --Supplemental Indenture, dated as of March 1, 1990, supplementing said Mortgage (filed with Form 10-K the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-60).

AGE>

EXHIBIT
NUMBER

4-B-62 --Supplemental Indenture, dated as of May 15, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-62).

4-B-63 --Supplemental Indenture, dated as of March 1, 1991, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-63).

4-B-64 --Supplemental Indenture, dated as of July 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-64).

4-B-65 --Supplemental Indenture, dated as of December 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-65).

4-B-66 --Supplemental Indenture, dated as of March 1, 1992, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1991, File No. 1-4928, as Exhibit 4-B-66).

4-B-67 --Supplemental Indenture, dated as of June 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-67).

4-B-68 --Supplemental Indenture, dated as of July 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-68).

4-B-69 --Supplemental Indenture, dated as of September 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-53308, effective November 24, 1992, as Exhibit 4-B-69).

4-B-70 --Supplemental Indenture, dated as of February 1, 1993, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, as Exhibit 4-B-70).

4-B-71 --Supplemental Indenture, dated as of March 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-59448, effective March 17, 1993, as Exhibit 4-B-71).

4-B-72 --Supplemental Indenture, dated as of April 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-72).

4-B-73 --Supplemental Indenture, dated as of May 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-73).

4-B-74 --Supplemental Indenture, dated as of June 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-74).

4-B-75 --Supplemental Indenture, dated as of July 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-75).

4-B-76 --Supplemental Indenture, dated as of August 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-76).

4-B-77 --Supplemental Indenture, dated as of August 20, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-77).

4-B-78 --Supplemental Indenture, dated as of May 1, 1994, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1994, File No. 1-4928, as Exhibit 4-B-78).

4-B-79 --Supplemental Indenture, dated as of November 1, 1994, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1994, File No. 1-4928, as Exhibit 4-B-79).

4-B-80 --Supplemental Indenture, dated as of August 1, 1995, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1995, File No. 1-4928, as Exhibit 4-B-80).

4-C --Instrument of Resignation, Appointment and Acceptance among Duke Power Company, Morgan Guaranty Trust Company of New York, as Trustee, and Chemical Bank, as Successor Trustee, dated as of August 30, 1994 (filed with Form 10-K for the year ended December 31, 1994, File No. 1-4928, as Exhibit 4-C).

10-A --Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).

10-B --Agreement, dated August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).

10-C --Agreement, dated October 14, 1980 between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

10-D --Agreement, dated October 14, 1980 between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).

10-E+ --Employees' Stock Ownership Plan.

10-F++ --Employee Incentive Plan.

10-G++ --1993 Executive Long-Term Incentive Plan.

10-H+ --Supplemental Security Plan.

10-I+ --Stock Purchase-Savings Program for Employees.

10-J+ --Employees' Retirement Plan.

10-K+ --Supplemental Retirement Plan.

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EXHIBIT NUMBER

10-L+ --Compensation Deferral Plan.

10-M+ --Compensation Deferral Plan for Outside Directors.

10-N+ --Retirement Plan for Outside Directors.

10-O+ --Supplementary Defined Contribution Plan for Employees.

10-P+ --Directors' Charitable Giving Program.

10-Q+ --Vacation Banking Plan.

10-R+ --Estate Conservation Plan.

10-S+ --Supplemental Insurance Plan.

10-T+ --Group Life Insurance Plan.

10-U+ --Stock Ownership Plan for Nonemployee Directors.

10-V+++ --Executive Short-Term Incentive Plan.

10-W+++ --Executive Long-Term Incentive Plan.

*10-X --Retirement Savings Plan.
*10-Y --Retirement Cash Balance Plan.
*10-Z --Executive Savings Plan.
*10-AA --Executive Cash Balance Plan.
*10-BB --Directors' Savings Plan.
*12 --Computation of Ratio of Earnings to Fixed Charges.
*23 --Consent of Independent Auditors.
*24(a) --Power of attorney authorizing Ellen T. Ruff and others to sign the annual report on behalf of the registrant and certain of its directors and officers.
*24(b) --Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.
*27 --Financial Data Schedule.
</TABLE>

+ Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, under the same exhibit number as listed herein.
++ Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1993, File No. 1-4928, under the same exhibit number as listed herein.
+++ Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1994, File No. 1-4928, under the same exhibit number as listed herein.

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EXHIBIT NO. 10-X
DUKE POWER COMPANY
RETIREMENT SAVINGS PLAN
(As Amended to January 1, 1997)

ARTICLE I. PURPOSE

Duke Power Company adopted the Duke Power Company Stock Purchase-Savings Program for Employees as of July 1, 1959, to provide an opportunity for employees to become shareholders of Duke Power Company ("Duke") and to encourage them to save on a regular basis by setting aside part of their earnings. The name of the Plan was changed to the Duke Power Company Retirement Savings Plan effective as of January 1, 1997. The Plan also has been adopted by Crescent Resources, Inc. ("Crescent"), DE&S Northwest, Inc. ("DE&S Northwest"), ıke Energy Corp. ("Duke Energy"), Duke Engineering & Services, Inc. ("Duke gineering"), Intera, Inc. ("Intera") and Nantahala Power and Light Company Nantahala"). The Plan is a profit sharing plan intended to satisfy the

requirements of section 401(a) of the Code as well as the guidelines set forth in section 404(c) of the Employee Retirement Income Security Act and the regulations thereunder.

The primary Plan provisions set forth herein are effective on and after January 1, 1997, except where an earlier or later date is specified. Employees of Nantahala Power and Light Company and Employees who on January 1, 1997, are covered by a collective bargaining agreement applicable to a collective bargaining unit which has not adopted the Plan as restated on January 1, 1997, shall continue to participate based upon the terms and conditions of the Plan in the form that it existed on December 31, 1996, a copy of which is attached to and made a part of this Plan as Appendix B. Notwithstanding the foregoing, when necessary to comply with federal laws and regulations, the provisions of the January 1, 1997 document shall be applied in lieu of the corresponding provisions of Appendix B; including without limitation Section 2.27, Sections 4.7-4.13(d), Article XIII and Article XIV.

ARTICLE II. DEFINITIONS

Wherever used herein, a pronoun or adjective in the masculine gender includes the feminine gender, the singular includes the plural, and the following terms have the following meanings unless a different meaning is clearly required by the context:

2.1 Actual Deferral Percentage: The ratio (expressed as a percentage) of Deferrals and Additional Deferrals on behalf of an Eligible Employee for the Plan Year to the Eligible Employee's Compensation for the Plan Year. The Actual Deferral Percentage of an Eligible Employee who does not make a Deferral or Additional Deferral is zero.

2.2 Additional Contributions: Eligible Earnings which an Eligible Employee could elect to contribute to the Plan by payroll deduction in Plan Years ending prior to November 1, 1991.

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2.3 Additional Deferrals: Eligible Earnings which an Eligible Employee elects to defer in accordance with section 4.2.

2.4 Adjustment Factor: The cost of living factor prescribed by the Secretary of the Treasury under section 415(d) of the Code for years beginning after December 31, 1987, as applied to such items and in such manner as the Secretary shall provide, but subject to the limitations of section 401(a)(17)(B) for Plan Years commencing after December 31, 1993.

2.5 Affiliated Employer: Any corporation which is a member of a controlled group of corporations (as defined in section 414(b) of the Code) which includes the Employer; any trade or business (whether or not incorporated) which is under common control (as defined in section 414(c) of the Code) with the Employer; any organization (whether or not incorporated) which is a member of an affiliated service group (as defined in section 414(m) of the Code) which includes the Employer; and any other entity required to be aggregated with the

Employer pursuant to regulations under section 414(o) of the Code.

2.6 Average Actual Deferral Percentage: The average (expressed as a percentage) of the Actual Deferral Percentages of the Eligible Employees in a group.

2.7 Average Contribution Percentage: The average (expressed as a percentage) of the Contribution Percentages of the Eligible Employees in a group.

2.8 Break in Service: A 12-consecutive month period during which an Employee does not have more than 500 Hours of Service with the Employer. The computation period described in Section 2.38 for measuring a Year of Service for eligibility purposes shall be used in determining a Break in Service.

2.9 Code: The Internal Revenue Code of 1986, as amended from time to time.

2.10 Committee: The Duke Power Company Stock Purchase-Savings Program Committee, which is the administrator of the Plan.

2.11 Compensation: Compensation shall mean (except as otherwise defined in Article XV) all of each Eligible Employee's compensation as described in section 1.415-2(d)(2) of the regulations, but excluding those items described in section 1.415-2(d)(3) of the regulations, received during the Plan Year by the Eligible Employee from the Employer, including amounts that are not currently includible in the Employee's gross income by reason of application of sections 125 or 402(a)(8) of the Code. The annual compensation of each Eligible Employee taken into account under the Plan for any Plan Year commencing after 1988 but before 1994 shall not exceed $200,000, as increased by the Adjustment Factor. The annual compensation of each Eligible Employee taken into account under the Plan for any Plan Year commencing after 1993 shall not exceed $150,000, as increased by the Adjustment Factor.

2.12 Contribution Percentage: The ratio (expressed as a percentage) of the sum of Employee contributions, Matching Contributions and Qualified Matching Contributions (to the extent not taken into account for the Actual Deferral Percentage test) under the Plan on behalf of

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the Eligible Employee for the Plan Year to the Eligible Employee's Compensation for the Plan Year.

2.13 Deferrals: Eligible Earnings which an Eligible Employee elects to defer in accordance with section 4.1.

2.14 Determination Date: The last day of each Plan Year.

2.15 Direct Rollover: A Direct Rollover is a payment by the Plan to the

Eligible Retirement Plan specified by the Distributee.

2.16 Distributee: A Distributee includes an Employee or former ployee. In addition, the Employee's or former employee's surviving spouse and e Employee's or former employee's spouse or former spouse who is the alternate payee under a qualified domestic relations order, as defined in section 414(p) of the Code, are Distributees with regard to the interest of the spouse or former spouse.

2.17 Duke Power Company Common Stock Fund: A Fund established under the Plan which will be invested primarily in the common stock of Duke Power Company plus a small percentage of cash. Participants within the Diversified Option may direct that all or a part of their Deferrals and Additional Deferrals, if any, be invested in this fund and all Matching Contributions for such Participants shall be initially invested in this fund.

2.18 Eligible Earnings: Eligible Earnings shall mean, for all Participants, all amounts received for services actually rendered in the course of employment with the Employer maintaining the Plan to the extent that such amounts are includible in the Participant's gross income as wages required to be reported under Code Sections 6041, 6051 and 6052 (Box 1 of Form W-2), without regard to limits on wages under Code Section 3401, such as the exemption for agricultural labor. Eligible Earnings shall also include any amount which is contributed by the Employer pursuant to a salary reduction agreement and which is not includible in the gross income of the Participant under Code Sections 125 or 401(k). However, Eligible Earnings shall not include expense reimbursements and allowances, cash or noncash fringe benefits, moving expenses, the receipt of mpensation previously deferred, severance pay, pay for unused vacation, cellence awards, welfare benefits, or long-term incentive payments (incentives attributable to multi-year performance periods for which no incentive is earned or paid until the end of the multi-year period). Incentive pay, including that attributable to participation in equity awards, that is paid to employees of Crescent Resources, Inc. will not constitute Eligible Earnings unless it is paid from the Crescent Resources Employee Goals Program. Notwithstanding the foregoing, individually determined incentive pay as distinguished from group incentive pay, that is paid to any individual employed by Crescent Resources Inc. shall be counted as Eligible Earnings to the extent such incentive pay does not exceed twenty percent of the individual's base pay determined as of the time the payment is made. Incentive pay that is payable to certain officers of Crescent Resources, who on January 1, 1983 first participated in an incentive compensation arrangement which was implemented on that date, and incentive pay that is payable to any officer who participated in such arrangement by employment agreement executed on January 1, 1983, shall not be counted as Eligible Earnings even if less than 20 percent of Base Pay.

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Earnings of a Participant in excess of the amount authorized pursuant Code Section 401(a)(17)($150,000 for 1996) for any Plan Year or any portion a Plan Year shall not be recognized; provided that the greatest amount authorized for Plan Years before 1994 shall be used retroactively to the extent

permitted by the Code.

2.19 Eligible Employee: An Employee who has attained age 18; satisfied participation requirements of Article III; is not a leased employee within the meaning of section 414(n)(2) of the Code; and is employed by an Employer listed on Appendix A. An Employee who is a nonresident alien (within the meaning of Section 7701(b)(1)(B) of the Code) and who receives no earned income (within the meaning of section 911(d)(2) of the Code) from the Employer that constitutes income from sources within the United States (within the meaning of Section 861(a)(3) of the Code) shall not be eligible to participate in the Program. Employees who on January 1, 1997, are covered by a collective bargaining agreement applicable to a collective bargaining unit which has not adopted this Plan, shall be ineligible to participate in this Plan as restated effective January 1, 1997, but shall instead continue to participate in the Plan as it existed on December 31, 1996, a copy of which is attached as Appendix B. Effective as soon as practicable following the ratification of a collective bargaining agreement which specifically adopts this Plan as restated on January 1, 1997, such Employees shall commence participation in the restated version of this Plan. Employees of Nantahala shall also participate in the Plan based upon the provisions set forth in Appendix B until Nantahala adopts the Plan as restated on January 1, 1997.

2.20 Eligible Retirement Plan: A plan defined in section 402(c)(8)(B) of the Code; however, in the case of an Eligible Rollover Distribution to the surviving spouse, an Eligible Retirement Plan is a plan described in subsection (i) or (ii) of section 402(c)(8)(B) of the Code.

2.21 Eligible Rollover Distribution: An Eligible Rollover Distribution any distribution of all or any portion of the balance to the credit of the Distributee, except that an Eligible Rollover Distribution does not include: any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) made for the life (or life expectancy) of the Distributee or the joint lives (or life expectancies) of the Distributee and the Distributee's designated beneficiary, or for a specified period of ten years or more; any distribution to the extent such distribution is required under section 401(a)(9) of the Code; and the portion of any distribution that is not includible in gross income (determined without regard to the exclusion for net unrealized appreciation with respect to employer securities).

2.22 Employee: An individual employed by an Affiliated Employer including a leased employee within the meaning of section 414(n)(2) of the Code. Notwithstanding the foregoing, if such leased employees constitute less than twenty (20) percent of the Affiliated Employer's Nonhighly Compensated work force within the meaning of section 414(n)(5)(C)(ii) of the Code, the term "Employee" shall not include those leased employees covered by a plan described in section 414(n)(5)(B) of the Code.

2.23 Employer: Duke Power Company, a North Carolina corporation, and those Affiliated Employers which have adopted the Plan as listed on Appendix A.

2.24 Excess Aggregate Contributions: With respect to any Plan Year, the gregate Contribution Percentage amounts actually paid over to the Trust on nalf of Highly Compensated Employees for the Plan Year, over the maximum amount of such contributions permitted under section 4.11.

2.25 Excess Deferrals: With respect to any Plan Year, the aggregate amount of Deferrals and Additional Deferrals actually paid over to the Trust on behalf of Highly Compensated Employees for such Plan Year, over the maximum amount of such contributions permitted under section 4.7.

2.26 Fund: Any of the funds, including the Duke Power Company Common Stock Fund, established under the Plan for investment of Participants' Accounts within the Diversified Option. The Committee shall have the discretion to establish and terminate such funds as it shall deem appropriate both on a prospective basis and with respect to existing Investment Accounts.

2.27 Highly Compensated Employee: The term "Highly Compensated Employee" shall include highly compensated active employees and highly compensated former employees. A highly compensated active employee includes any Employee who performs service for an Affiliated Employer during the determination year and who, during the preceding year: (i) received Compensation from the Employer in excess of $80,000 (as adjusted by the Adjustment Factor) and was a member of the top-paid group for such year, or (ii) was a 5-percent owner at any time during the determination year or the preceding year. An Employee is in the top-paid group of Employees for any year if such Employee is the group consisting of the top 20 percent of the Employees when ranked on e basis of Compensation paid during such year. An Employee is a 5-percent owner for any year if such Employee owns or is considered as owning (within the meaning of section 318 of the Code) more than 5 percent of the outstanding stock where the Employer is a corporation, or if the employer is not a corporation any person who owns more than 5 percent of the capital or profits interest. For this purpose, the determination year shall be the Plan Year. The preceding year shall be the twelve-month period immediately preceding the determination year.

A highly compensated former employee includes any Employee who separated from service (or was deemed to have separated) prior to the determination year, performs no service for the Employer during the determination year, and was a highly compensated active employee for either the separation year or any determination year ending on or after the Employee's 55th birthday, based upon the applicable definition of a highly compensated active employee for such earlier separation year or determination year.

The determination of who is a Highly Compensated Employee, including the determinations of the number and identity of Employees in the top-paid group and the Compensation that is considered, will be made in accordance with section 414(q) of the Code and the regulations thereunder.

2.28 Hour of Service: Each hour for which an Employee is directly or indirectly paid, or entitled to payment, by an Affiliated Employer (including e Duke/Fluor Daniel partnership).

ours in which duties are performed shall be credited to the computation period in which the duties are performed. Hours in which no duties are performed but for which payment is made for reasons such as vacations, holidays, illness and hours for which back pay is awarded or agreed to shall be credited to the computation period to which the payment pertains. No duplicate credit shall be given on account of an award or agreement for back pay. Hours of Service shall be calculated and credited pursuant to section 2530.200b-2 of the Department of Labor Regulations.

2.29 Matching Contribution: Any contribution to the Plan made by the Employer for the Plan Year and allocated to a Participant's account by reason of the Participant's Deferrals.

2.30 Nonhighly Compensated Employee: An Employee of the Affiliated Employer who is not a Highly Compensated Employee.

2.31 Participant: Either an Eligible Employee who has met the participation requirements of Article III and currently is making contributions under the Plan or an individual who is not making contributions currently but to whose account there are investments under the Plan.

2.32 Plan: The Duke Power Company Retirement Savings Plan, the Plan set forth herein, as amended from time to time.

2.33 Plan Manager: The person appointed by the Committee to have primary responsibility for management of regular operations of the Plan.

2.34 Plan Year: The calendar year.

2.35 Qualified Matching Contribution: Matching Contributions which are subject to the distribution and nonforfeitability requirements under section 401(k) of the Code when made.

2.36 Rollover Account: The account established pursuant to section 17.4 to accept and hold rollover contributions under Article XVII.

2.37 Termination of Employment: The ending of the employment relationship between the Affiliated Employer and Employee for a cause other than death. No Termination of Employment results when an Employee takes a leave of absence authorized by the Affiliated Employer under the Affiliated Employer's established and nondiscriminatory personnel practices.

2.38 Trustee; Trust: The Trustee provided for in Article XVIII and the Trust that the Trustee is to administer.

2.39 Valuation Date: With respect to the Basic Option, the Valuation Date shall be the last day of each calendar month. With respect to the versified Option, the Valuation Date shall be each day during which shares of ck are traded on the New York Stock Exchange, or such other date or dates hich may be established by the Committee.

2.40 Year of Service: A one-year period during which the Employee has least 1,000 Hours of Service. The initial computation period shall commence the first day an Employee is

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entitled to be credited with an Hour of Service. Succeeding computation periods shall be Plan Years, beginning with the Plan Year which includes the first anniversary of the employment commencement date.

ARTICLE III. ELECTION OF PARTICIPATION

3.1 General Rule for Participation: An individual who is an Eligible Employee may elect in accordance with provisions of section 3.2 to commence participation after the individual has completed a Year of Service or was an Employee, throughout the three immediately preceding calendar months. Participation shall commence as soon as practicable following both the satisfaction of the service requirements and the filing of an election to participate under Section 3.2.

3.2 Election to Participate: An election to participate shall be made by written notice delivered to the Employer or by electronic communication on or before the day on which participation is to commence. The notice shall include a salary deferral election as permitted under sections 4.1 and 4.2. Eligible ployees shall be notified of their eligibility in ample time for them to be le to commence participation at the earliest possible date.

3.3 An Eligible Employee who was a Participant on December 31, 1996, shall continue to participate in accordance with the Plan provisions set forth herein.

3.4 Immediate Participation: An Eligible Employee may elect in accordance with the provisions of section 3.3 to commence participation on the date of being reemployed, if the individual had at any time satisfied the participation requirements of Article III.

3.5 Break in Service: A Break in Service shall have the following consequences:

(a) Employee with Vested Benefit: The pre-break and post-break Years of Service of an Employee who had satisfied the requirements of Article XI for a vested benefit before commencement of a Break in Service shall be added together for the purpose of determining his or her rights and benefits.

(b) Employee with no Vested Benefit: The pre-break vesting and participating Years of Service of an Employee who had not earned a vested benefit before commencement of a Break in Service shall be lost unless (a) the Employee acquires at least 1,000 Hours of Service in a calendar year which llows the Break in Service and (b) the number of consecutive one-year Breaks Service is less than the number of earlier Years of Service or five, whichever is greater.

(c) Solely for purposes of determining whether a Break in Service for participation and vesting purposes has occurred, an individual who is absent from work for maternity or paternity reasons shall receive credit for the Hours of Service which would otherwise have been credited to such individual but for such absence, or in any case in which such hours cannot be determined, eight hours of service per day of such absence. For purposes of this paragraph, an absence from work for maternity or paternity reasons means an absence (i) by reason of the pregnancy of the

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individual, (ii) by reason of a birth of a child of the individual, (iii) by reason of the placement of a child with the individual in connection with the adoption of such child by such individual, or (iv) for purposes of caring for such child for a period beginning immediately following such birth or placement. The Hours of Service credited under this paragraph shall be credited (i) in the computation period in which the absence begins if the crediting is necessary to prevent a Break in Service in that period, or (ii) in all other cases, in the following computation period

ARTICLE IV. EMPLOYEE DEFERRALS AND ADDITIONAL DEFERRALS

4.1 Deferrals: An Eligible Employee may defer, in increments one percent, a percentage of Eligible Earnings to the Plan. The minimum Deferral shall be one percent of Eligible Earnings and the maximum Deferral shall be six percent of Eligible Earnings. The Participant's Eligible Earnings for the Plan Year shall be reduced by an amount equal to the Deferrals authorized by the Participant, and the Employer shall contribute to the Trust for each Plan Year an amount equal to the Deferrals elected by the Participant. Any such Employer contribution shall be credited to the Deferral account of the Participant and shall be subject to the restrictions on distributions set forth in Article IX.

4.2 Additional Deferrals. An Eligible Employee may authorize Additional Deferrals, which are not matched by the Employer, in increments of one percent of Eligible Earnings. The minimum Additional Deferral shall be one percent of Eligible Earnings, and the maximum Additional Deferral shall be four percent of Eligible Earnings. The Participant's Eligible Earnings for the Plan Year shall be reduced by an amount equal to the Additional Deferrals authorized by the Participant, and the Employer shall contribute to the Trust for each Plan Year an amount equal to the Additional Deferrals elected by the Participant. Any such Employer contribution shall be credited to the Additional Deferral account of the Participant and shall be subject to the restrictions on distributions set forth in Article IX.

4.3 Maximum Amount of Deferrals and Additional Deferrals: No Participant shall be permitted to elect Deferrals and Additional Deferrals under this Plan and any other similar program for a calendar year in excess of $7,000, multiplied by the Adjustment Factor. Notwithstanding a Participant's election under section 4.1 or section 4.2, the Plan Manager shall on a prospective basis limit the Deferrals or Additional Deferrals elected by some or all Highly Compensated Employees to prevent a violation of the Average Actual Deferral

Percentage test described in section 4.7 or the Average Contribution Percentage test described in section 4.11. The Plan Manager shall adjust the Additional Deferrals of Highly Compensated Employees, beginning with the Highly Compensated Employee(s) with the highest amount of Additional Deferrals, in a manner consistent with the method described in section 401(k)(8)(C) of the Code, prior to adjusting the Deferrals of any Highly Compensated Employee. If it then becomes necessary to reduce the Deferrals of any Highly Compensated Employee, such reduction shall also be conducted in accordance with section 401(k)(8)(C) of the Code. The Plan Manager shall give written notice to each Participant whose Deferrals or Additional Deferrals will be reduced or eliminated pursuant to this section.

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4.4 Changes in Contributions: A Participant may change the percentage of his Deferrals or Additional Deferrals as of the first day of the Plan Year immediately following the date the Employer receives a notice of change.

4.5 Suspension of Contributions: A Participant may suspend Deferrals or Additional Deferrals by giving written or electronic notice before the start of the first payroll period affected by the suspension. A Participant whose Deferrals or Additional Deferrals have been suspended may resume contributions by executing a new payroll authorization. The authorization shall be effective as of the first day of the Plan Year next following the date the Employer receives written or electronic notice.

4.6 Rounding of Amounts: Amounts of payroll reductions may be rounded in a manner determined by the Plan Manager for the purposes of facilitating administration of the Plan.

4.7 Average Actual Deferral Percentage: The Average Actual Deferral Percentage for Highly Compensated Employees for the Plan Year and the Average Actual Deferral Percentage for Nonhighly Compensated Employees for the preceding Plan Year must satisfy one of the following tests:

(a) The Average Actual Deferral Percentage for Eligible Employees who are Highly Compensated Employees for the Plan Year shall not exceed the Average Actual Deferral Percentage for Eligible Employees who are Nonhighly Compensated Employees for the Plan Year multiplied by 1.25; or

(b) The Average Actual Deferral Percentage for the Plan Year for Eligible Employees who are Highly Compensated Employees for the Plan Year shall not exceed the Average Actual Deferral Percentage for the Plan Year for Eligible Employees who are Nonhighly Compensated Employees for the Plan Year multiplied by 2.0, provided that the Average Actual Deferral Percentage for the Plan Year for Eligible Employees who are Highly Compensated Employees does not exceed the Average Actual Deferral Percentage for the Plan Year for Eligible Employees who are Nonhighly Compensated Employees by more than two (2) percentage points or such lesser amount as the Secretary of the Treasury shall prescribe to prevent the multiple use of this alternative limitation with respect to any Highly Compensated Employee.

4.8 Special Rules:

4.8(a) The Actual Deferral Percentage for the Plan Year for any Eligible Employee who is a Highly Compensated Employee for the Plan Year and who ligible to have Deferrals or Additional Deferrals allocated to his or her count under two or more arrangements described in section 401(k) of the Code at are maintained by the Employer shall be determined as if such Deferrals and Additional Deferrals were made under a single arrangement.

4.8(b) The determination and treatment of the Deferrals, Additional Deferrals, and Actual Deferral Percentage of any Eligible Employee shall satisfy such other requirements as may be prescribed by the Secretary of the Treasury.

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4.9 Distribution of Excess Deferrals: Notwithstanding any other provision of the Plan, Excess Deferrals, plus any income and minus any loss allocable thereto, shall be distributed no later than the last day of each Plan Year to Participants to whose accounts Deferrals and Additional Deferrals were allocated for the preceding Plan Year. Excess Deferrals shall be treated as annual additions under the Plan. Excess Deferrals shall be determined and distributed in accordance with Section 401(k)(8)(C) of the Code beginning with the Highly Compensated Employee(s) with the highest amount of Additional Deferrals and Deferrals.

4.10 Determination of Income or Loss:

4.10(a) The Excess Deferrals shall be adjusted for income or loss. The ome or loss allocable to Excess Deferrals shall be determined (i) by multiplying the income or loss allocable to the Participant's Deferrals and Additional Deferrals for the Plan Year by a fraction, the numerator of which is the Excess Deferral on behalf of the Participant for the preceding Plan Year and the denominator of which is the sum of the Participant's account balances attributable to Deferrals and Additional Deferrals on the last day of the preceding Plan Year, or (ii) by any other method authorized by the Code or regulations thereunder.

4.10(b) Accounting for Excess Deferrals: Amounts distributed under this section shall first be treated as distributions from the Participant's Additional Deferral account and shall be treated as distributed from the Participant's Deferral account only to the extent such Excess Deferrals exceed the balance in the Participant's Additional Deferral account.

4.11 Contribution Percentage:

4.11(a) The Average Contribution Percentage for the Plan Year for Eligible Employees who are Highly Compensated Employees for the Plan Year shall not exceed the Average Contribution Percentage for the Plan Year for Eligible Employees who are Nonhighly Compensated Employees for the Plan Year multiplied by 1.25; or

4.11(b) The Average Contribution Percentage for the Plan Year for gible Employees who are Highly Compensated Employees for the Plan Year shall t exceed the Average Contribution Percentage for the Plan Year for Eligible

Employees who are Nonhighly Compensated Employees for the Plan Year multiplied by two (2), provided that the Average Contribution Percentage for the Plan Year for Eligible Employees who are Highly Compensated Employees does not exceed the erage Contribution Percentage for the Plan Year for Eligible Employees who are nhighly Compensated Employees by more than two (2) percentage points or such esser amount as the Secretary of the Treasury shall prescribe to prevent the multiple use of this alternative limitation with respect to any Highly Compensated Employee.

4.12 Special Rules:

4.12(a) Multiple Use: If one or more Highly Compensated Employees participate in both a cash or deferred arrangement and a plan subject to the Average Contribution Percentage test maintained by the employer and the sum of the Average Deferral Percentage and Average Contribution Percentage of those Highly Compensated Employees subject to either or both tests

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exceeds the aggregate limit, then the Average Contribution Percentage of those Highly Compensated Employees who also participate in a cash or deferred arrangement will be reduced (beginning with such Highly Compensated Employee whose Average Contribution Percentage is the highest) so that the limit is not exceeded. The amount by which each Highly Compensated Employee's Contribution Percentage Amounts is reduced shall be treated as an Excess Aggregate Contribution. The Average Deferral Percentage and Average Contribution ercentage of the Highly Compensated Employees are determined after any rrections required to meet the Average Deferral Percentage and Average ontribution Percentage tests. Multiple use does not occur if either the Average Deferral Percentage or Average Contribution Percentage of the Highly Compensated Employees does not exceed 1.25 multiplied by the Average Deferral Percentage and Average Contribution Percentage of the Nonhighly Compensated Employees.

4.12(b) The Contribution Percentage for any Eligible Employee who is a Highly Compensated Employee for the Plan Year and who is eligible to make employee contributions, or to have Matching Contributions allocated to his account under two or more plans described in section 401(a) of the Code, or arrangements described in section 401(k) of the Code, that are maintained by the Employer, shall be determined as if the total of such employee contributions and Matching Contributions was made under a single plan.

4.12(c) In the event that this Plan satisfies the requirements of sections 401(m), 401(a)(4) or 410(b) of the Code only if aggregated with one or more other plans, or if one or more other plans satisfy such sections of the Code only if aggregated with this Plan, then this section shall be applied by determining the Contribution Percentages of Eligible Employees as if all such plans were a single plan. For plan years beginning after December 31, 1989, plans may be aggregated in order to satisfy Section 401(m) of the Code only if they have the same plan year.

4.12(d) The determination and treatment of the Contribution Percentage any Eligible Employee shall satisfy such other requirements as may be escribed by the Secretary of the Treasury.

4.13 Distribution of Excess Aggregate Contributions:

4.13(a) General Rule: Notwithstanding any other provision of this Plan, cess Aggregate Contributions, plus any income and minus any loss allocable ıereto, shall be distributed (or, if forfeitable, forfeited) no later than the last day of each Plan Year to Participants to whose accounts such Excess Aggregate Contributions were allocated for the preceding Plan Year. Excess Aggregate Contributions shall be treated as annual additions under the Plan. Any distribution of the Excess Aggregate Contributions for any Plan Year shall be made to Highly Compensated Employees on the basis of the amount of contribution on behalf of, or by, each such Highly Compensated Employee.

4.13(b) Determination of Income or Loss: The Excess Aggregate Contributions shall be adjusted for income or loss. The income or loss allocable to Excess Aggregate Contributions shall be determined (i) by multiplying the income or loss allocable to the Participant's employee contributions, Matching Contributions and Qualified Matching Contribution Account (if any, and if all amounts therein are not used in the Actual Deferral Percentage test) for the Plan Year by a

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fraction, the numerator of which is the Excess Aggregate Contributions on behalf of the Participant for the preceding Plan Year and the denominator of which is the sum of the Participant's account balance attributable to Contribution rcentage amounts on the last day of the preceding Plan Year, or (ii) by any ier method authorized by the Code or regulations thereunder.

4.13(c) Treatment of Forfeitures: Forfeitures of Excess Aggregate Contributions shall serve to reduce Employer contributions. Amounts forfeited by Highly Compensated Employees under this section shall be treated as annual additions under the Plan.

4.13(d) Accounting for Excess Aggregate Contributions: Excess Aggregate Contributions shall be forfeited on a pro rata basis from the Participant's employee contribution account, Matching Contributions account and Qualified Matching Contribution Account. The determination of the Excess Aggregate Contributions shall be made after first determining the Excess Elective Deferrals, and then determining the Excess Contributions.

4.14 Military Service: Notwithstanding any provisions of the Plan to the contrary, contributions, benefits and service credit with respect to qualified military service will be provided in accordance with Section 414(u)(4) of the Code.

ARTICLE V. EMPLOYER CONTRIBUTIONS - MATCHING

5.1 Amount of Matching Contributions: Subject to the limitation in ction 5.2, each Employer shall contribute out of current or accumulated nings an amount equal to one hundred percent of the first three percent of Deferrals made by its Employees under provisions of section 4.1 and an

amount equal to fifty percent of the next three percent of Deferrals made by its Employees, except that the Matching Contribution attributable to Excess Deferrals must be forfeited. If an Employer does not have current or accumulated nings that are adequate for this purpose, the other Employers shall ıtribute on its behalf in proportion to the sum of the current and accumulated earnings of each.

5.2 Forfeiture of Matching Contributions: Duke Power Company common stock and uninvested cash which represent Employer contributions or earnings thereon that are forfeited by Participants who receive distributions, make withdrawals or are attributable to Excess Deferrals shall be applied to restore forfeitures in accordance with provisions of Article XIV or to reduce subsequent contributions of the Employer, or, if the Plan should be terminated, any amount not so applied shall be credited ratably to the accounts of all Participants at the time of termination. There shall be no forfeiture of Matching Contributions by a Participant who has at least one Hour of Service on or after April 1, 1993, with respect to any distribution or withdrawal made on or after that date.

5.3 Maturity of Matching Contributions: Matching Contributions which are not forfeitable will mature at the end of the 24th month following the month for which the matching contributions are posted to the Participant's account. Upon the expiration of the 24-month period the Matching Contributions may be distributed pursuant to Article IX, and transferred into

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vestment options other than the Duke Power Company Common Stock Fund, except he case of accounts within the Basic Option which must remain invested in Duke Power Company common stock.

ARTICLE VI. PLAN INVESTMENTS

6.1 General: A Participant shall have the choice of investing both pretax and after-tax accounts in either the Basic Option as described in section 6.2 or the Diversified Option as described in section 6.3. A Participant who holds United States Savings Bonds in his or her account, shall be restricted to investing both pretax and after-tax accounts in the Basic Option until such time that he or she liquidates his or her investment in United States Savings Bonds. A Participant who does not hold any investment in United States Savings Bonds in his or her account shall be restricted to investing in the Diversified Option.

6.2 Basic Option: Each Participant within the Basic Option shall have all of his or her Deferrals and Additional Deferrals invested in the Duke Power Company Common Stock Fund. This investment election shall remain in effect throughout such Plan Year, unless the Participant elects in accordance with procedures established by the Plan Manager to transfer into the Diversified Option by choosing to liquidate all United States Savings Bonds held in his account. All Matching Contributions for Participants in the Basic Option shall be invested in Duke Power Company Common Stock Fund.

6.2(a) Earnings on Investments within the Basic Option: Earnings, gains d losses on the Duke Power Company Common Stock Fund shall be allocated as

under Section 6.3(a). Interest on United States Savings Bonds shall be invested in, or reflected in the redemption value of, such United States Savings Bonds.

6.2(b) Uninvested Cash within the Basic Option: Any uninvested cash in account of a Participant at the end of a Plan Year shall be carried over to the next Plan Year, if the Employee continues as a Participant, and then invested.

6.3 Diversified Option: Each Participant within the Diversified Option shall direct whether his Deferrals and Additional Deferrals, if any, shall be invested in the Duke Power Company Common Stock Fund or in any other Fund offered as an investment option within the Diversified Option. At such time and in such manner as the Plan Manager shall prescribe, each Participant may file with the Plan Manager such Participant's direction with respect to what percentage, if any, of future Deferrals and Additional Deferrals shall be invested in any one or more of the Funds or in the Duke Power Company Common Stock Fund. The percentages so specified by the Participant shall be stated in one percent increments (ten percent increments prior to April 1, 1997). Each such election (or change of election) shall be effective as soon as practicable, but no later than five business days, after the date on which the Plan Manager receives actual notice of the election. If by a date designated by the Plan Manager prior to the allocation of contributions and/or forfeitures there shall not be in effect a valid investment election from a Participant, any amounts allocated to such participant's account shall be invested entirely in the Duke Power Company Common Stock Fund. A Participant shall be eligible to file one election

(or change of election) in any calendar month with respect to existing accounts and one such change per calendar month with respect to the investment of future Deferrals or Additional deferrals during any month prior to April 1, 1997. On and after April 1, 1997, a Participant may change investment options without limitation. For this purpose an election (or change of election) shall be defined to mean any investment notification received by the Plan Manager in any one day, regardless of the number of investment elections made on such day. All Matching Contributions made on behalf of Participants within the Diversified Option shall be allocated to the Duke Power Company Common Stock Fund and such investments, including earnings thereon, must remain in the Duke Power Company Common Stock Fund until the end of the 24th month following the month for which the Matching Contributions are posted to the account.

6.3(a) Amounts that are to be invested in the Duke Power Company Common Stock Fund, whether on account of Deferrals, Additional Deferrals or Matching Contributions, shall be transferred to the Trustee for investment or invested in Duke Power Company common stock by Duke Power Company for transfer to the Trustee. Trust earnings shall be invested by the Trustee in the Fund. Purchase of Duke Power Company common stock may be by open market purchase, by private purchase or from Duke Power Company by subscription or purchase, whichever may be directed by the Plan Manager. Investment by subscription or purchase from Duke Power Company shall be at the daily closing market price on the New York Stock Exchange on the date of subscription or purchase. While the Duke Power

Company Common Stock Fund will consist primarily of Duke Power Company common stock, it will also contain a small cash balance sufficient to cover transfers, withdrawals, and similar Plan transactions. The Plan Manager shall from time to time instruct the Trustee with respect to the percentage of the Duke Power Company Common Stock Fund which shall be held in the form of cash or cash equivalents.

6.3(b) Accounts and Funds held within the Diversified Option shall be valued as of each Valuation Date. Earnings, gains, and losses (realized or unrealized) for each Fund shall be allocated to the portion ("subaccount") of a Participant's Account maintained with respect to that Fund, in the same ratio that the value of the subaccount (determined as of the Valuation Date) bears to the sum of the values of all participant's subaccounts maintained with respect to the Funds. For the purpose of determining the ratio, the value of the subaccount shall be the value of the subaccount as of the last previous Valuation Date, adjusted for contributions, reallocated forfeitures, loans and loan repayments, interfund transfers, distributions, withdrawals, and expenses.

ARTICLE VII. INVESTMENT ELECTIONS; TRANSFERS

7.1 Elections: At such time and in such manner as the Plan Manager shall prescribe, each Participant shall file with the Plan Manager notice of his or her direction with respect to any election granted to such Participant under the terms of the Plan. The Plan Manager may establish procedures to accept Participant direction by telephone or other electronic means.

7.2 Transfers among Options. A Participant's subaccounts within the Basic Option shall be transferred to the Diversified Option, as soon as practicable following the date on which the Participant elects to liquidate all United States Savings Bonds held in his or her account. Cash

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held within the Basic Option shall be transferred into a Fund selected by the Participant, or in the absence of such direction, such cash shall be invested in a money market mutual fund offered as a Fund within the Diversified Option. No transfers shall be permitted from the Diversified Option into the Basic Option.

7.3 Transfers within the Basic Option: A Participant shall not be entitled to transfer amounts held in one subaccount within the Basic Option to any other subaccount within the Basic Option.

7.4 Transfers within the Diversified Option: A Participant shall be entitled to transfer amounts held within the Diversified Option between Funds. Transfers shall be allowed only in increments of one percent of the balance of any Fund determined as of the date on which the transfer is made (ten percent for transfers prior to April 1, 1997). No transfer shall be allowable at any time from Matching Contributions which have not matured. The Plan Manager shall direct the Trustee to transfer moneys or other property from one Fund to another and as may be necessary to carry out the Participant's transfer transactions in accordance with uniform rules established by the Plan Manager. Transfers will be

allowable on any day on which the New York Stock Exchange is open for trading.

7.5 Restrictions on Transfers: Notwithstanding any other provision of Plan, the Plan Manager may establish procedures to delay or cancel any nsaction directed by a Participant to the extent such transaction may result in a violation of federal securities laws.

ARTICLE VIII. INVESTMENT ACCOUNTS

8.1 Separate Accounts: Separate accounts for each Participant shall reflect the form of investment, the Option (Basic or Diversified) in which he has investments, and the source of the original investment (Participant Deferrals, Additional Deferrals, and Matching Contributions). The Deferral account may be consolidated with the Additional Deferral account and the Rollover Account upon the maturity of Matching Contributions attributable to the Deferrals. Original investments and income thereon shall be reflected separately in the account. Income shall be applied to the Plan Year of the original investment to which it relates.

8.2 Account Information: United States Savings Bonds shall be accounted for on a cost basis. Funds held within the Diversified Option shall be accounted for on the unit accounting basis.

ARTICLE IX. DISTRIBUTION

9.1 Distribution Before Termination of Employment:

(a) A Participant may elect any time during the Plan Year to receive distributions from his accounts in the following order. Except as provided in sections 9.1(c) and (d), distribution will not be made from an account until the account previously listed has been exhausted.

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1. Employee after-tax accounts
2. Employer contribution accounts including matured Matching Contribution accounts

(b) Matching Contribution accounts will mature at the end of the 24th month following the month for which the contributions are posted to the accounts.

(c) A Participant may request a cash distribution from his or her Deferral account, Additional Deferral account and Rollover Account if he or she suffers a hardship or is at least age 59 1/2. A hardship will be determined by the Plan Manager to exist if the distribution is necessary in light of immediate and heavy financial needs of the Participant, and if funds to alleviate such financial needs are not reasonably available from other resources of the

Participant. A distribution due to a hardship must not exceed the lesser of (1) the amount necessary to alleviate the hardship, or (2) the balance in the Participant's Deferral, Additional Deferral, and Rollover Accounts, exclusive of any income allocable to such accounts after December 31, 1988.

Any distribution on and after April 1, 1989, will be deemed to be on account of an immediate and heavy financial need of the Participant if the distribution is on account of:

1. Medical expenses described in section 213(d) of the Code incurred by the Participant, the Participant's spouse, or any dependents of the Participant (as defined in section 152 of the Code);

2. Purchase (excluding mortgage payments) of a principal residence of the Participant;

3. Payment of tuition and related educational fees for the next 12 months of post-secondary education for the Participant, his or her spouse, children, or dependents;

4. The need to prevent the eviction of the Participant from his or her principal residence or foreclosure on the mortgage on the Participant's principal residence; or

5. Any additional needs specified by the Commissioner of the Internal Revenue Service through the publication of revenue rulings, notices, and other documents of general applicability.

Any distribution on and after April 1, 1989, will be treated as necessary to satisfy a financial need if the Plan Manager reasonably relies upon the Participant's written representation, unless the Plan Manager has actual knowledge to the contrary, that the need cannot be relieved:

1. Through reimbursement or compensation by insurance or otherwise;

2. By reasonable liquidation of the Participant's assets (including those of his or her spouse or minor children that are reasonably available), to the extent such liquidation would not itself cause an immediate and heavy financial need;

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3. By cessation of Deferrals or Additional Deferrals under the Plan; or

4. By distributions or nontaxable (at the time of the loan) loans from plans maintained by the Employer or any other employer, or by borrowing from commercial sources on reasonable commercial terms.

(d) Distributions under section 9(c) will be made in the following order:

1. Employee after-tax accounts

2. Employer contribution accounts including matured Matching Contribution accounts

3. Rollover Account

4. Deferral account

5. Additional Deferral account

9.2 Distribution on Termination of Employment: If a Participant terminates employment, he or she may elect to receive in a single distribution the entire balance in his or her accounts. If a Participant does not elect an immediate distribution under this section, he or she may defer the distribution until any date prior to the first day of April of the calendar year immediately following the calendar year in which the Participant attains age 70 1/2.

9.3 Distributions on Death: A distribution occasioned by the death of a Participant shall be made to the surviving spouse of the Participant. If there is no surviving spouse, or if the spouse has consented in writing properly witnessed by a Plan representative or notary public, the distribution shall be made to the specific beneficiary or beneficiaries designated by the Participant. If there is no surviving spouse, and if no valid designation has been made or a beneficiary does not survive the Participant, the distribution shall be made to the Participant's estate. A Participant may file with the Plan Manager a written designation of beneficiary. Such a designation may be changed or revoked by a written notice filed with the Plan Manager; however, such a change must be properly consented to by the Participant's spouse, if the spouse is not named as Beneficiary. A distribution shall be made as soon as practicable after the death of the Participant and in any event within 60 days after the close of the Plan Year in which that occasion falls, except that a beneficiary of a deceased Participant may elect no later than 60 days after the death of the Participant, that a distribution be delayed until either:

(a) A date that follows the occasion for the distribution by not more than one year, or, if later,

(b) a date in the distributee's taxable year in which there will be lump-sum distribution, as defined in section 402(e)(4)(A) of the Internal Revenue Code, from another qualified plan maintained by the Employer.

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9.4 Eligible Rollover Distributions: Notwithstanding any provision of the Plan to the contrary that would otherwise limit a Distributee's election under this section, a Distributee may elect, at the time and in the manner prescribed by the Plan Manager, to have any portion of an Eligible Rollover Distribution paid directly to an Eligible Retirement Plan specified by the Distributee in a Direct Rollover, except that only one such Eligible Retirement Plan may be designated for any single Eligible Rollover Distribution.

9.5 Amount of Distribution: A distribution from a Participant's account shall include all assets in the account, except that if the distribution is the

result of a Termination of Employment, assets that represent Matching Contributions that are not vested under Article XIII and earnings thereon shall not be distributed.

9.6 Form of Distribution: Distribution of amounts invested in the Duke Power Company Common Stock Fund shall be made in whole shares of Duke Power Company common stock. Distribution of amounts invested in United States Savings Bonds shall be made in United States Savings Bonds. Distribution of amounts invested in any Fund other than the Duke Power Company Common Stock Fund shall be made in cash. Notwithstanding the foregoing, a distribution shall be made in cash to the extent it represents (a) uninvested cash, (b) cash for fractional shares of Duke Power Company common stock, or (c) cash in lieu of whole shares of Duke Power Company common stock provided such a cash distribution is elected by a Participant from his or her account in the Duke Power Company Common Stock Fund.

9.7 Fractional Shares: No fractional shares of Duke Power Company common stock shall be distributed. A fractional share that is the last item in an account shall be paid in cash. Cash settlements for fractional shares shall be based on fair market value at the time of settlement.

9.8 Required Minimum Distributions: Effective for Plan Years beginning on and after the effective date of section 401(a)(9) of the Code and regulations thereunder, and notwithstanding any other provisions of the Plan which may authorize a later distribution, all distributions shall satisfy the following requirements:

(a) With respect to the interest of an active Participant, distribution the Participant's interest must commence no later than April 1 of the calendar year following the later of the calendar year in which he or she attains age 70 1/2 or, except in the case of a Participant who is a five-percent owner (as defined in section 416 of the Code), the taxable year in which he or she retires. Distribution of the Participant's entire interest shall be made over a period not extending beyond the life expectancy of the Participant, or if married the joint life and last survivor expectancy of the Participant and his or her spouse, provided the spouse is the designated beneficiary.

(b) With respect to the interest of a deceased Participant, the entire interest of the Participant must be distributed no later than December 31 of the calendar year which contains the fifth anniversary of the date of the Participant's death.

(c) The requirements of this section shall not be construed to expand the period of time by which a distribution must be made where a shorter period of time is specified elsewhere in this document.

9.9 Consent for Cash Out of Distributions: No distribution of a vested benefit with a present value which exceeds $3,500 shall be made without the written or electronic consent of the Participant. Effective on and after April 1997, vested benefits with a present value of less than $3,500 shall be

distributed to any Participant who is no longer employed by an Affiliated Employer.

9.10 Waiver of Notice: No distribution shall be made to any participant less such participant has received the notice required by section 1.411(a)-11(c) of the Income Tax Regulations no less than 30 days and no more than 90 days before the date of the distribution. If a distribution is one to which sections 401(a)(11) and 417 of the Internal Revenue Code do not apply, such distribution may commence less than 30 days after the notice required under section 1.411(a)-11(c) of the Income Tax Regulations is given, provided that:

(a) the plan administrator clearly informs the participant that the Participant has a right to a period of at least 30 days after receiving the notice to consider the decision of whether or not to elect a distribution (and, if applicable, a particular distribution option), and

(b) the participant, after receiving the notice, affirmatively elects a distribution.

9.11 Qualified Domestic Relations Order: Notwithstanding any other provision of this Plan, a portion of all of the account balance of any Participant, including Deferrals, Additional Deferrals, Matching Contributions and Rollover Accounts shall be paid to an alternate payee to the extent required by a Qualified Domestic Relations Order that satisfies the requirements of section 414(p) of the Code. A distribution to an alternate payee from a Participant's Deferral and Additional Deferral accounts may be made prior to the date on which the Participant attains age 59 1/2 pursuant to a Qualified Domestic Relations Order which satisfies section 414(p) of the Code. Unmatured Matching Contributions shall not be distributable to an alternate payee until they become distributable to the Participant. If a separate account is established for an alternate payee, he or she may elect to withdraw the entire balance in one distribution, which shall be made no later than April 1 of the calendar year following the calendar year in which he or she attains age 70 1/2.

ARTICLE X. LOANS TO PARTICIPANTS

10.1 Amount of Loan: A Participant may request a loan from his Rollover Account, Deferral account and Additional Deferral account, except that no loans may be made to a Participant in the Basic Option. The Plan Manager upon request, shall lend to such participant from his Rollover Account, Deferral account and Additional Deferral account in that order an amount which when added to the Participant's outstanding loans from any other plan maintained by the Employer is not in excess of the lesser of:

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(a) $50,000, reduced by the excess (if any) of

1. the highest outstanding balance of loans from all plans maintained by the Employer during the one-year period

ending on the day before the date on which such loan was made, over

2. the outstanding balance of loans from all plans maintained by the Employer on the date on which the loan was made; or

(b) fifty percent (50%) of the value of the Participant's accounts which are vested under the rules of Article XI, such value to be determined as of the Valuation Date coinciding with or immediately preceding the origination date of the loan. If between the date on which a Participant makes application for a loan and the date on which the loan is actually made there is a decline in value of the Participant's Deferral, Additional Deferral and Rollover accounts such that there are insufficient funds in such accounts from which to make a loan in the requested amount, then the loan proceeds shall be taken from other accounts in the order set forth in section 9.1(a). Notwithstanding the foregoing, no loan shall be in an amount which would exceed the limitations set forth in this section 10.1.

10.2 Terms of Loan: In addition to such rules and regulations as the Committee may adopt, all loans shall comply with the following terms and conditions:

(a) An application for a loan by Participant shall be made in writing or by electronic communication to the Plan Manager.

(b) The period of repayment for any loan except as set forth in subsection (c) below, shall be arrived at by mutual agreement between the Plan manager and the borrower, but such period in no event shall exceed five (5) years.

(c) Notwithstanding the above, the period of repayment for any loan used to acquire any dwelling unit which within a reasonable time is to be used as the principal residence of the Participant in no event shall exceed ten (10) years.

(d) Each loan shall be made against collateral being the assignment of fifty percent (50%) of the borrower's right, title and vested interest in and to his or her vested account balances supported by the borrower's collateral promissory note for the amount of the loan, including interest, payable to the order of the Trustee.

(e) Each loan shall bear interest at the rate which would be charged by Wachovia Bank of North Carolina, N.A., on similar commercial loans.

(f) The minimum loan amount shall be $500.

(g) Repayment of loans shall be made by payroll deduction or as specified in the loan agreement; however, except as may be provided by regulations issued by the Department of the Treasury, substantially level amortization of a loan is required with payments not less frequently

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than quarterly. Since loan repayment must be made by payroll deduction, no loan shall be made to an alternate payee under a Qualified Domestic Relations Order to a terminated Participant.

(h) A Participant may have no more than two loans (one loan prior to April 1, 1997) from this Plan outstanding at a time.

(i) Assets in the Participant's accounts shall be converted to cash, and then the amount of such loan shall be removed from the accounts and transferred to a special loan account in the name of the borrowing Participant. As of each Valuation Date following the making of the loan and until the loan is repaid, all payments on the loan, including interest, shall be reallocated from the Participant's loan account and reinvested within either the Basic Option or the Diversified Option depending upon the Option in which the Participant has investments at the time of the repayment. Repayments shall be allocated among investment alternatives within an Option on a proportionate basis in accordance with the Participant's election with respect to the investment of current Deferrals. If the Participant has not elected current Deferrals, all repayments shall be allocated to the Duke Power Company Common Stock Fund.

(j) Upon termination of employment a Participant must repay the outstanding balance of the loan plus interest due in full.

(k) In the event of default, foreclosure on the note and attachment of security will not occur until a distributable event occurs under the Plan.

(l) A reasonable origination fee in an amount determined from time to time by the Plan Administrator may be charged to any Participant who makes a loan under the Plan. The origination fee will be withheld from the proceeds of the loan.

10.3 Loans to Former Employees: Loans shall be made available only to former Employees who are also "parties-in-interest" as defined in section 3(14) of the Employee's Retirement Income Security Act of 1974.

10.4. Military Service: Loan repayments will be suspended under this Plan as permitted under Section 414(u)(4) of the Code.

ARTICLE XI. VESTING

A Participant's Deferral and Additional Deferral accounts shall be fully vested at all times. Matching Contributions made in accordance with Article V and earnings thereon shall be fully vested with respect to any Participant with at least one Hour of Service on or after April 1, 1993. Matching Contributions made on behalf of a Participant who does not have at least one Hour of Service on or after April 1, 1993, shall vest in accordance with the provisions of this Plan as in effect on and before March 31, 1993, as set forth in Appendix C, except that any Participant who elected to terminate employment pursuant to the Limited Period Separation Opportunity sponsored by the Employer during February 1993, shall be fully vested in all Matching Contributions.

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ARTICLE XII. FORFEITURES

There shall be no forfeiture with respect to any Participant who has at least one Hour of Service on or after April 1, 1993, except to the extent that Matching Contributions attributable to Excess Deferrals or Excess Aggregate Contributions are required by law to be forfeited. Any forfeiture occurring under provisions of the Plan as in effect prior to April 1, 1993, shall be subject to the forfeiture and repayment rules set forth in the Plan on the date of the event giving rise to the forfeiture.

ARTICLE XIII LIMITATION OF CONTRIBUTIONS AND BENEFITS

13.1(a) Annual Addition: "Annual Addition" shall mean all employee and employer contribution amounts allocated to a Participant's account during the Limitation Year that constitutes:

1. Employer contributions,
2. Employee contributions,
3. Forfeitures, and
4. Amounts described in sections 415(1)(1) and 419 (A)(d)(2) of the Code.

13.1(b) Maximum Annual Addition: The maximum Annual Addition that may be contributed or allocated to a Participant's account under the Plan for any Limitation Year shall not exceed the lesser of:

1. the Defined Contribution Dollar Limitation, or
2. 25 percent of the Participant's compensation, within the meaning of section 415(c)(3) of the Code for the Limitation Year.

13.1(c) Special Rules: The compensation limitation referred to in section 15.1(b)(ii) shall not apply to:

1. Any contribution for medical benefits (within the meaning of section 419A(f)(2) of the Code) after separation from service which is otherwise treated as an Annual Addition, or
2. Any amount otherwise treated as an Annual Addition under section 415(1)(1) of the Code.

13.1(d) Defined Contribution Dollar Limitation: For purposes of section 15.1(b), "Defined Contribution Dollar Limitation" shall mean $30,000 or, if greater, one-fourth of the defined benefit dollar limitation set forth in section 415(b)(1) of the Code as in effect for the Limitation Year.

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13.1(e) Recomputation Not Required: The Annual Addition for any Limitation Year beginning before January 1, 1987, shall not be recomputed to at all Employee Contributions as an Annual Addition.

13.1(f) Excess Annual Additions: If the Annual Additions made to this Plan on behalf of any Participant exceed the maximum, the Employer shall treat the excess amount of such Annual Additions as follows:

1. So much of the Participant's contributions, including Deferrals and Additional Deferrals, which cause the Participant's accounts to exceed the maximum Annual Additions shall be returned to the Participant;

2. So much of any Employer contribution allocated to the Participant's accounts in excess of the maximum Annual Additions shall be used to reduce the Employer's contribution for the following Plan Year (and succeeding Plan Years as necessary) for the Participant if that Participant is covered by the Plan as of the end of the following Plan Year. If such Participant is not covered by the Plan for the following Plan Year, the excess Annual Additions shall be allocated to the accounts of other Participants.

A Participant may not choose to defer an amount that would cause the Annual Additions in this Plan alone to exceed the maximum allowed.

13.2(a) Combined Plan Limitations on Contributions and Benefits: If an Employee is or was a Participant in one or more defined benefit plans and one or more defined contribution plans maintained by the Employer, the sum of the Defined Benefit Plan Fraction and the Defined Contribution Plan Fraction shall not exceed 1.0 for any Limitation Year which begins before January 1, 2000. If the sum of the Defined Benefit Plan Fraction or the Defined Contribution Plan Fraction shall exceed 1.0 in any year for any Participant in this Plan, the Employer shall reduce the Plan benefits in such manner that the limitations of section 415(e) of the Internal Revenue Code will be satisfied without reduction, or with minimum reduction, of Employer or Employee contributions to defined contribution plans of the Employer.

13.2(b) Defined Benefit Plan Fraction: For the purpose of this Article XIII, the term "Defined Benefit Plan Fraction" for any year shall mean a fraction, the numerator of which is the projected annual benefit payable to a Participant as of the close of the then current year under all plans maintained by this Employer and the denominator of which is the lessor of:

1. The product of 1.25 multiplied by the maximum dollar limitation for the Plan Year concerned as provided under Code section 415, or
2. The product of 1.4 multiplied by the applicable percentage of compensation limit as defined for this purpose under Code section 415.

13.2(c) Defined Contribution Plan Fraction: The term "Defined

Contribution Plan Fraction" for any year shall mean a fraction the numerator of which is the aggregate amount of Annual Additions made to a Participant's accounts under all plans maintained by this Employer as

of the close of the then current year and the denominator of which is the sum of the lesser of the following amounts determined for such year and for each prior Year of Service with the Employer:

1. The product of 1.25 multiplied by the maximum dollar limitation for the Plan Year concerned as provided under Code section 415, or

2. The product of 1.4 multiplied by the applicable percentage of compensation limit as defined for this purpose under Code section 415.

13.2(d) Adjustment of Defined Contribution Plan Fraction: If the Plan satisfied the applicable requirements of section 415 of the Code as in effect for all Limitation Years beginning before January 1, 1987, an amount shall be subtracted from the numerator of the Defined Contribution Plan Fraction (not exceeding such numerator) as prescribed by the Secretary of the Treasury so that the sum of the Defined Benefit Plan Fraction and Defined Contribution Plan Fraction computed under section 415(e)(1) of the Code (as revised by this Article XIII) does not exceed 1.0 for such Limitation Year.

13.3 Compensation: For purposes of this Article XV, "Compensation" will be determined under Section 2.11 Amounts that are not currently includible in the Participant's gross income by reason of the application of section 125 or section 402(a)(8) of the Code shall not be counted except in Limitation Years beginning after December 31, 1997.

13.4 Limitation Year: For purposes of this Article XIII, "Limitation Year" shall mean the calendar year.

13.5 Transitional Rule: At the election of the Plan Manager, with respect to any year ending after December 31, 1982, the amount taken into account in determining the defined contribution plan fraction with respect to each Participant for all years ending before January 1, 1983, shall be an amount equal to the product of (a) and (b), where

(a) is the Defined Contribution Plan Fraction in effect for the year ending in 1982, and

(b) is the Transition Fraction.

Transition Fraction means a fraction, the numerator of which is the lesser of $51,874, or 1.4 multiplied by 25 percent of the Compensation of the Participant the year ending in 1981 and, the denominator of which is the lesser of $41,500 or 25 percent of the Compensation of the Participant for the year ending

in 1981. If the plan is a Top-Heavy Plan, as defined by the Tax Equity and Fiscal Responsibility Act of 1982, then $41,500 shall be substituted for $51,874 in the numerator of the Transition Fraction.

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ARTICLE XIV. TOP HEAVY PROVISIONS

14.1 Definitions. If the Plan is or becomes top-heavy in any Plan Year beginning after December 31, 1983, the provisions of this Article will supersede any conflicting provisions in the Plan and the following definitions will apply:

(a) Key employee: Any Employee or former employee (and the beneficiaries of such Employee) who at any time during the determination period was an officer of the Employer if such individual's annual compensation exceeds 50 percent of the dollar limitation under section 415(b)(1)(A) of the Code, an owner (or considered an owner under section 318 of the Code) or one of the ten largest interests in the Employer if such individual's Compensation exceeds 100 percent of the dollar limitation under section 415(c)(1)(A) of the Code, a five-percent owner of the Employer, or a one-percent owner of the Employer who has an annual compensation of more than $150,000. Annual compensation means Compensation as defined in section 2.11. The determination period is the Plan Year containing the determination date and the four preceding Plan Years. The determination of who is a key employee will be made in accordance with section 416(i)(1) of the Code and the regulations thereunder.

(b) Top-heavy plan: For any Plan Year beginning after December 31, 83, this Plan is top-heavy if any of the following conditions exists:

1. If the top-heavy ratio for this Plan exceeds 60 percent and this Plan is not part of any required aggregation group or permissive aggregation group of plans.
2. If this Plan is a part of a required aggregation group of plans but not part of a permissive aggregation group and the top-heavy ratio for the group of plans exceeds 60 percent.
3. If this Plan is a part of a required aggregation group and part of a permissive aggregation group of plans and the top-heavy ratio for the permissive aggregation group exceeds 60 percent.

(c) Top-heavy ratio:

1. If the Employer maintains one or more defined contribution plans (including any simplified employee pension plan) and the Employer has not maintained any defined benefit plan which during the five-year period ending on the determination date(s) has or has had accrued benefits, the top-heavy ratio for this Plan alone or for the required or permissive aggregation group as appropriate is a fraction, the numerator of which is the sum of the account balances of all key employees as of the

determination date(s) (including any part of any account balance distributed in the five-year period ending on the determination date(s)), and the denominator of which is the sum of all account balances (including any part of any account balance distributed in the five-year period ending on the determination date(s), both computed in accordance with section 416 of the Code and the regulations thereunder. Both the numerator and denominator of the top-heavy ratio are increased to reflect any contribution not actually made as of the determination date, but which is

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required to be taken into account on that date under section 416 of the Code and the regulations thereunder.

2. If the Employer maintains one or more defined contribution plans (including any simplified employee pension plan) and the Employer maintains or has maintained one or more defined benefit plans which during the five-year period ending on the determination date(s) has or has had any accrued benefits, the top-heavy ratio for any required or permissive aggregation group as appropriate is a fraction, the numerator of which is the sum of account balances under the aggregated defined contribution plan or plans for all key employees, determined in accordance with (1) above, and the present value of accrued benefits under the aggregated defined benefit plan or plans for all key employees as of the determination date(s), and the denominator of which is the sum of the account balances under the aggregated defined contribution plan or plans for all Participants, determined in accordance with (1) above, and the present value of accrued benefits under the defined benefit plan or plans for all Participants as of the determination date(s), all determined in accordance with section 416 of the Code and the regulations thereunder. The accrued benefits under a defined benefit plan in both the numerator and denominator of the top-heavy ratio are increased for any distribution of an accrued benefit made in the five-year period ending on the determination date.

3. For purposes of (1) and (2) above the value of account balances and the present value of accrued benefits will be determined as of the most recent valuation date that falls within or ends with the 12-month period ending on the determination date, except as provided in section 416 of the Code and the regulations thereunder for the first and second plan years of a defined benefit plan. The account balances and accrued benefits of a Participant (i) who is not a key employee but who was a key employee in a prior year, or (ii) who has not been credited with at least one

hour of service with any employer maintaining the Plan at any time during the five-year period ending on the determination date will be disregarded. The calculation of the top-heavy ratio, and the extent to which distributions, rollovers, and transfers are taken into account will be made in accordance with section 416 of the Code and the regulations thereunder. Deductible employee contributions will not be taken into account for purposes of computing the top-heavy ratio. When aggregating plans the value of account balances and accrued benefits will be calculated with reference to the determination dates that fall within the same calendar year.

The accrued benefit of a Participant other than a key employee shall be determined under (a) the method, if any, that uniformly applies for accrual purposes under all defined benefit plans maintained by the Employer, or (b) if there is no such method, as if such benefit accrued not more rapidly than the slowest accrual rate permitted under the fractional rule of section 411(b)(1)(C) of the Code.

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(d) Permissive aggregation group: The required aggregation group of plans plus any other plan or plans of the Employer which, when considered as a group with the required aggregation group, would continue to satisfy the requirements of sections 401(a)(4) or 410 of the Code.

(e) Required aggregation group: (1) Each qualified plan of the Employer in which at least one key employee participates or participated at any time during the determination period (regardless of whether the plan has terminated), and (2) any other qualified plan of the Employer which enables a plan described in (1) to meet the requirements of sections 401(a)(4) or 410 of the Code.

(f) Determination date: For any Plan Year subsequent to the first Plan Year, the last day of the preceding Plan Year. For the first Plan Year of the Plan, the last day of that year.

(g) Valuation date: For purposes of computing the top-heavy ratio, the valuation date shall be December 31 of each year.

(h) For purposes of establishing present value to compute the top-heavy ratio, any benefit shall be discounted only for mortality and interest based on the following:

Interest rate: 8% Mortality table: 1984 Unisex Pension Mortality Table

14.2 Minimum allocation

(a) Except as otherwise provided in (c) and (d) below, the employer contributions and forfeitures allocated on behalf of any Participant who is not a key employee shall not be less than the lesser of three percent of such Participant's Compensation or in the case where the Employer has no defined

benefit plan which designates this Plan to satisfy section 401 of the Code, the largest percentage of employer contributions and forfeitures, as a percentage of key employee's Compensation, as limited by section 401(a)(17) of the Code, allocated on behalf of any key employee for that year. The minimum allocation is determined without regard to any Social Security contribution. This minimum allocation shall be made even though, under other Plan provisions, the Participant would not otherwise be entitled to receive an allocation, or would have received a lesser allocation for the year because of (i) the Participant's failure to complete 1,000 hours of service (of any equivalent provided in the Plan), or (ii) the Participant's failure to make mandatory employee contributions to the Plan, or (iii) Compensation less than a stated amount.

(b) For purposes of computing the minimum allocation, Compensation shall mean Compensation as defined in section 2.11 as limited by section 401(a)(17) of the Code.

(c) The provision in (a) above shall not apply to any Participant who was not employed by the Employer on the last day of the Plan Year.

(d) The provision in (a) above shall not apply to any Participant to the extent the Participant is covered under a top-heavy defined benefit plan. Each Participant covered by both a

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top-heavy defined benefit plan and a top-heavy defined contribution plan shall receive the minimum benefit provided under the defined benefit plan.

14.3 Minimum vesting schedules. For any Plan Year in which this Plan is top-heavy, the nonforfeitable interest of each Employee in his or her account balance attributable to employer contributions shall be determined on the basis of 100% vesting after three years of service. The minimum vesting schedule applies to all benefits within the meaning of section 411(a)(7) of the Code except those attributable to employee contributions, including benefits accrued before the effective date of section 416 and benefits accrued before the Plan became top-heavy. Further, no decrease in a Participant's nonforfeitable percentage may occur in the event the Plan's status as top-heavy changes for any Plan Year. However, this section does not apply to the account balances of any Employee who does not have an hour of service after the Plan has initially become top-heavy and such Employee's account balance attributable to employer contributions and forfeitures will be determined without regard to this section. If the vesting schedule under the plans shifts in or out of the above schedule for any plan year because of the Plan's top-heavy status, such shift is an amendment to the vesting schedule and each Participant with at least three years of service may elect to have the nonforfeitable percentage under the Plan computed without regard to the change.

14.4 Effect on section 415 limitations: If the Employer maintains both a defined contribution plan and a defined benefit plan with an Employee who participates, or could participate, in both plans, then for purposes of computing the defined contribution fraction and defined benefit fraction described in section 13.2 (b) and (c), the dollar limitation of sections

415(b)(1)(A) and 415(c)(1)(A) shall be multiplied by 1.0 in lieu of 1.25, unless:

(a) Either (1) the benefits under each plan satisfy the minimum requirements of section 416(h)(A)(ii)(I) and (II); or (2) the Plan benefits satisfy standards otherwise developed by the Secretary of the Treasury; and

(b) The Plan would not be top heavy if 90 percent were substituted for 60 percent in paragraph 14.1 (b) above.

This Section shall be applicable for any Limitation Year which begins after December 31, 1998.

ARTICLE XV. VOTING OF STOCK

A Participant may instruct the Trustee, in accordance with procedures approved by the Committee, how to vote shares of Duke Power Company common stock or units of the Duke Power Company Common Stock Fund credited to the Employee's accounts. The Trustee shall vote the shares with respect to which it has received instructions in accordance with the instructions. It shall vote other shares held by it under the Plan in its capacity as Trustee.

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ARTICLE XVI. ADMINISTRATION

16.1 Plan Administrator: The Plan shall be administered by the Duke Power Company Employees' Stock Purchase-Savings Program Committee or by a successor individual or body designated by the Board of Directors of Duke Power Company.

16.2 Power and Duties of the Committee: Except where prohibited by law, the Committee retains the discretionary authority to determine eligibility for benefits and to construe the terms of the Plan. The Committee shall have all such powers as may be necessary to discharge its duties hereunder, including, but not by way of limitation, the power to (a) interpret or construe the Plan, (b) determine all questions of eligibility, (c) determine the classification, status and rights of Employees, Participants and beneficiaries of Participants, (d) determine the amount, manner and time of any distribution hereunder, and (e) fix minimum periods of notice where notice is required, all in a manner not inconsistent with the terms of the Plan. All rules and decisions of the Committee shall be uniformly and consistently applied to all persons in similar circumstances. The Committee shall be entitled to rely upon certificates of the Employer and the Trustee as to information pertinent to any determination made pursuant to the Plan.

The Committee shall cause to be maintained such books of accounts, records and other data as may be necessary or advisable in its judgment for the purpose of the proper administration of the Plan. The Committee shall appoint a

Plan Manager who shall have primary responsibility for management of regular operations of the Plan and may appoint or employ such agents, attorneys and clerical assistants as it deems necessary.

The Committee shall direct the Trustee concerning all payments that shall be made from the Trust pursuant to the Plan.

The Committee shall by rule or regulation establish a claims procedure under which each claimant shall receive notice in writing in the event any claim for benefits under the Plan has been denied. The notice shall set forth the specific reasons for the denial. The claims procedure shall also provide an opportunity for full and fair review by the Committee of any denial of a claim.

If, in the Committee's judgment, any person to whom a distribution is due is lacking in capacity because of illness, accident or otherwise, the Committee may authorize the making of the distribution to any person or institution that in the Committee's judgment is responsible for caring for the person who is entitled to the distribution.

The Committee may act at a meeting or in writing without a meeting. It may adopt such rules and regulations as it deems desirable for the conduct of its affairs. Decisions by the Committee shall be made by the vote or assent of a majority of its members. The Committee shall have the power to assign or allocate any of its responsibilities among its members and to designate one or more persons (including persons who are not members of the Committee) to carry out its responsibilities.

Any action by the Committee on matters within its discretion shall be final and conclusive as to all interested persons.

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16.3 Plan Expenses: Expenses of administering the Plan shall be paid by the Employer to the extent such expenses are not paid by the Plan or charged directly to Plan Participants.

ARTICLE XVII. ROLLOVER CONTRIBUTIONS

17.1 Rollover of Funds from Other Plans. In the event that an individual

(a) becomes an Eligible Employee who meets the participation requirements of the Plan under Section 3.1 other than the service requirements, and

(b) shall have been a participant in an employer's plan described in Section 401(a) of the Code, the trust of which is exempt from tax under Section 501(a) of the Code, and

(c) received from such trust an Eligible Rollover Distribution, and

(d) such property consists of money, then, the Eligible Employee may on and after April 1, 1997, transfer any portion of the distribution greater than or equal to $500, to the extent that it does not exceed the amount referred to in subsection 402(c)(2) of the Code, to this Trust by Direct Rollover from such other plan or by transferring the distribution to the Trust on or before the sixtieth (60th) day after the day on which he received such property. Upon receipt by the Trust, such amount shall be credited to the Rollover Account established hereunder. The eligible Employee shall have a one-hundred percent (100%) vested and nonforfeitable right to all amounts credited to his Rollover Account as a result of such transfer.

17.2 Transfer of amount distributed from a rollover IRA.

(a) An Eligible Employee who has received a distribution meeting the requirements of Section 17.1, and who subsequently deposited such distribution in an individual retirement account, as defined in Section 408, in accordance with Code Section 408(d)(3)(A)(ii), may contribute part or all of a distribution from such account (the "transferred amount") to the trust provided the conditions set forth in (b) and (c) are satisfied.

(b) The transferred amount must be contributed to the Trust on or before the 60th day following the Eligible Employee's receipt of the amount from the individual retirement account.

(c) The distribution must consist of the entire amount in the individual retirement account, and must include no amount attributable to any source other than a qualified plan described in Code Section 401(a).

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17.3 Monitoring of rollovers.

(a) The Plan Administrator shall establish such procedures and require such information from transferring employees as it deems necessary to insure that amounts transferred under this Article XVII meet the requirements for tax-free rollovers established by such section and by the Code and Treasury regulations.

(b) No amount may be transferred under this Article XVII until approved by the Plan Administrator.

17.4 Treatment of transferred amount under the Plan.

(a) The Administrator will establish an account (the "Rollover

Account") for each Eligible Employee making a contribution described in Section 17.1 or 17.2 above. The transferred amount will be invested as directed by the Eligible Employee as if the Rollover Account were a Deferral or Additional Deferral account. Upon retirement, death, or other termination of employment, the Eligible Employee's rollover account shall be distributed to him in accordance with Article IX.

(b) Notwithstanding any provision of this Plan to the contrary, to the extent that any optional form of benefit under this Plan permits a distribution prior to the Eligible Employee's retirement, death, disability, or severance from employment, and prior to Plan termination, the optional form of benefit is not available with respect to benefits attributable to assets (including the post-transfer earnings thereon) and liabilities that are transferred, within the meaning of section 414(l) of the Internal Revenue Code, to this Plan from a money purchase pension plan qualified under section 401(a) of the Internal Revenue Code (other than any portion of those assets and liabilities attributable to voluntary employee contributions).

(c) The Eligible Employee will at all times have a fully vested and nonforfeitable interest in the amount credited to his Rollover Account.

(d) An Eligible Employee who contributes an amount to the Plan in accordance with this Article XVII will not become a Participant until he or she has satisfied the requirements of Article III. However, such an Eligible Employee will be treated as a Participant, with respect to his or her interest in Rollover Account, except that such a Participant may not receive either in-service withdrawals or loans until he or she has satisfied the general participation requirements set forth in Section 3.1.

ARTICLE XVIII. TRUSTEE

Duke Power Company, representing the Employer, shall enter into a trust agreement which shall provide, among other things, for a Trust to which all contributions shall be paid, and the Trustee shall have such rights, powers and duties as are set forth in the trust agreement. All assets of the Trust shall be held and invested in accordance with the provisions of the trust agreement and the Plan for the sole benefit of Participants and their beneficiaries. The Trustee

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shall be responsible solely for the investment and safekeeping of the assets of the Trust and shall have no responsibility for the operation or administration of the Plan. The Trustee shall have the authority to make distributions and to pay moneys to or on the order of the Committee upon requisition drawn upon the Trustee.

ARTICLE XIX. FIDUCIARY LIABILITIES

The Employer, Officers and Directors of the Employer, the Committee cluding the individual members thereof), the Trustee, the Plan Manager, and y person who is deemed to be a fiduciary under the Plan (these persons and ntities are referred to below as "they") shall not be liable for a breach of fiduciary responsibility of another fiduciary under the Plan except to the extent (a) they shall have participated knowingly in, or knowingly undertaken to conceal, an act or omission of such fiduciary, knowing such act or omission was a breach of such fiduciary's fiduciary responsibilities, (b) they shall have through a breach of their fiduciary responsibilities enabled such fiduciary to commit a breach of its fiduciary responsibilities, or (c) they shall have knowledge of a breach of fiduciary responsibilities by such fiduciary, unless they have made reasonable efforts to remedy the breach.

They also shall not be liable for the acts or omissions of any person or persons to whom any authority, power or responsibility has been allocated or who have been designated to carry out their responsibilities, except to the extent they shall have violated their fiduciary responsibilities with respect to such allocation or designation or would otherwise be liable under provisions of the immediately preceding paragraph.

The Committee, its individual members and other fiduciaries who are employed by the Employer shall be indemnified by the Employer or from proceeds under insurance policies purchased by the Employer against any and all liabilities arising by reason of any act or failure to act made in good faith pursuant to the provisions of the Plan, including expenses reasonably incurred the defense of any claim relating thereto.

ARTICLE XX. AMENDMENT OR TERMINATION

The Plan may be amended or terminated by action of the Management Committee of the Board of Directors of Duke Power Company, but no amendment or termination shall cause any of the assets of the Trust to be used for or be diverted to any purpose other than the exclusive benefit of Participants or their beneficiaries and no amendment may retroactively reduce a Participant's account. In the case of a termination, partial termination or a complete discontinuance of contributions to the Plan, all amounts credited to the accounts of Participants shall become nonforfeitable.

ARTICLE XXI. GENERAL PROVISIONS

21.1 Source of Distributions: Distributions under this Plan shall be made only out of the Trust. No persons shall have any rights under the Plan with respect to the Trust, or against the Trustee or the Employer, except as cifically provided for herein.

21.2 Inalienability of Benefits: Except as otherwise provided by law, no person shall have the right to assign, alienate, transfer, hypothecate or otherwise subject to lien an interest in or benefit under the Plan nor shall benefits under the Plan be subject to the claims of any creditor.

21.3 Merger or Consolidation: In case of a merger or consolidation with, or transfer of assets or liabilities to, any other plan, each Participant shall (if a termination immediately occurs) receive a benefit at least as large as that he would have been entitled to had the Plan been terminated immediately before the merger, consolidation or transfer.

21.4 No Right to Employment: The Plan confers no right upon any Employee to continue employment with an Employer company.

21.5 Controlling Law: The administration of the Plan shall be governed by the laws of the state of North Carolina, except to the extent preempted by the laws of the United States, and any persons or corporation who now are or later become parties to the Plan shall be deemed to consent to this provision.

21.6 Investment Risk: Each Participant assumes all investment risk connected with the Plan, including the selection of investment Funds and any changes in the market price of Duke Power Company common stock, United States Savings Bonds, or any units of the Funds offered under the Plan; the Committee retains the right to modify the investment options offered under the Plan at any time with respect to both existing account balances and future investments.

In witness whereof this plan has been executed by the Company, pursuant to action of the Management Committee of the Board of Directors on December 23, 1996.

ATTEST: DUKE POWER COMPANY

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Ellen T. Ruff W. H. Grigg
Secretary & Deputy General Counsel Chairman and Chief Executive Officer

APPENDIX A

Affiliated Employers which have been authorized to participate in the plan and have adopted the plan:

Crescent Resources, Inc.
Duke Engineering & Services, Inc.
DE&S Northwest, Inc.
Duke Energy Corp.
Nantahala Power and Light Company
Intera, Inc.

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APPENDIX B

Duke Power Company Stock Purchase-Savings Program as effective on December 31, 1996, which continues in effect for Employees of Nantahala Power and Light Company and for certain Employees covered by collective bargaining agreements as more fully described in Section 2.19.

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APPENDIX C

VESTING PROVISIONS APPLICABLE PRIOR TO APRIL 1, 1993

ARTICLE XII. VESTING

A Participant's Deferral, Additional Deferral, Regular Contribution and Additional Contribution accounts shall be fully vested at all times. Matching Contributions made in accordance with Article V and earnings thereon shall vest at the earliest of:

(a) With respect to a Participant with at least one Hour of Service on or after November 1, 1989, the completion by such Participant of at least five Years of Service with the Employer, whether or not consecutive. (In determining the Years of Service completed by a Participant in Plan Years ending prior to November 1, 1989, a Participant shall receive a year of service for each such prior Plan Year if the Participant was performing services on the last day of such prior Plan Year. Similarly, if the Participant was not performing services on the last day of such prior Plan Years, the Participant shall be treated as if one-year Break in Service occurred for such prior Plan Year.);

(b) The end of the second Plan Year following the Plan Year for which the contributions were made,

(c) death of the Participant,

(d) retirement under provisions of the Duke Power Company Employees' Retirement Plan or the Retirement Plans for Salaried and Hourly Employees of Nantahala Power and Light Company,

(e) a layoff because of lack of available work,

(f) Termination of Employment if a showing of hardship, as defined in section 10.1(d), is made to the satisfaction of the Plan Manger,

(g) the time of termination or partial termination of the Plan or a complete discontinuance of contributions,

(h) attainment by the Participant of age 65, and

(i) Involuntary Termination of Employment on account of the sale or other disposition by an Employer of substantially all of its operating assets or the sale or other disposition of all of the stock of an Employer to an entity not required to be aggregated under sections 414(b), (c), (m) or (o) of the Code.

Employer contributions made in accordance with Article VI or Article VII shall vest on the December 31 as of which eligibility for the contributions determined.

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<TYPE>EX-10
<SEQUENCE>3
<DESCRIPTION>EXHIBIT 10-Y
<TEXT>

Exhibit No. 10-Y

DUKE POWER COMPANY
RETIREMENT CASH BALANCE PLAN

Amended and Restated
fective January 1, 1997

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DUKE POWER COMPANY RETIREMENT CASH BALANCE PLAN

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DUKE POWER COMPANY RETIREMENT CASH BALANCE PLAN

As Amended and Restated
Effective January 1, 1997

PREAMBLE

Duke Power Company, a corporation organized under the laws of the state of North Carolina adopted the Duke Power Company Employee's Retirement Plan as of January 1, 1943, to provide retirement benefits for its employees. The Plan was later adopted by Crescent Resources, Inc., Duke Engineering & Services, Inc., Intera, Inc., Duke Energy Corp., and DE&S Northwest, Inc. to provide retirement benefits for their employees.

This Plan modifies and retains the program of benefits previously maintained and makes those changes necessary to comply with current law and incorporate additional benefit modifications. The terms and conditions of the Plan shall, except as otherwise specifically provided in this Plan and this Preamble, apply only to Participants who have not retired or terminated their employment with the Company as of January 1, 1997. Except as otherwise provided herein, the right to any benefits under the Plan, with respect to a Participant who retired or terminated employment with the Company prior to January 1, 1997, shall be determined in accordance with the terms of the Plan as in effect at his date of retirement or termination of employment. However, the Plan shall not apply to any collective bargaining unit until the Plan is implemented with respect to such collective bargaining unit. The terms and conditions of the Prior Plan shall remain in full force and effect for any Participant that is a member of a collective bargaining unit for whom benefits under the Prior Plan have been negotiated in good faith and for whom benefits under this Plan have not been implemented.

The Plan, as restated, is intended to continue the Plan as a retirement plan qualified under Code Section 401(a) and the separate Trust Agreement is intended to continue the Trust as tax-exempt under Code Section 501(a).

The purpose of this Plan is to provide Employees who qualify as Participants with retirement and incidental benefits from the assets of the Trust in addition to any other benefits such Participants may be entitled to receive under any other benefit program sponsored by the Company or under the federal Social Security Act.

The Company intends this Plan, in conjunction with the Trust Agreement, to meet all of the requirements of ERISA and the Code and the terms of this Plan shall be interpreted to comply with ERISA and the Code and all final regulations and formal rulings

issued under ERISA and the Code.

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ARTICLE 1

DEFINITIONS AND CONSTRUCTION

The following words and phrases shall have the meanings specified and set forth opposite such terms for purposes of this Plan:

1.1 Accrued Benefit shall mean, as of any date, the following amount:

(a) A Participant's Cash Balance Account described in Section 3.6. However, in no event will a Participant's Accrued Benefit be less than the Actuarial Value of his retirement benefit as of the date of adoption of this restated Plan, as determined pursuant to the provisions of the Prior Plan as in effect immediately prior to the Effective Date.

(b) If the Participant is a 1996 Terminated Participant, the Participant's Accrued Benefit shall be the sum of the Participant's Cash Balance Account and the Actuarial Value of the Participant's 1996 Plan Benefit, if any.

1.2 Active Participant shall mean an Employee who has become a Participant as provided in Section 2.1 and who

(a) is an Employee as of the date of reference, or

(b) terminated employment following his Disability Date and continues to suffer from a Total and Permanent Disability as of the date of reference, but not yet commenced distribution of benefits under the Plan.

However, an Active Participant shall not include an Employee who is receiving retirement disability benefits under the Duke Power Company Group Life Insurance Plan as of the Effective Date.

1.3 Actuarial Equivalent shall mean a benefit of equivalent value, as certified by the Actuary, computed on the basis of the following assumptions with respect to determinations made on and after January 1, 1997.

Mortality - the blended (50/50) 1983 Group Annuity Mortality Table.

Interest - 7%, compounded annually.

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Actuarial Value shall mean a benefit of equivalent value, as certified by the Actuary, of a Participant's benefit provided under the Plan, computed on and after January 1, 1997, on the basis of the following assumptions:

Mortality - the table described in Section 417(e) of the Code, which for 1997 is the blended (50/50) 1983 Group Annuity Mortality Table.

Interest - the annual yield on 30-year Treasury securities determined as the average for the month of November prior to the beginning of the Plan Year during which the Annuity Starting Date begins, determined in accordance with Section 417(e) of the Code.

1.5 Actuary shall mean a person who has been enrolled by the Joint Board for the Enrollment of Actuaries, or a firm of actuaries at least one of whose members is a person who has been so enrolled. The Actuary shall be designated by the Plan Administrator.

Affiliate shall mean an organization which is a member of the same controlled group of organizations as the Corporation, as defined in Code Section 414(b), (c), (m), and (o).

1.7 Attained Age shall mean, unless clearly indicated to the contrary, the age of an Employee or Participant on such date, determined in whole and partial years.

1.8 Annuity Starting Date shall mean the first day of the first month with respect to which an amount is received as a benefit under the Plan.

1.9 Beneficiary shall mean any person or persons (or a trust) designated by a Participant in such form and manner as the Retirement Plan Committee shall prescribe to receive a Death Benefit, other than a Death Benefit in the form specified in Section 6.1, payable hereunder if such person or persons survive the Participant. This designation may be revoked at any time in similar manner and form prior to the commencement of benefits. In the event of the death of the designated Beneficiary prior to the death of the Participant, the Contingent Beneficiary shall be entitled to receive the Death Benefit unless the Beneficiary was named pursuant to Section 6.1, in which case the provisions of Section 6.1 shall govern. Notwithstanding the above, a married Participant may not designate a Beneficiary who is

not his Spouse without the written consent of his Spouse obtained in the manner required by the Plan Administrator.

1.10 Board shall mean the Board of Directors of the Company or the Management Committee of the Board of Directors to the extent that such committee has authority to act on behalf of the Board of Directors of the Company.

1.11 Break in Service shall mean a Plan Year in which the Employee is credited with fewer than five hundred and one (501) Hours of Service following his Severance from Service Date.

Notwithstanding the preceding paragraph and solely to determine whether a Break in Service has occurred, a Participant who is absent from work for maternity or paternity reasons shall receive credit for the Hours of Service that would otherwise have been credited to the Participant but for such absence, or in any case in which such Hours cannot be determined, ten (10) Hours of Service for each day of such absence. In no event, however, shall the Hours of Service credited pursuant to the immediately preceding sentence exceed five hundred and one (501). For purposes of this paragraph, an absence from work for maternity or paternity reasons means an absence (i) by reason of the pregnancy of the Participant, (ii) by reason of the birth of a child of the Participant, (iii) by reason of the placement of a child with the Participant in connection with the adoption of such child by the Participant, or (iv) for purposes of caring for such child for a period beginning immediately following such birth or placement. The Hours of Service credited under this paragraph shall be credited (i) in the Plan Year or other applicable computation period in which the absence begins if the crediting is necessary to prevent a Break in Service in that Plan Year or other computation period, or (ii) in all other cases, in the following Plan Year or other applicable computation period. Hours of Service shall also be credited to the extent necessary to comply with the Company's nondiscriminatory policies and procedures (such as an approved leave of absence or applicable layoff period), or the Family and Medical Leave Act, the Uniformed Services Employment and Reemployment Rights Act and other applicable law.

1.12 Cash Balance Account shall mean the bookkeeping entry reflecting a Participant's Accrued Benefit, as described in Section 3.6.

1.13 Code shall mean the Internal Revenue Code of 1986, as amended.

.4 Company shall mean Duke Power Company, a North Carolina corporation, and any successor, assign or other entity required to be included as part of the Company as a single employer under applicable provisions of the Code or ERISA.

1.15 Compensation shall mean, for all Participants, all amounts received for services actually rendered in the course of employment with the Employer maintaining the Plan to the extent that such amounts are includible in the Participant's gross income as wages required to be reported under Code Sections 6041, 6051 and 6052 (Box 1 of Form W-2), without regard to limits on wages under Code Section 3401, such as the exemption for agricultural labor. Compensation shall also include any amount which is contributed by the Employer pursuant to a salary reduction agreement and which is not includible in the gross income of the Participant under Code Sections 125 or 401(k). However,

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Compensation shall not include expense reimbursements and allowances, cash or noncash fringe benefits, moving expenses, the receipt of compensation previously deferred, excellence awards, welfare benefits, severance pay, pay for unused vacation, incentive pay paid after termination of employment, or long-term incentive payments (incentives attributable to multi-year performance periods for which no incentive is earned or paid until the end of the multi-year period). Incentive pay, including that attributable to participation in equity awards, that is paid to employees of Crescent Resources, Inc. will not constitute Compensation unless it is paid from the Crescent Resources Employee Goal Program.

Compensation of a Participant in excess of the amount authorized pursuant to Code Section 401(a)(17) ($160,000 for 1997) for any Plan Year or any portion of a Plan Year shall not be recognized; provided that the greatest amount authorized for Plan Years before 1994 shall be used retroactively to the extent permitted by the Code.

1.16 Contribution Credits shall mean the bookkeeping entry used to account for benefit contributions made on behalf of an Active Participant, as determined in accordance with Section 3.8.

1.17 Creditable Service shall mean the number of full years and fractions of years for which a Participant is given credit in calculating his Retirement Benefit, Termination Benefit or Death Benefit payable from the Plan, determined as follows:

(a) A Participant who was an employee on or before December 31, 1992, shall be credited with years of Creditable Service for the years and fractions of years during his employment prior to January 1, 1992 while he was eligible to participate, in accordance with the terms of the Prior Plan.

(b) For Plan Years beginning after December 31, 1992, a Participant shall be credited with one twelfth (1/12) year of Creditable Service for each full month in each period beginning on the date he satisfies the requirements for membership in the Plan or his Re-employment Commencement Date and ending on his Employment Termination Date and any partial calendar months ending on his Employment Termination Date during which he was a Participant.

(c) In determining a Participant's 1996 Plan Benefit, no more than 30 years of Creditable Service is taken into account, in accordance with the terms of the Prior Plan.

(d) If a Participant whose vested Accrued Benefit is zero (0) incurs five (5) or more consecutive Breaks in Service, the number of which equaled or exceeded the number of his years of Creditable Service prior to such consecutive Breaks in

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Service, his years of Creditable Service completed before such consecutive Breaks in Service shall be disregarded in determining his total years of Creditable Service.

Notwithstanding any other provision to the contrary, Creditable Service shall also include service credited to the extent necessary to comply with the Family and Medical Leave Act, the Uniformed Services Employment and Reemployment Rights Act and other applicable law.

1.18 Death Benefit shall mean any benefit paid to a Beneficiary or Contingent Beneficiary or other person at the death of a Participant or a Retired Participant, as provided under the terms of the Plan.

1.19 Defined Benefit Plan shall mean a plan that is established and qualified under Code Section 401 or 404 except to the extent it is, or is treated as, a Defined Contribution Plan.

1.20 Defined Contribution Plan shall mean a plan that is established and qualified under Code Section 401 or 403, which provides for an individual account for each participant therein and for benefits based solely on the

amount contributed to each participant's account and any income and expenses or gains or losses (both realized and unrealized) which may be allocated to such account.

:1 Disability Benefit shall mean the Retirement Benefit due a Disabled Participant.

1.22 Disability Date shall mean the date on which a Participant ceases to perform services for the Employer because of his Total and Permanent Disability.

1.23 Disability Distribution Date shall mean the first day of the month following a Participant's Disability Date that is coincident with or subsequent to the Participant's Early Retirement Date on which the Participant ceases to perform services for the Employer and he no longer receives Creditable Service because of his Total and Permanent Disability.

1.24 Disabled Participant shall mean any Active Participant who is Totally and Permanently Disabled.

1.25 Early Retirement Date shall mean, in the case of a Participant who has reached Attained Age fifty-five (55) and been credited with five (5) or more years of Vesting Service, the first day of the month coinciding with or otherwise immediately following the later of (a) the date the Participant shall leave the employ of the Company, or (b) the date the Participant directs in writing shall be his Early Retirement Date.

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1.26 Effective Date shall mean the January 1, 1997, effective date of this amended and restated Plan, except as otherwise specifically provided herein.

1.27 Employee shall mean any individual who is a common law employee of the Employer, including Leased Employees, unless such Leased Employees are members of a money purchase pension plan sponsored by the leasing organization that provides immediate participation, full and immediate vesting and a non-integrated contribution equal to at least seven and one-half percent (7-1/2%) of the employee's compensation.

1.28 Employer shall mean Duke Power Company, and any other Affiliate that adopts this Plan in writing, or any successor to Duke Power Company or Affiliate.

9 Employment Commencement Date shall mean the date an Employee first performs an Hour of Service for the Employer

coincident with or following his date of hire or rehire.

1.30 Employment Termination Date shall mean the date on which an Employee dies, or the date on which he quits, retires, or is discharged, otherwise terminates employment with the Employer.

1.31 ERISA shall mean the Employee Retirement Income Security Act of 1974, as such Act may be amended from time to time.

1.32 Grandfathered Early Retirement Date shall mean, in the case of a Participant who was an Employee before the Effective Date, was a participant in the Prior Plan, has reached Attained Age fifty-one (51), and has been credited with thirty (30) or more years of Creditable Service under the terms of the Prior Plan, the first day of the month coinciding with or otherwise immediately following the date the Participant leaves employment with the Company and he directs in writing that his Annuity Starting Date begin before Attained Age fifty-five (55).

1.33 Highly Compensated Employee shall mean a person who, (1) during the look-back year or the determination year, was at any time a five percent (5%) owner of the Employer; or (2) during the look-back year received compensation from the Employer in excess of eighty thousand dollars ($80,000) (or such higher amount as may be provided under Code Section 414(q));

(a) For purposes of determining Highly Compensated Employees, compensation shall mean compensation paid by the Employer for purposes of Code Section 415(c)(3) and shall include amounts deferred pursuant to Code Sections 125 (flexible benefit plans); 402(g)(3) (salary redirection); and 402(h)(1)(B) (simplified employee plans).

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(b) A former employee shall be treated as a Highly Compensated Employee if (1) such employee was a Highly Compensated Employee when he separated from service, or (2) he was a Highly Compensated Employee at any time after reaching Attained Age fifty-five (55).

(c) Except as otherwise provided in this Section, the look-back year shall be the twelve (12) month period immediately preceding the determination year and the determination year shall be the current Plan Year.

(d) Highly Compensated Employees shall be determined on a Company-wide basis (including all Affiliates)

rather than by Employer or by plan.

(e) The determination of Highly Compensated Employees shall be governed by Code Section 414(q) and the regulations issued thereunder.

1.34 Hour of Service shall mean each hour for which an Employee is paid, or entitled to payment, by the Company during the applicable computation period (i) for the performance of duties; (ii) on account of a period of time during which no duties are performed, regardless of whether the employment relationship has terminated; and (iii) as a result of a back pay award that has been agreed to or made by the Employer to the extent that such hour has not previously been credited under item (i) or item (ii) preceding (irrespective of mitigation of damages).

(a) The number of Hours of Service to be credited on account of a period of time during which no duties are performed (including hours resulting from a back pay award) shall be determined as follows. If the payment which is made or due is calculated on the basis of units of time, the number of Hours of Service to be credited shall be the number of regularly scheduled working hours included in the units of time on the basis of which the payment is calculated. If an employee does not have a regular work schedule, the number of Hours of Service to be credited shall be calculated on the basis of an eight (8) hour work day. If the payment which is made or due is not calculated on the basis of units of time, the number of Hours of Service to be credited shall be calculated by dividing the amount of the payment by the employee's most recent hourly rate of compensation before the period during which no duties were performed, determined as follows:

(1) If the employee's compensation is determined on the basis of an hourly rate, such hourly rate shall be the employee's most recent hourly rate of compensation.

(2) If the employee's compensation is determined on the basis of a fixed rate for a specified period of time other than hours, his hourly rate of

compensation shall be his most recent rate of compensation for the specified period of time, divided by the number of hours regularly scheduled for the performance of duties during such period of time; if an employee does not have a regular work

schedule, his hourly rate of compensation shall be calculated on the basis of an eight (8) hour work day.

(3) If the employee's compensation is not determined on the basis of a fixed rate for a specified period of time, his hourly rate of compensation shall be the lowest hourly rate paid to employees in his job classification, or, if no employees in his job classification have an hourly rate of compensation, the minimum non-training wage in effect under Section 6(a)(1) of the Fair Labor Standards Act of 1938, as amended.

(b) In no event shall the application of the terms of Section 1.34(a) result in crediting an employee with a number of Hours of Service during the period which is greater than the number of hours regularly scheduled for the performance of duties. If an employee has no regular work schedule, the number of Hours of Service to be credited to him shall not exceed the number which would be credited calculated on the basis of an eight (8) hour work day.

(c) No employee shall be credited with more than five hundred and one (501) Hours of Service as a result of the application of Section 1.34(a) for any single continuous period during which he performs no duties, regardless of whether such period extends beyond one (1) Plan Year or other applicable computation period.

(d) The Plan Year or other applicable computation period to which Hours of Service shall be credited shall be determined as follows:

(1) Except as hereinafter provided, Hours of Service credited in accordance with item (i) of the first paragraph of Section 1.34(a) shall be credited in the Plan Year or other applicable computation period in which the duties were performed.

(2) Except as hereinafter provided, Hours of Service credited in accordance with item (ii) of the first paragraph of Section 1.34(a) shall be credited: if calculated on the basis of units of time, to the Plan Year or Plan Years or other applicable computation period in which the period during which no duties are

performed occurs, beginning with the first unit of time to which the payment relates; otherwise, to the Plan Year or other applicable computation period in which the period during which no duties are performed occurs, provided that if the period during which no duties are performed extends beyond one (1) Plan Year or other applicable computation period, such Hours of Service shall be allocated between not more than the first two (2) Plan Years or other applicable computation periods on any reasonable basis consistently applied.

(3) Except as hereinafter provided, Hours of Service credited in accordance with item (iii) of the first paragraph of Section 1.34(a) shall be credited to the Plan Year or other applicable computation period to which the award or agreement for back pay pertains rather than to the Plan Year or other applicable computation period in which the award, agreement, or payment is made.

(4) Hours of Service to be credited to an employee in connection with a period of no more than thirty-one (31) days which extends beyond one (1) Plan Year or other applicable computation period may be credited to the first or the second computation period, provided such crediting is done on a reasonable and nondiscriminatory basis.

(e) An Employee or Participant for whom hourly records are not maintained who is compensated on a bi-weekly basis shall be credited with ninety-five (95) Hours of Service for each bi-weekly payroll period in which he would otherwise be credited with one (1) Hour of Service in accordance with the first paragraph of Section 1.34(a). An Employee or Participant for whom hourly records are not maintained who is compensated on a monthly basis shall be credited with one hundred and ninety (190) Hours of Service for each monthly payroll period in which he would otherwise be credited with one (1) Hour of Service in accordance with the first paragraph of Section 1.34(a).

(f) Nothing in this Section shall be construed to alter, amend, modify, invalidate, impair or supersede any law of the United States or any rule or regulation issued under any such law. The nature and extent of any credit for Hours of Service under this Section shall be determined under such law.

1.35 Interest Credits shall mean the bookkeeping entry used to account for investment earnings contributions made on behalf of a Participant, as determined in accordance with Section 3.9.

1.36 Investment Manager shall mean any fiduciary appointed

under Section 12.4 who meets the definition of the term "investment manager" under Section 3(38) of ERISA and who acknowledges in writing that he is a fiduciary with respect to this Plan.

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1.37 Key Employee shall mean any employee, former employee or beneficiary thereof in an Internal Revenue Service qualified plan adopted by the Employer who at any time during the applicable Plan Year or any of the four (4) preceding Plan Years is defined in Sections (a) through (d) of this Section.

(a) An officer of the Company, including Affiliates, having annual compensation during the Plan Year greater than fifty percent (50%) of the amount in effect under Code Section 415(b)(1)(A) for the calendar year in which such Plan Year ends;

(b) One (1) of the ten (10) employees having annual compensation from the Company for a Plan Year of more than the limitation in effect under Code Section 415(c)(1)(A) for the calendar year in which such Plan Year ends, and owning (or considered as owning within the meaning of Code Section 318) both more than a one-half percent (1/2%) interest, and the largest interest, in the Employer;

(c) A five percent (5%) owner of the Employer; or

(d) A one percent (1%) owner of the Employer having annual compensation from the Company or Affiliate for a Plan Year of more than one hundred and fifty thousand dollars ($150,000).

(e) For purposes of this Section, compensation has the same meaning as under Code Section 415(c)(3).

(f) This definition shall be interpreted consistent with Code Section 416 and rules and regulations issued thereunder. Further, such law and regulations shall be controlling in all determinations under this definition, inclusive of any provisions and requirements stated thereunder but hereinabove absent.

1.38 Late Retirement Date shall mean the first day of any month subsequent to the Participant's Normal Retirement Date coincident with or otherwise immediately following the date the Participant terminates employment for any reason other than death.

1.39 Leased Employee shall mean any person (other than an employee of the Employer) who provides services to the Employer as a "leased employee," as such term is defined in Section 414(n) and (o) of the Code.

1.40 Limitation Year shall mean the Plan Year.

1.41 1996 Plan Benefit shall mean the benefit which a Participant had accrued as of December 31, 1996 under the terms of the Prior Plan in effect on December 31, 1996, based on Compensation and Creditable Service earned through such date.

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1.42 1996 Terminated Participant shall mean

(a) an individual who was not an Employee as of the Effective Date, who was an active Participant in the Prior Plan or any predecessor plan to such Prior Plan, who has a Reemployment Commencement Date after the Effective Date, who has not commenced receiving a distribution of the Participant's benefit as of such Reemployment Commencement Date or whose benefit payments have ceased in accordance with Section 4.6, and whose prior Vesting Service as of such Reemployment Commencement Date is not lost because of an application of the rule provided in the definition of Vesting Service, or

(b) an individual who was an Employee who had commenced receiving a distribution as of the Effective Date and whose benefit payments subsequently ceased in accordance with Section 4.6 following the Effective Date.

1.43 Normal Retirement Date shall mean the first day of the month coincident with or otherwise immediately following the date a Participant reaches Attained Age sixty-five (65).

1.44 Partial Disability shall mean a physical or mental disability that prevents a participant from engaging in his normal occupation with the Employer and which causes the Participant to be eligible for partial disability payments as a result of a long-term disability, pursuant to the Duke Power Company Disability Plan or other long-term disability plan maintained by the Company for the purpose of providing long-term disability benefits.

1.45 Participant shall mean any Employee who has met the eligibility requirements for participation in the Plan as set forth in Article 2, or any former Employee with an undistributed, nonforfeitable Accrued Benefit under this

Plan.

46 Permissive Aggregation Group shall mean the Required Aggregation Group and any other plan or plans of the Company that are not required to be included in the Required Aggregation Group, but which, if treated as being part of such Group, would not cause such Group to fail to meet the requirements of Code Sections 401(a)(4) and 410.

1.47 Plan shall mean the Duke Power Company Retirement Cash Balance Plan, as amended from time to time.

1.48 Plan Administrator shall mean the Company, unless the Employer designates another person to hold the position as Plan Administrator. A Retirement Plan Committee may be designated to carry out the functions of the Plan Administrator.

1.49 Plan Year shall mean the calendar year.

1.50 Prior Plan shall mean the provisions of this Plan as in effect prior to January 1, 1997, and amended as of the Effective Date as part of this restatement. Such provisions are included in the Plan by this reference.

1.51 Qualified Joint and Survivor Annuity shall mean the Actuarial Equivalent of a Participant's normal form of Retirement Benefit payable as a monthly income for the lifetime of the Participant and continuing thereafter, in an amount fifty percent (50%) as large, to the Participant's Spouse for the lifetime of the Spouse.

1.52 Required Aggregation Group shall mean (1) each plan of the Company in which a Key Employee is a participant, (2) each other plan of the Company which enables any plan in (1) to meet the requirements of Code Section 401(a)(4) or 410; and (3) each terminated plan maintained by the Company within the five (5) year period ending on the determination date for the Plan Year in question which would, but for the fact that it terminated, meet the criteria of (1) or (2) preceding.

1.53 Reemployment Commencement Date shall mean the date on which an Employee first performs an Hour of Service for the Employer after terminating his employment and incurring a Break in Service.

4 Retirement Benefit shall mean the pension benefit due a retired Participant which shall commence as of his