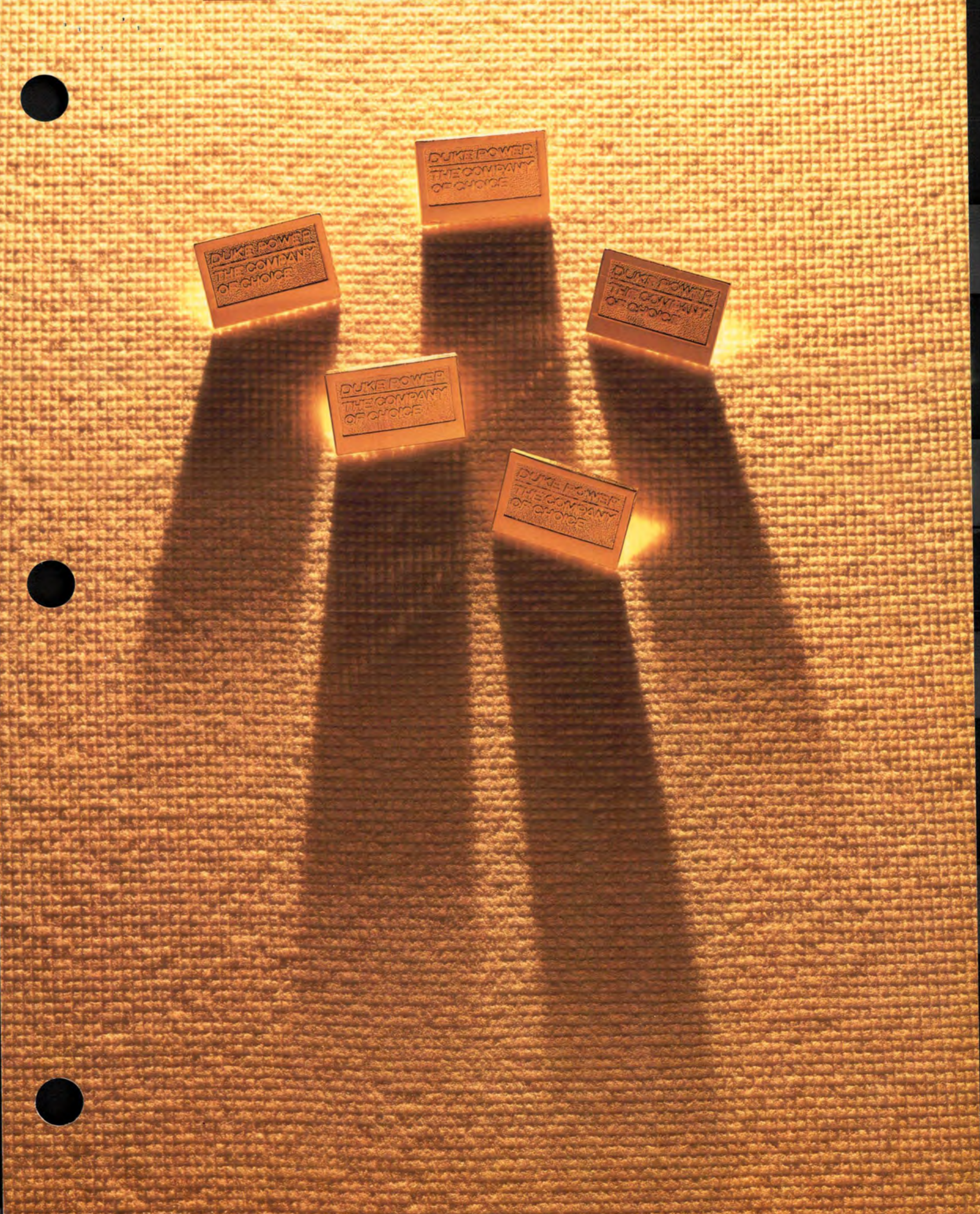
Duke Power Company



1992 Annual Report

FINANCIAL HIGHLIGHTS

	1992	1991	Percent increase (decrease)
Kilowatt-hour sales (millions)	**71,042**	69,887	[illegible]
Electric revenues	**$3,961,484,000**	$3,816,960,000	3.8
Earnings for common stock	**$ 451,676,000**	$ 528,940,000	(14.6)
Common stock data			
Average shares outstanding	**204,819,000**	203,431,000	0.7
Earnings per share	**$2.21**	$2.60	(15.0)
Dividends per share	**$1.76**	$1.68	4.8
Book value per share (year-end)	**$20.26**	$19.86	2.0
Return on average common equity	**11.1%**	13.5%	(17.8)
Plant construction costs (including AFUDC)	**$ 463,971,000**	$ 606,614,000	(23.5)
Nuclear fuel construction costs (including AFUDC)	**$ 127,855,000**	$ 193,019,000	(33.8)
Internal cash generation	**50%**	77%	(35.1)
Earnings coverage of fixed charges, SEC method	**3.48X**	3.85X	(9.6)
Total electric plant, net	**$8,881,908,000**	$8,698,641,000	2.1
Peak load (KW) (a)			
Summer	**14,763,000**	14,677,000	0.6
Winter	**13,001,000**	12,778,000	1.7
Number of employees (b)	**17,968**	18,187	(1.2)

(a) Duke Power Company experienced an all-time peak of 14,763 MW on July 14, 1992.
(b) Full-time employees (excluding subsidiaries and affiliates).

ABOUT THE COVER

Duke Power's foundation for planning is its vision: to become the Company of Choice. Achieving that goal means that the Company's shareholders will make Duke Power their investment of choice, that its customers will choose Duke Power for electric energy and related products, that employees will choose Duke as the company they most want to work for and that the Company will be the model of integrity and excellence. The Company's Strategic Plan guides its actions; the accomplishments made in 1992 under that plan are discussed in this year's Annual Report.

ABOUT DUKE POWER

Headquartered in Charlotte, N.C., Duke Power supplies electricity to more than 1.7 million residential, commercial and industrial customers in a 20,000 square-mile service area in North Carolina and South Carolina. Since its founding nearly 90 years ago, the Company has grown to become the nation's seventh-largest investor-owned electric utility.

Duke Power, which operates three nuclear generating stations, eight coal-fired stations and 27 hydroelectric stations, produced 79 billion kilowatt-hours of electricity in 1992. Electric revenues totaled $4 billion. About 70 percent of sales were in North Carolina and about 30 percent were in South Carolina.

Retail customers are currently served from the Company's Customer Service Center and through a network of customer service offices located throughout Duke Power's service area. In addition, the Company serves wholesale, bulk power and contractual customers.

Nantahala Power and Light Company, a Duke Power subsidiary, provides electricity to about 51,000 customers in a five-county area in western North Carolina. Nantahala is headquartered in Franklin, N.C.

CONTENTS

Nantahala Power and Light Company
Duke Power Company

To Our Shareholders

Your Company earned $508 million in 1992, down from $584 million in 1991. Earnings per share of common stock fell to $2.21 per share, a 15 percent decline from 1991.

The principal factor depressing earnings was a refund to customers associated with the final resolution of the Company's 1986 rate case. The North Carolina Supreme Court ruled that the facts of the case did not support the rate of return on common equity previously approved by the North Carolina Utilities Commission. The approximately $95 million refund to North Carolina retail customers reduced earnings by 32 cents per share of common stock.

Increased operating and maintenance costs also lowered earnings by 20 cents per share. These costs included steam generator repair work at the McGuire and Catawba nuclear stations, and increased operation and maintenance at our fossil plants. The Company's plan to replace the steam generators at McGuire and Catawba is outlined elsewhere in this report.

Kilowatt-hour (kwh) sales for the year totaled 71.0 billion kwh, up 1.7 percent from 69.9 billion kwh in 1991. Cooler summer weather reduced sales to residential customers, while sales to industrial and general service customers increased as a result of the continuing economic recovery.

Textile sales continued a rebound begun in 1991. Your Company recorded its highest sales year to textile companies in 1992, selling 11.7 billion kwh to textile customers. This is an encouraging sign that the textile industry is regaining strength.

We are also encouraged that our sales to other industrial customers were up 2.7 percent over 1991.

Congress Sets New National Energy Policy

The U.S. Congress passed the Energy Policy Act of 1992. We strongly supported this landmark legislation, which creates a comprehensive national energy policy. This wide-ranging Act includes:

>Amendment of the Public Utility Holding Company Act (PUHCA) to authorize development of wholesale generating plants without becoming subject to registration under PUHCA as an electric utility holding company.

>Providing for access by electricity generators to a utility's transmission lines provided reliability of service to the utility's local customer base is protected.

>Streamlining the licensing process for new nuclear generating facilities.

The Act also includes provisions to encourage energy efficiency and conservation, fund an electric vehicle demonstration project, and expedite the development of a high-level radioactive waste repository. We anticipate that the Act will open the door to additional business opportunities for us, but it will also challenge us to be a cost-effective producer in order to be the supplier of choice for our customers.

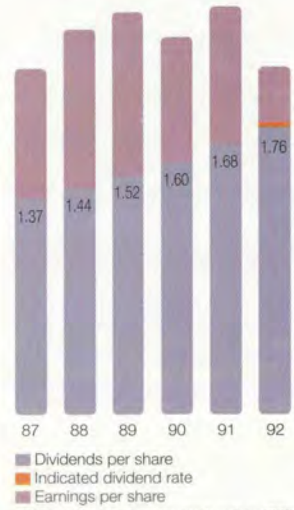
Lincoln Combustion Turbine Station Construction Slated

Construction on the 16-unit Lincoln Combustion Turbine Station is scheduled to begin in the spring of 1993. Lincoln is a 1,184-megawatt peaking power generating station. Plans call for completion of the first four units by mid-1995 and the remaining units by the end of 1996. The plan for the Lincoln project is integrated with strong promotion of demand-side energy savings which will enable us to meet the growing power needs of our customers cost effectively.

Duke Goes International

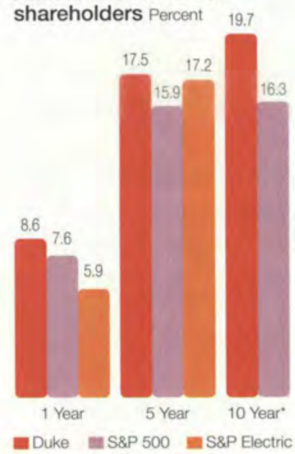
In September 1992, Duke Energy Corp., Duke Power's power development affiliate, led a consortium that purchased the majority interest in the Guemes Power Station in Argentina. Duke Engineering & Services, Inc. (DE&S) is leading the team that operates the plant.

Earnings per share* Dollars



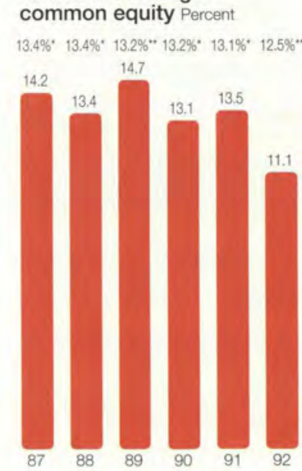
*Reflects the two-for-one stock split in 1990.

Annual total return to shareholders Percent



*10 Year S&P Electric data not available.

Return on average common equity Percent



*Average authorized return (NC jurisdiction)
**In 1989 the NC authorized return was reduced to 13.2% retroactive to October 31, 1986.
***In 1992 the NC authorized return was reduced a second time to 12.8% from November 11, 1991 to October 31, 1986.

DE&S opened an office in Melbourne, Australia, in January 1993. DE&S is providing consulting services to the State Electricity Commission of Victoria and is exploring other business opportunities in Australia. Duke Energy also is examining additional opportunities in electric generation [illegible]gentina as well as Australia and the Pacific Rim.

In another milestone, the Mecklenburg Cogeneration Facility began commercial operation in November 1992, ahead of schedule and under budget. The 130-megawatt coal-fired plant in Virginia provides steam for a textile plant and sells electricity to Virginia Power Company. Duke Energy developed the project with an affiliate of Transco Energy of Houston, Texas. Duke/Fluor Daniel, a joint venture between DE&S and Fluor Daniel, Inc., designed, built and operates the plant for affiliates of Duke Energy and Transco Energy.

These efforts support the strategic objective of improving return on equity through diversification in synergistic businesses.

Competing In Today's World

Whereas electric utilities were once considered protected monopolies, today Duke Power is vigorously competing on many fronts. We are competing for our customers' business with gas companies, with municipal and cooperative electric systems and with independent and customer-owned generation. We compete with utilities nearby and elsewhere for economic development of our region. Many of our industrial customers face fierce competition in the world marketplace, putting us in competition with electric suppliers all over the world. In 1992, our average retail price for electricity was 5.71 cents per kwh, lower than the 1987 price of 5.92 cents.

We compete in the capital markets for investment dollars. To succeed, our returns to shareholders must grow. We have a goal of increasing our dividends faster than the rate of inflation, and [illegible] grew to $1.76 in 1992 from $1.37 per share in 1987, achieving that goal.

To increase profits while keeping prices competitive, our employees compete with others in the quest for excellence.

The Quest for Excellence Continues

At Duke Power, 1992 was the Year of Education as we progressed on our journey to excellence. Employees throughout the Company have participated in quality improvement training workshops. These workshops are designed to give all employees a common quality language and enabling tools to improve quality, deliver total customer satisfaction and lower costs.

Helping to lead us on our journey are Bill Grigg, Bill Coley, Steve Griffith and Rick Priory. Elsewhere in this report, these executives offer their insights about the issues facing us and the excellence process. I firmly believe the excellence process is one of the most vital efforts your Company has ever undertaken. With the passage of the Energy Policy Act, competition will only accelerate. How we anticipate, adapt and quickly deliver products and services depends on how well we understand our customers.

It is a thrill to see the ever-improving performance of our teammates through their growing commitment to customers, to each other and to you, our owners. Those of us who work at Duke Power appreciate your continued support and hope you feel the excitement we experience as your Company continues its quest for excellence. Our efforts are making a difference; we think you will like what you see in the years ahead.

William S. Lee

William S. Lee
Chairman of the Board, President and Chief Executive Officer
February 15, 1993

YEAR IN REVIEW

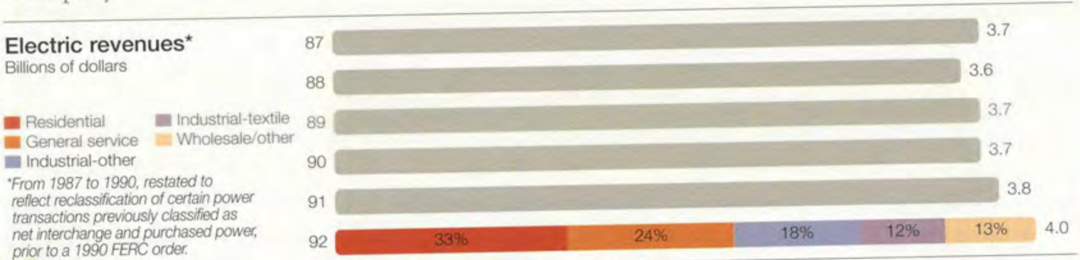
Duke Power's seven-point strategic plan continued to guide the Company through 1992. The plan outlines areas of strategic focus considered critical to Duke's future success. These areas [illegible]ustomer satisfaction, financial management, nuclear excellence, expanding business opportunities, environmental leadership, team excellence, and the excellence management philosophy. By achieving objectives in each of these areas, Duke Power will build upon its past success to create an even stronger company.

CUSTOMER SATISFACTION

Our strategic focus: To understand and meet our customers' expectations.

Duke Power makes extensive use of customer feedback to determine how to respond to customers' needs and wants. As a result of that feedback, the Company began several new services during 1992.

Duke's Customer Service Center now provides 24-hour-a-day, seven-day-a-week service by telephone for all customers. Customers may call at their convenience to conduct business with the Company.

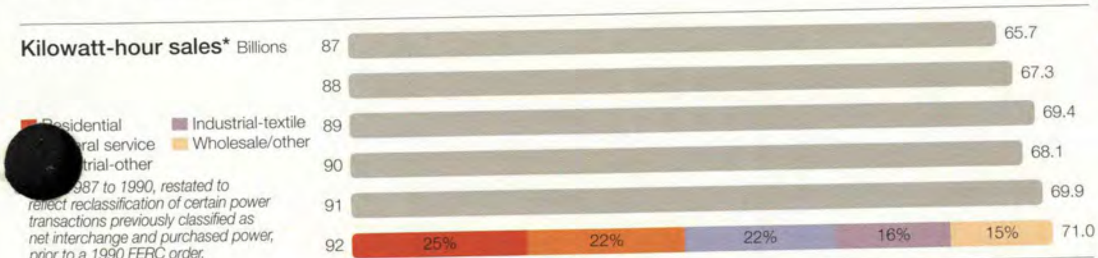


Customers wanting information about their account status also have the option of telephoning AutoBill, Duke's automated account information system. Another automated system receives and processes power outage reports. Customers can call 1-800-PowerOn to report outages. The system can handle up to 12,000 calls an hour and uses the caller's phone number to locate the outage.

Duke Power also understands that customers expect the Company to meet their needs for energy now and in the future. Duke is committed to meeting those needs through both demand-side and supply-side energy options. These options are outlined in the Company's Integrated Resource Plan, which projects how the Company intends to use its resources to meet customers' needs for energy over the next 15 years.

The demand-side programs are designed to help customers conserve energy and shift their usage to non-peak periods. These programs help customers save money on their power bills and also help the Company minimize capital expenditures for new generating capacity.

Unquestionably, however, economic development and customer growth will foster greater demand. Sales are forecast to increase by more than 2 percent annually over the next 10 years. Some of that demand will be met by the 1,184-megawatt Lincoln Combustion Turbine Station. Current plans call for completing four 74-megawatt combustion turbines at the Lincoln Station by mid-1995 and 12 more by the end of 1996.

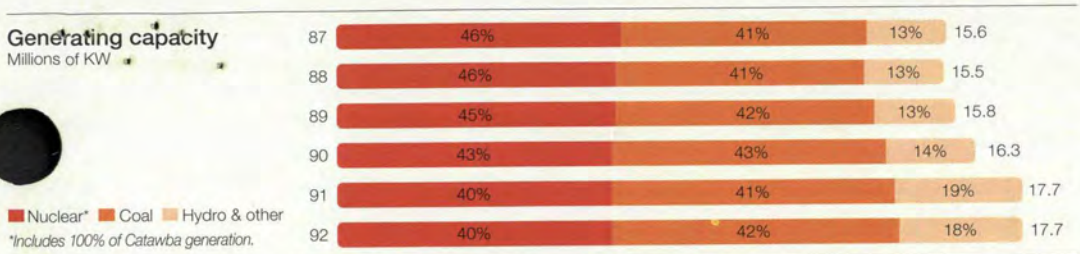


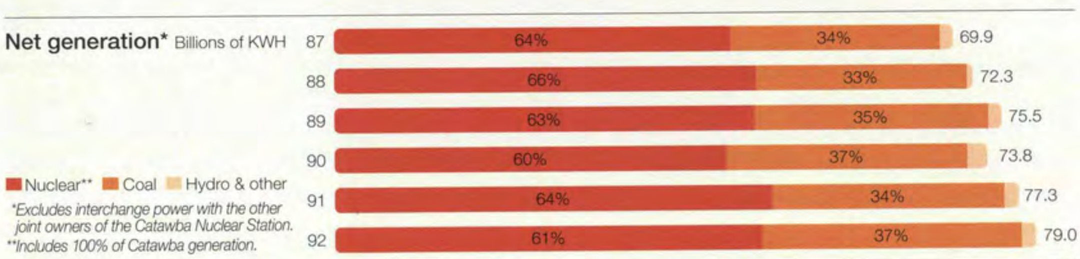
Duke Power's Barbara Orr, Spartanburg Area Manager, and Milliken Company President Tom Malone tour Milliken's Research Center in Spartanburg, S.C. Milliken, long known for its commitment to quality, and Duke Power have joined forces to create a quality partnership designed to enhance the profitability of both companies and build a better working relationship between supplier and customer.

1992 Sales-KWH

Residential	-0.7%
General service	+1.5%
Textile	+3.3%
Non-textile industrial	+2.7%
Total industrial	+2.9%
All other	+2.8%
Total	+1.7%

In an earlier day, Duke Power met customers' needs with products like this electric heater. Models like this one were used by some Duke Power customers to provide heat in their homes quickly and easily. It's just one of the electric products developed over the years that have made living easier and more comfortable.





Duke Power's Riverbend Steam Station is one of several coal-fired plants that have been updated under the Company's Plant Modernization Program. The program is designed to modernize older coal-fired stations to permit them to operate more efficiently and provide additional energy at a fraction of the cost of building new base-load plants.

Financial Management

Our strategic focus: To manage the business to increase value and lower costs.

Duke Power's earnings per share of common stock dropped in 1992 to $2.21, down 15 percent from 1991. Total sales rose 1.7 percent to 71.0 billion kwh.

The biggest single factor in the decline was a charge against earnings totaling 32 cents per share from the $95 million refund to North Carolina retail customers. The refund became necessary after the North Carolina Utilities Commission retroactively lowered the Company's authorized rate of return on common equity for the five-year period ended in November 1991 to 12.8 percent from percent. The rate of return is a key factor used to set the price of electricity.

Increased operating and maintenance expenses reduced earnings by 20 cents per share. These increased costs were related primarily to steam generator repair work at two of the Company's nuclear stations, and increased operating and maintenance expenses at our fossil plants.

Kilowatt-hour sales to residential customers were down 0.7 percent compared with 1991. Sales to textile customers increased 3.3 percent, while sales to other industrial customers rose 2.7 percent. Sales to general service customers increased 1.5 percent.

Taking advantage of continued low interest rates, the Company refinanced numerous outstanding bond and preferred stock issues over the course of the year. Securities with a total face value of $1.1 billion were refinanced, which reduced the embedded cost of outstanding debt to 8.39 percent at the end of 1992 from 8.72 percent at the end of 1991 and that of preferred stock to 7.05 percent from 7.48 percent.

In September, the Company increased its quarterly per-share dividend to 45 cents from 43 cents. During the five years ending 1992, the annual dividend per share increased at an average rate of 5.1 percent. 1992 was the 17th consecutive year that the Board of Directors raised the dividend.

Below, an electric meter that accepted quarters was one way consumers bought electricity in the early part of this century.


ume fashions fo
$19.99

NUCLEAR EXCELLENCE

Our strategic focus: To safeguard and serve the public with our nuclear investment.

Duke Power has consistently produced more than 60 percent of total generation each year from the three nuclear stations it operates. In 1992, 61 percent of electricity generated was provided by the nuclear plants. Keeping the seven units at the Oconee, McGuire and Catawba nuclear stations in safe and efficient operating condition is critical to the Company's ability to meet customer demand.

As part of this effort, Duke will replace the steam generators in both units at McGuire and in Unit 1 at Catawba due to microscopic cracking in some of the steam generator tubes in those units. Steam generators are large heat exchangers that transfer heat from reactor water to feed water to create steam. The steam then drives the turbines which power the electric generators. Replacing the steam generators as scheduled will enable these plants to continue operating with cost-effective reliability for many years.

Duke signed a contract with Babcock & Wilcox International in 1992 to fabricate the replacement steam generators. The new generators will be installed by extending planned refueling outages to lessen the impact on Duke's nuclear generation. The first outage is scheduled to begin in 1995, and the third outage is scheduled to end in 1997. The project is expected to cost approximately $200 million per unit, excluding the cost of replacement power and without consideration of any reimbursement by the other Catawba joint owners.

Although the number of nuclear outage days increased over last year, Duke's nuclear plants continued to run more efficiently than the national average. Collectively, Duke's nuclear plants ran at 78 percent of capacity in 1992, compared with a national average of 70 percent in 1991, the latest year for which statistics are available. Catawba Unit 1 set a unit record of 281 days of continuous operation, and Catawba Unit 2 posted a unit record of 262 days of continuous operation during the year. Based on Nuclear Regulatory Commission statistics for 1991, the latest year for which figures are available, Duke's three nuclear stations were the first, second and third most efficient multi-unit stations in the country in converting uranium energy to electricity.

When Massachusetts-based retailer T.J. Maxx needed a new warehouse for a distribution center in Charlotte, they turned to Duke subsidiary Crescent Resources, Inc. Crescent is developing a 600,000 square-foot build-to-suit warehouse near Charlotte for T.J. Maxx, putting nearly 14 acres under one roof.

EXPANDING BUSINESS OPPORTUNITIES

Our strategic focus: To profitably use our strengths to serve a variety of customers and enhance developmental opportunities for employees.

Duke Power's ability to design, build and operate power plants has always been a competitive advantage for the Company. Duke Power's subsidiaries and affiliates are also showing that they are able to successfully compete in diverse markets. During 1992, the subsidiaries, affiliates and non-utility operations contributed 15 cents per share of common stock to corporate earnings, up from 13 cents per share in 1991.

During 1992, Duke Energy Corp. celebrated the start of commercial operation of the Mecklenburg Cogeneration Facility, located in Virginia. Duke Energy also led an international consortium that acquired majority ownership of the Guemes Power Station, a 245-megawatt natural gas-fueled plant in Argentina. Duke Energy now manages interests in three operating power plants totaling over 425 megawatts and approximately $400 million in assets.

Duke Energy's primary focus will continue to be the development of coal-fueled projects in the United States. It will pursue natural gas-fired projects and other electric facilities in the United States and abroad as opportunities arise.

In February 1993, Duke Energy announced an agreement to enter into a strategic alliance with Makowski & Company, one of the premier developers of natural gas-fired electric projects. The combined experience of Duke Energy and Makowski would strengthen prospects for successful development of power generation projects, particularly those fueled with natural gas.

Below, this medal commemorates January 25, 1982, the date of the Company's first board meeting after Unit 1 at McGuire Nuclear Station began commercial operation. Unit 1 began commercial operation the previous month.


ELEMENTS OF
QUALITY IMPROVE
1) MANAGEMENT

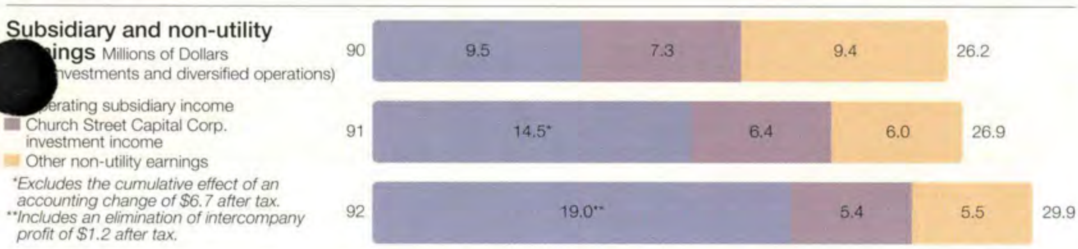
Serving the electric and related industries, Duke Engineering & Services, Inc., (DE&S), provides engineering, project management, construction, operations, maintenance and power delivery services, primarily for energy-related projects. DE&S also provides information technology services and training in human resources, safety and health, and media and community relations. One strategy of success has been to team with carefully selected companies to offer a variety of services. A team including DE&S was recently awarded a contract to provide steam generator replacement services to the St. Lucie nuclear plant in Florida.

Duke/Fluor Daniel, a joint venture between DE&S and Fluor Daniel, Inc., began construction of a 385-megawatt coal-fired plant for South Carolina Electric & Gas Co. in late 1992. The project is scheduled for commercial operation in 1996.

Crescent Resources, Inc., Duke's real estate development and forest management subsidiary, achieved favorable results despite the still-slow real estate industry. Crescent's strategy of concentrating on high-quality commercial and residential projects in the Carolinas continues to pay off. At year-end, 89 percent of Crescent's more than 1,132,000 square feet of leasable commercial, retail, office and warehouse space was filled. The company is developing a 600,000 square-foot build-to-suit warehouse for retailer T.J. Maxx. At The Peninsula, Crescent's golf course residential community on Lake Norman, a total of 230 lots had been sold at year-end out of 642 ultimate home sites at an average price of $142,000.

Crescent's forestry department, which manages approximately 270,000 acres of land, harvested 22.8 million board feet of timber and 72,800 cords of pulpwood for the construction, furniture and paper industries.

Duke Power's commitment to excellence is demonstrated in many ways throughout the Company. Here, employees learn the foundations of quality in a Managing For Excellence class. Over the last two years, Duke employees have participated in excellence training that gives all teammates an understanding of and a common language for excellence.



Environmental Leadership

Our strategic focus: To provide leadership to maintain a sustainable environment.

Duke Power and its employees believe that no company can claim a position of leadership without a strong commitment to protecting and sustaining our environment. Duke's commitment in this area resulted in the Company being recognized by the North Carolina Governor's Waste Management Advisory Board in 1992 for its innovative battery recycling program. The South Carolina Wildlife Federation named Duke its 1992 Conservationist of the Year in recognition for the Company's efforts at conserving the state's natural resources, while at the same time responding to the demand for electricity. Through its various recycling programs, Duke recycled 188 tons of hazardous waste and 21,424 tons of non-hazardous waste in 1992.

Duke Power's nuclear plants contribute to environmental quality by generating power without releasing harmful emissions into the atmosphere. The Company also uses low-sulfur coal at its fossil plants, which have consistently been ranked among the most efficient in the nation. As a result of our fossil efficiency and fuel choice, Duke already meets the Clean Air Act's sulfur dioxide Phase I requirements. The Company is developing its strategy for complying with the Phase II requirements by the year 2000.

System operators in the Company's early days used another means of communication with the operators of the Company's hydroelectric stations. These insulators were used on the "hotline" telephone system. Depending on system demand, system operators would use the hotline to phone a hydroelectric station and order the gates on the dams open or closed, increasing or decreasing the amount of power that went out on the power grid.

TEAM EXCELLENCE

Our strategic focus: To prepare the team to achieve excellent business results and reward success.

During 1992, Duke Power sent its employees back to school. Drawing from the Quality Improvement Flagship teams that were set up to test the Company's quality improvement process, Duke provided intensive quality improvement training to employees throughout the Company.

Employees are using the tools provided through quality training to create quality improvement teams. For example, during 1992 employees used quality processes to reduce the number of recordable injuries by 20 percent over the latest three-year average. Employees in the Controller's Department and other areas improved processing of vendor invoices so that less time was spent correcting errors before payment. And in Power Delivery, quality improvement teams worked to improve the quality of the power delivered to customers by five percent.

These improvements are tangible signs that, with the tools and the opportunity, Duke Power employees will find innovative ways to improve quality and deliver the products and services our customers want. As the Company moves along its path to excellence, the process of continuous improvement will result in many more successes like these.

EXCELLENCE MANAGEMENT PHILOSOPHY

Our strategic focus: To implement the Excellence Management Philosophy throughout our business.

Duke Power made great strides in 1992 toward its goal of becoming a world-class company. The creation of quality steering teams throughout the Company provides employees with an opportunity to enhance quality.

Another step taken in 1992 was the creation of the Corporate Performance Review Committee to offer policy recommendations for improving performance and to support the Company's emphasis on continuous improvement. The committee consists of four members of the Board of Directors from outside the Company.

Duke also conducted its second Baldrige assessment during 1992, using criteria developed for the Malcolm Baldrige National Quality Award program. The Company's goal is to score within the top 25 percent of companies applying for the award in 1996.

A spirit of teamwork is growing at all levels of Duke Power. It is a spirit born of the understanding that excellence cannot be achieved without the cooperation and support of every employee. It is a spirit nurtured by the belief that excellence will make Duke Power a stronger, more competitive company that offers its employees greater opportunity to contribute to the Company's success. But, most importantly, it is a spirit driven by the realization that, to succeed, Duke Power must strive to meet the expectations of our customers all of the time. That is our definition of quality, and it is a goal we are confident we will achieve.

From slide rules to computer-aided design equipment, the electric utility industry has come a long way since Duke Power began operating in 1904. These slide rules belonged to Duke Power Chairman Bill Lee and former Chief Engineer David Nabow; today, engineers use powerful desktop computers. The goal is still the same, however: to build the best generating plants that we can to ensure quality and reliable service to our customers.

PERSPECTIVES ON CHANGE

Duke Power is organized into four groups, each led by a senior executive. Vice Chairman William H. Grigg oversees the Corporate Group. Executive Vice President William A. Coley heads the Customer Group. Executive Vice President Steve C. Griffith, Jr. is General Counsel, and Executive Vice President Richard B. Priory heads the Power Generation Group.

Each of these groups was designed along functional lines. Corporate Group departments provide services such as finance, human resources, information services, purchasing and communications. The Customer Group includes groups of the Company that directly deliver power to customers and meet their needs for products and services. The Power Generation Group comprises the parts of Duke Power responsible for energy production. General Counsel includes the Company's legal department, risk management, taxes and public affairs.

In this year's Annual Report the executives heading these groups discuss some of the challenges facing Duke Power and ways we are using the excellence process to help us meet them.

The Corporate Group

William H. Grigg

Vice Chairman of the Board

Year Joined Duke Power: 1963

Responsibilities:

Director, Duke Power Company. Oversees the Corporate Group, which includes Finance; Planning and Operating; Rates and Regulatory Affairs; Corporate Performance; Corporate Communications; Human Resources; Information Technology Services; Procurement, Services and Materials; and Internal Audit. Also reporting to the Corporate Group are Crescent Resources, Inc., Duke Power's real estate development and forest management subsidiary, and Duke Energy Corp., Duke Power's independent power development subsidiary.

Civic Involvement:

Trustee, Johnson C. Smith University; Chairman, Business Advisory Council of the University of North Carolina at Charlotte; Trustee, Fuqua School of Business, Duke University; Commissioner, Charlotte-Mecklenburg Hospital Authority; Chairman, North Carolina Independent College Fund; Second Vice President, Charlotte Chamber of Commerce.

The 1990s will be a decade of monumental change for the electric utility industry. Increased competition, heightened concern for the environment, greater emphasis on energy efficiency and conservation, lower rates of growth in electric demand, new markets and businesses apart from the traditional utility franchise — these factors create unprecedented opportunity and challenge for our Company.

While competition within the electric power industry is not new, it intensified with the Public Utility Regulatory Policies Act of 1978, which enabled independent power producers to build, own and operate certain types of power generation facilities. As a result, more new domestic power generation has been built by independents than by regulated electric utilities in recent years. The 1992 Energy Policy Act levels the playing field by permitting Duke Power and other regulated utilities to compete on a more equal footing with independent producers and cogenerators to build and operate new generating facilities anywhere in this country or the world.

But competition will not be limited to power generation. The Energy Policy Act also mandates open access to transmission lines for the wholesale wheeling of bulk power, creating the potential for a highly competitive wholesale power market. New opportunities will abound for efficient, low-cost producers as protected franchises give way to competitive forces.

In the retail arena, competition may come principally from new technologies. Photovoltaics and fuel cells offer our customers the promise of future options, and a growing array of conservation and load management programs will give them greater control over energy usage and cost.

Heightened environmental concerns led to the 1990 amendments to the Clean Air Act, which placed stricter limits on fossil-fueled power plant emissions. Duke's mix of nuclear and low-sulfur coal complies with the first phase requirements of the Act, but more stringent standards that begin near the end of this decade will increase capital and operating costs significantly. Other environmental requirements will affect how we manage our lakes, dams and hydroelectric units, and how our power plants will be operated and relicensed.

Our Company is actively addressing these changes and more. Innovative strategies to improve cost effectiveness, to provide superior customer service, to protect the environment, and to expand business opportunities are in place to help ensure that our Company continues to achieve its earnings objectives while maintaining competitive prices.

Since 1990, productivity, as measured by kwh sales per employee, has increased by nearly 13 percent, non-fuel operating and maintenance costs per kwh delivered are essentially flat, and the real price of electricity has declined. Yet, we are providing more and better service. Customers can access the Customer Service Center around the clock, demand-side options help customers conserve energy and reduce their power costs, and the reliability of service and fossil plant availability have measurably improved.

Our Company is pursuing new opportunities related to, but beyond, our core utility business. Crescent Resources, Inc. has expanded from a forest products company to a successful developer of its sizable real estate holdings. Duke Energy Corp. led a consortium that purchased majority ownership of an Argentine power plant that is operated by a group led by Duke Engineering & Services, Inc. Duke/Fluor Daniel is building a fossil plant for South Carolina Electric & Gas Co. And Duke Engineering & Services continues to expand its engineering services business around the world.

The new era of change and competition is exciting. We believe that the successful power companies of the future will be those with a skilled, highly motivated team; that plan effectively and innovatively; that give customers timely and quality service at competitive prices; that are good stewards of the environment; and that aggressively take advantage of new electric utility-related opportunities. Duke Power intends to be one of those successful companies.

Duke Power Vice Chairman William H. Grigg, here at Johnson C. Smith University's Biddle Hall, serves on the boards at several universities. With a strong interest in higher education, he also serves as Chairman of the North Carolina Independent College Fund.

THE CUSTOMER GROUP

WILLIAM A. COLEY

Executive Vice President

Customer Group

Year Joined Duke Power: 1966

Responsibilities:

Director, Duke Power Company. Oversees functions charged with delivering power and providing direct customer service, including Nantahala Power and Light Company, water operations and merchandising.

Civic Involvement

Member, Board of Directors, United Way of Central Carolinas; Member, Board of Directors, Charlotte Symphony Orchestra; Member, Board of Advisors, WTVI; Member, Board of Trustees, Charlotte-Mecklenburg Public Library; Member, Executive Committee, McMillan-Spratt Health Care Task Force; Trustee, Queens College; Director, Charlotte Chamber of Commerce; Trustee, Charlotte Latin School.

Duke Power has always stressed citizenship, excellent customer service, and quality in every facet of the business. We're proud of our heritage, but we understand that the level of service needed by our customers today is far higher than that which Duke Power or our industry has ever been able to deliver. Duke's future success depends on our knowing and exceeding the ever-increasing requirements of our customers.

The Customer Group's objective is to meet customer needs 100 percent of the time. That would be a difficult task if each of our 1.7 million customers had exactly the same needs and expectations. It's even more challenging because each customer defines quality in a different way, with different priorities and varying expectations.

Changing needs and expectations mean we must have a continuing dialogue with our customers through personal visits, focus groups, telephone interviews and customer surveys. We have dedicated ourselves to listening to customers and responding to their needs.

By listening we know that our industrial customers place high priority on the quality of their electric service because of the high-technology equipment they use in their plants. They also want assurance that Duke Power will have the capacity to power their future needs. By listening we know that our residential customers are most concerned about the cost of electricity and having easy-to-understand bills. Even so, they too are beginning to focus more on power quality as computers and other electronic equipment become more commonplace in their homes.

Many of our industrial customers are battling increasing pressure from global competition. They compete not only with each other, but also with other producers worldwide. They're looking to Duke to help them compete by keeping the cost of electricity low. They also look to us to help them comply with environmental regulations. We've responded, for example, by demonstrating how electrotechnologies can be used in manufacturing and industrial processes to lower costs while providing superior environmental performance.

Our customers have also told us they want us to be more accessible. We created a central Customer Service Center so they can reach us all day, every day. When our customers said they wanted us to be flexible and responsive to their needs, we streamlined the Customer Group to give more decision-making authority and accountability to employees who are closest to the customers.

Cost is an important issue for all customers. Improving our cost effectiveness helps us meet our objectives of holding down the price of our product while providing growing returns to our shareholders. By managing attrition in our workforce in 1992, we have been able to serve more new customers with fewer employees and still provide superb service.

We know our customers' needs and expectations are constantly changing. Better use of technology and re-engineering our business are two ways we offer our customers greater control and more flexibility today. Tomorrow, we may offer customers the option to buy power in new ways at varying prices, giving them more direct control over their energy costs. Our customers may even be able to select services through their home computer or television.

The Customer Group's objective is to provide superb service at the best possible price. We recognize that the key to achieving our objectives lies in our most important asset — our employees. We're asking our employees to be more creative and innovative, to challenge the way we work, and to work together to serve our customers. In a fast-changing environment, serving our customers' and shareholders' needs cannot be done as we have in the past, so we have embarked on a total quality process. While we remain a regulated industry, we will not depend on regulation to guarantee success. We will be cost-effective, offer competitive products and services, and exceed our customers' expectations. We can succeed only when our customers succeed. Our employees know this and are rallying to the challenge of quality customer service at competitive prices, thereby ensuring a fair return to our shareholders.

Executive Vice President William A. Coley serves as a member of the McMillan-Spratt Health Care Task Force, a body created to examine the delivery of health care in the region. The task force meets periodically at health facilities like Charlotte's Presbyterian Hospital.

STEVE C. GRIFFITH, JR.

Executive Vice President and General Counsel

Year Joined Duke Power: 1964

Responsibilities:

Director, Duke Power Company. Directs Duke Power's Legal, Tax, Risk Management and Public Affairs departments.

Civic Involvement:

Fellow, American Bar Foundation; Chair-elect of the American Bar Association Section of Public Utility, Communication and Transportation Law; Member, North Carolina and South Carolina State Bars; Member, Research Triangle Institute Board of Governors; Member, Board of Visitors, Johnson C. Smith University; Member, Board of Visitors University of North Carolina at Charlotte.

Duke Power General Counsel Steve C. Griffith, Jr. is the Chair-elect of the American Bar Association's Section of Public Utility, Communication and Transportation Law.

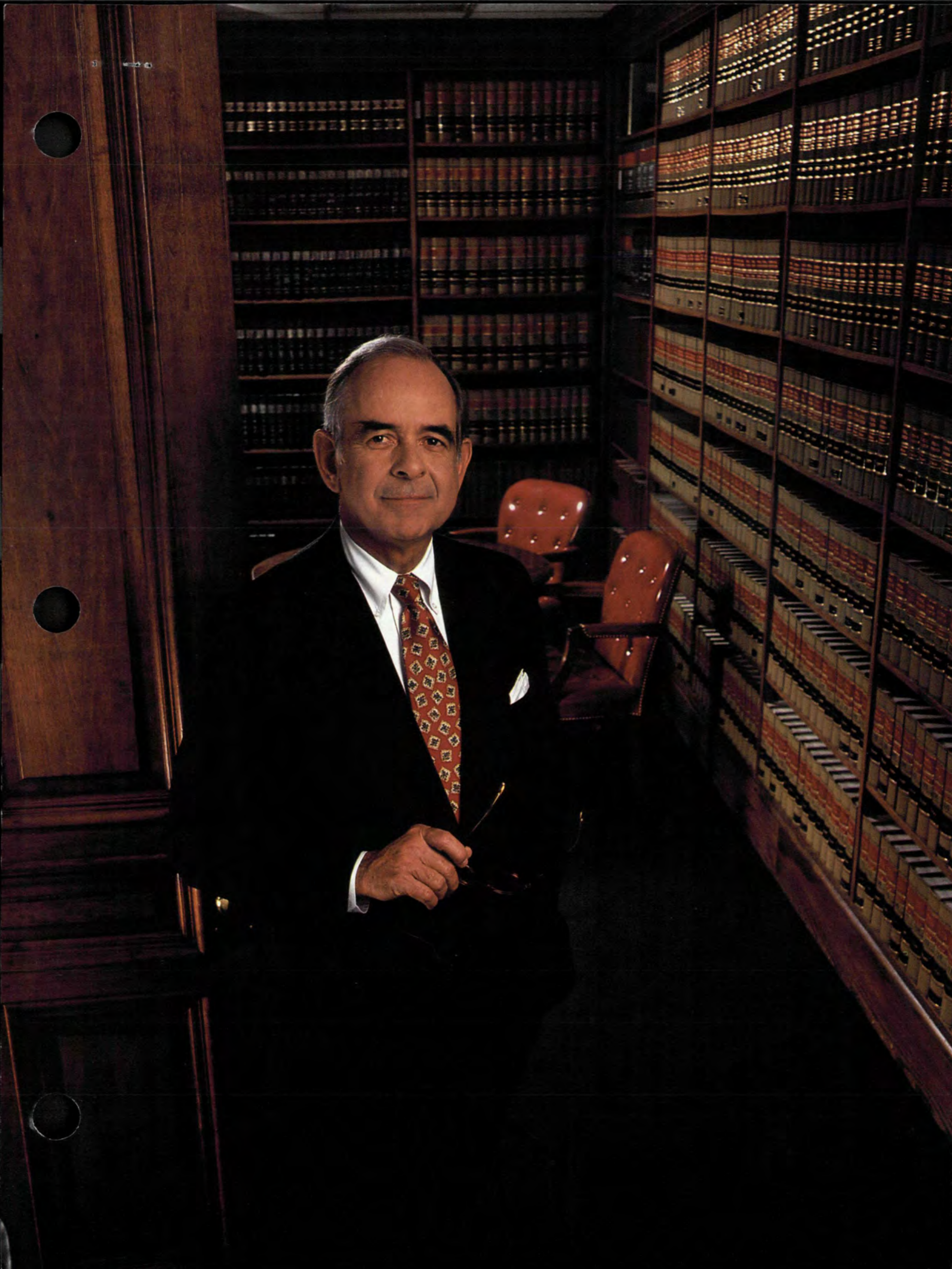
Passage of the Energy Policy Act of 1992 was, to my mind, the biggest event affecting the electric utility industry last year. Duke Power strongly advocated passage of the Act, and we believe that its enactment was in the national interest. Our country is going to need every resource at its disposal to deal with energy-related matters, and the Energy Policy Act broadens the horizon of opportunities available to Duke Power and the nation.

The picture the Act creates depends on how one looks at it. While deregulation is the big buzzword in our industry, the Act is going to give us a little of everything—deregulation, re-regulation, continuation of old regulation and additional new regulation. But the Energy Policy Act is only one of many pieces of legislation and regulation we must address. The Clean Air Act, the Americans with Disabilities Act and the Civil Rights Act are major pieces of legislation that bring their own special regulatory requirements. These issues require Duke Power to work with Congress, the legislatures in the Carolinas and many other public bodies.

However, the Energy Policy Act may be the most significant piece of legislation affecting the industry that Congress has passed in over 50 years. Now that it's law, the Act will impose special challenges on Duke Power. Our strategic plan and quality process are tremendous assets that will put us ahead of the challenges. We're going to face competition in new ways, which will require us to be innovative and nimble in responding to marketplace changes. The status quo does not work well in this new environment. All types of customers are asking for more from Duke Power, not just industrial or commercial customers. Even residential customers are using sophisticated equipment in their homes, and they don't want interruptions of service. We have some customers who say that the reliability of service is more important than its price. We have others who say they must have low prices.

A number of issues impact Duke Power's ability to achieve its objectives. The pricing of the product, demand-side management, compliance with nuclear regulations, and waste disposal and site clean-up are some of these issues. As Duke Power expands its nonregulated business, the Company creates new subsidiaries and negotiates contracts for existing ones. The Company faces more complex tax laws in more jurisdictions, and increasingly difficult insurance claims and workers compensation issues.

Succeeding in the electric utility industry is far tougher today than it was last year. As we move forward through the 1990s, the ramifications of new and changing laws and regulations affecting our business will be even more challenging. Our role is to help create positive situations in which the Company can achieve the goals in the strategic plan. The Energy Policy Act is going to create opportunities for new business, and we have subsidiaries that are aggressively scouting new business. The advantage will go to companies that can move quickly and wisely in this new environment. We intend to make that happen for the ultimate benefit of our customers, employees and shareholders.



The Power Generation Group

Richard B. Priory
Executive Vice President
Power Generation Group
Year Joined Duke Power: 1976

Responsibilities:
Director, Duke Power Company. Heads departments responsible for engineering, constructing, operating and maintaining Duke Power's generating plants. Also directs two Duke Power affiliates, Duke Engineering & Services, Inc. and Duke/Fluor Daniel.
Civic Involvement:
University of North Carolina at Charlotte Board of Visitors; President, Board of Trustees, Science Museums of Charlotte; Chairman, Charlotte-Mecklenburg Education Foundation; Member, Charlotte Mecklenburg Public Broadcasting Authority.

For many of its 88 years Duke Power successfully designed, built and operated electric generating stations with effective, but separate, teams. The Power Generation Group, formed in late 1991, combines and strengthens these design/build/operate teams.

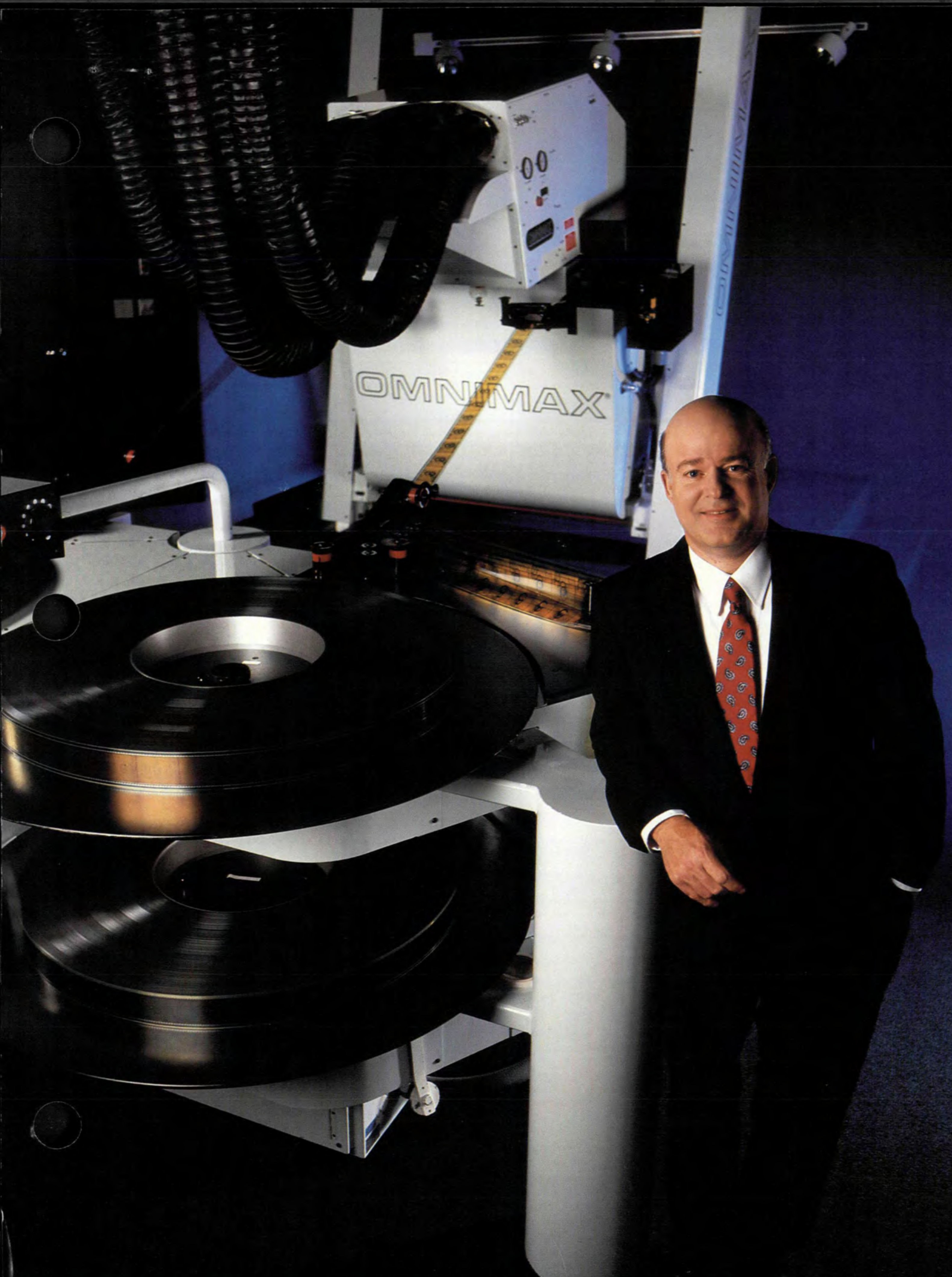
In 1992, Power Generation progressed on its journey to excellence. Excellence stresses doing the right things right through strategic planning, better use of measurement and data, enhanced teamwork, focus on customer satisfaction, and continuous process improvement. All Power Generation employees are receiving initial training in the excellence process. Quality Steering Teams in place at every location lead us on this important journey. Employees are empowered and encouraged to generate work improvement ideas. When fully implemented, the excellence process will bring about substantial gains in both employee satisfaction and team performance.

Now, fortified with a new organization and culture, what major challenges do we face? With a strategy to maximize performance of existing generating plants, here are the major jobs ahead:

- Successfully implement the excellence process in all areas of Power Generation. As we embrace continuous improvement, our work processes will benefit. This is essential if we are to become world-class in electric generation.
- Design and build the 1,184-megawatt Lincoln Combustion Turbine Station. With operation to begin in 1995, the plant will help meet the peak demand needs of our customers and help avoid more costly base-load plants.
- Replace steam generators at McGuire Nuclear Station and Unit 1 of Catawba Nuclear Station beginning in 1995. Replacement is complex and extensive. It will require exceptional teamwork and will benefit from our new organization and excellence process.
- Begin the process of extending the 40-year operating licenses of Oconee, McGuire and Catawba nuclear stations. We plan to extend the licenses for another 20 years to maximize the benefit from our largest investments. Oconee's license doesn't expire until 2013, but it may be the nation's first nuclear plant to test the relicensing process. We can't prepare too soon.
- Ensure our fossil plants are available to generate more electricity. We'll be counting on additional contributions from them to meet demand and to avoid building base-load plants. Their recent refurbishment and the excellence process should result in new levels of performance.
- Relicense our hydroelectric facilities. New laws challenge us to strike a responsible environmental and financial balance. New laws on dam stability will require structural improvements to increase existing safety margins.
- Implement the provisions of the 1990 Clean Air Act at our fossil stations. Although we meet the Phase I requirements of the Act, the future effects will be felt. We must add continuous emission monitoring equipment and low nitrous oxide fuel burners starting in 1993. We may also need expensive desulfurization systems on some units near the end of the decade.
- Capture more opportunities for the two affiliated companies that report to the Power Generation Group. For Duke/Fluor Daniel, our coal-fired plant engineering, construction and operating company, we want to increase market share as non-utility and utility generators turn to coal-fired generation. For Duke Engineering & Services, formed to provide engineering, technical and management services to utilities and related businesses, we want to continue its aggressive growth pattern.

The work facing us is the most challenging ever; however, our Power Generation team is better equipped than ever. Our organization is more aligned and focused on our goals, and our excellence process is the rallying point for teamwork — the special ingredient that gives us the competitive edge. We are excited about the challenges and our prospects for success.

Executive Vice President Richard B. Priory is President of the Board of Trustees of the Science Museums of Charlotte which includes Discovery Place, a hands-on science and technology museum.


OMNIMAX

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	$3,7[illegible]
Electric expenses				
Operation				
Fuel used in electric generation (Note 1)		**659,593**	657,725	660,298
Net interchange and purchased power (Notes 3 and 15)		**540,840**	545,840	565,034
Wages, benefits and materials		**636,729**	622,121	564,624
Maintenance of plant facilities		**403,162**	354,679	403,831
Depreciation and amortization (Notes 1 and 11)		**491,339**	431,624	405,762
General taxes		**215,493**	204,688	197,087
Income taxes (Notes 1 and 4)		**289,633**	293,460	265,712
Total electric expenses		**3,236,789**	3,110,137	3,062,348
Electric operating income		**724,695**	706,823	642,783
Other income (Notes 1, 4 and 14)				
Allowance for equity funds used during construction		**15,476**	50,704	79,176
Other, net		**83,216**	102,884	54,210
Income taxes — other, net		**(27,475)**	(25,472)	(15,284)
Income taxes — credit		**13,790**	22,789	28,638
Total other income		**85,007**	150,905	146,740
Income before interest deductions		**809,702**	857,728	789,523
Interest deductions				
Interest on long-term debt		**265,646**	274,662	260,333
Other interest		**41,736**	18,834	[illegible]
Allowance for borrowed funds used during construction (credit) (Note 1)		**(5,763)**	(19,391)	[illegible]
Total interest deductions		**301,619**	274,105	251,335
Net income		**508,083**	583,623	538,188
Dividends on preferred and preference stock		**56,407**	54,683	52,616
Earnings for common stock		**$ 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.

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 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)
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.

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	$11,8[illegible]
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 investments	367,217	286,793
Current assets		
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	3[illegible]
Canceled construction projects (Note 11)	28,889	67,302
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

	1992	1991
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
Notes 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	1[illegible]
Total deferred credits and other liabilities	589,910	4[illegible]
Commitments and contingencies (Note 13)		
Total capitalization and liabilities	$10,801,794	$10,470,615

See Notes to Consolidated Financial Statements.

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
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	324,104
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.

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 [illegible]t 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 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 establishe[illegible] for the decontamination and decommissioning of the DO[illegible]a-nium 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 41.)

F. Income Taxes

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.

H. Fuel Cost Adjustment Procedures

Fuel costs are reviewed semiannually in the wholesale and South Carolina retail jurisdictions, with provisions for changing such c[illegible] 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 $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.

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

(continued from page 27)

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 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 7½-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 jurisdicti[illegible]e Company recovers the costs of purchased energy and a po[illegible]f purchased capacity. The portion of costs not currently recovered through rates is being accumulated, and the Company is recording a net of 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	[illegible]
Income taxes related to electric expenses			
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,[illegible]4)
Total income tax expense	$303,318	$296,143	$2[illegible]

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, $[illegible]1,000 for 1991 and $38,911,000 for 1990.

Total deferred income taxes were $55,780,000 for 1992, $38,664,000 for 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 [illegible]ar, $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.

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
Amount 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	$285,500	$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%

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 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, 6¾% Convertible Series AA at 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	$ [illegible]
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
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
Preference Stock	100	1,500,000	1,500,000

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.[illegible] B (Preferred Stock A)	1992	800,000	$ 20,000	$ —
6.[illegible] 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	—
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 fund 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 $[illegible]00 in 1993 and $3,000,000 in 1994, 1995, 1996 and 1[illegible]ome 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 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 ½%	1992	$ —	$ 50,000
4 ¼% B	1992	—	50,000
6.06%-6.23%	1994	81,700	81,700
6.47%-6.60%	1995	40,300	40,300
4 ½%	1995	40,000	40,000
6.59%	1996	3,000	3,000
7 ⅞%	1996	100,000	100,000
7 ½% B	1997	—	100,000
5 ⅜%	1997	72,600	72,600
5 ⅝%	1997	100,000	—
6 ⅜%	1998	68,500	68,500
7%	1999	56,075	56,075
7.5%	1999	100,000	—
8% B	1999	—	64,739
6 ¼%	1999	65,000	—
7%	2000	100,000	—
7% B	2000	100,000	—
8 ½%	2000	—	69,244
8 ⅝% B	2000	—	95,635
7[illegible]	2001	97,900	97,900
7[illegible]	2001	38,050	38,050
7 ¾%	2002	78,100	78,100
7 ⅜% B	2002	67,900	67,900
7 ¾%	2003	94,872	94,872
8 ⅛% B	2003	—	98,050
8%	2004	75,000	—

Series	Year Due	1992	1991
(continued)			
9 ¾%	2004	$ —	$ 95,623
7.37%-7.41%	2004	100,000	—
7%	2005	200,000	—
9 ½%	2005	—	92,800
8 ⅜%	2006	—	96,850
8 ⅛%	2007	119,500	119,500
9 ⅜%	2008	—	120,610
10 ⅛% B	2015	—	50,000
9%	2016	175,000	175,000
8 ½%	2017	150,000	150,000
9 ⅝%	2020	200,000	200,000
10 ⅛% B	2020	150,000	150,000
8 ¾%	2021	150,000	150,000
8 ⅜% B	2021	150,000	150,000
8 ⅝%	2022	100,000	—
8.95%	2027	15,925	15,994
Pollution-Control			
9 ⅛%	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.

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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.

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.

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 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.

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)	
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 investments and cash equivalents, common stocks, real estate investments 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 age. For 1990, an increase of 6.5 percent was assumed for all participants. 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.

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 at 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 retirees must have at least ten years of service to 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 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 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 as 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 $11,900,000 and $10,200,000, respectively.

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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		$ [illegible]44
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)
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 investments and cash equivalents, common stocks, real estate investments 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 Lives Reserve assets.

The assumed health care cost trend rate for 1992 was approximately 14 percent. Medical trends for 1993 and forward [illegible]se .5 percent to 1 percent per year. The trend rate of 5.5 pe[illegible]n 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 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 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 $[illegible]lion amount is subject to indexing for inflation. This amou[illegible]ther subject to a surcharge of 5 percent (which is included [illegible] 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

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 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 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 $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 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 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 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 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.

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 Statements of Income. The income is primarily from dividends and interest on securities. The taxes associated 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 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.

Independent Auditors' Report

Duke Power Company:

We have audited the accompanying consolidated balance sheets and the consolidated statements of capitalization of Duke Power Company and subsidiaries (the Company) as of December 31, 1992 and 1991, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1992. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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.

Deloitte & Touche

Deloitte & Touche
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. 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 mangement 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 L. Hauser

David L. Hauser
Controller

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 one-time 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 compared to 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 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 39.)

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 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 39.)

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

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 Federal Energy Regulatory 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 39.) 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 "double 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 redeem $229 million of preferred stock. As of December 31, 1992, the Company's bonds were rated "double 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 purchases to satisfy the requirements of the various stock purchase plans.

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 requirements for the stock split and for the conversion rights of preference stock.

The Company's embedded cost of long-term debt for 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 the return on purchased capacity levelization,

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 additi[illegible]formation on the refund, see Liquidity and Resources "[illegible]tters," page 37.)

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 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 Ca[illegible]a Nuclear Station and the costs associated with contractual p[illegible]s of capacity from the other Catawba joint owners. The co[illegible]s 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 costs 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 38, are resolved in the Company's favor. (For additional information with respect to purchased capacity levelization, see Note 3 to the Consolidated Financial Statements.)

Meeting Future Power Needs

The Company's strategy for meeting customers' 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.

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.

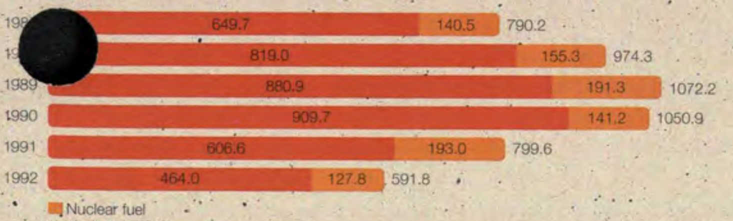
The purchase of capacity and energy is also an integral part of meeting future power needs. The Company currently has under contract 500 megawatts of capacity from other generators of electricity.

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.

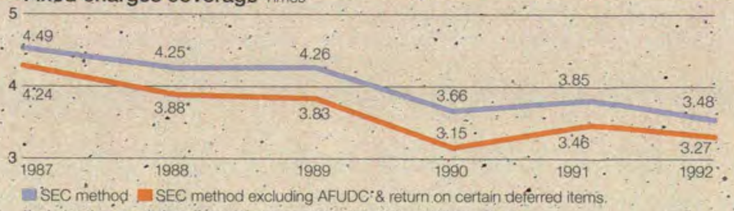
The Company has been engaged in a concentrated effort to

Construction costs* Millions of dollars



*Including AFUDC.

Fixed charges coverage Times



*Includes the cumulative effect of the accounting change for unbilled revenues.

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 this 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 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 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 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.

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 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 $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 judgment 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

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, 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 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.

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 1990. (a) (b) Highlights of selected subsidiaries are presented below.

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. (dollars in thousands)

	1992	1991	1990
Assets net of liabilities	$ 42,910	$ 39,384	$36,663
Net income	$ 3,526	$ 2,721	$ 2,777
Number of employees (c)	191	194	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. (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 net 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 non-utility operations includes elimination of intercompany profit of $1,211,000, after tax.
(c) Full-time employees.

SELECTED FINANCIAL DATA

	1992	1991	1990	1989	1988
Condensed consolidated statements of income (thousands)					
Electric revenues (a)	**$ 3,961,484**	$ 3,816,960	$ 3,705,131	$3,692,955	[illegible]
Electric expenses (a)	**3,236,789**	3,110,137	3,062,348	2,988,355	3,014,859
Electric operating income	**724,695**	706,823	642,783	704,600	629,551
Other income	**85,007**	150,905	146,740	101,826	46,211
Income before interest deductions	**809,702**	857,728	789,523	806,426	675,762
Interest deductions	**301,619**	274,105	251,335	234,815	227,631
Cumulative effect of accrual of unbilled revenues	**—**	—	—	—	102,255
Net income	**508,083**	583,623	538,188	571,611	550,386
Dividends on preferred and preference stock	**56,407**	54,683	52,616	52,477	53,329
Earnings for common stock	**$ 451,676**	$ 528,940	$ 485,572	$ 519,134	$ 497,057
Common stock data (b)					
Shares of common stock — year-end (thousands)	**204,859**	204,699	202,584	202,563	202,544
— average (thousands)	**204,819**	203,431	202,570	202,554	202,533
Per share of common stock					
Earnings (c)	**$2.21**	$2.60	$2.40	$2.56	$2.45
Dividends	**$1.76**	$1.68	$1.60	$1.52	$1.44
Book value — year-end	**$20.26**	$19.86	$18.84	$18.05	$17.01
Market price — high-low	**$37½-31⅜**	$35-26¾	$32⅜-25½	$28¼-21⅜	$24½-21⅛
— year-end	**$36⅛**	$35	$30⅝	$28 1/16	$23⅛
Balance sheet data (thousands)					
Total assets	**$10,801,794**	$10,470,615	$10,083,507	$9,542,398	$8,890,605
Long-term debt	**$ 3,202,437**	$ 3,159,575	$ 3,102,746	$2,822,442	$2,728,794
Preferred stock with sinking fund requirements	**$ 279,519**	$ 228,650	$ 239,800	$ 247,825	$ 255,850
Electric and other statistics					
Kilowatt-hour sales (millions)					
Residential	**17,789**	17,918	17,221	16,895	[illegible]
General service	**15,818**	15,586	15,032	14,206	[illegible]
Industrial	**27,041**	26,270	25,894	25,934	25,154
Other energy and wholesale (a)(d)	**10,360**	10,132	10,468	11,969	11,615
Total kilowatt-hour sales billed	**71,008**	69,906	68,615	69,004	67,147
Unbilled kilowatt-hour sales (e)	**34**	(19)	(540)	370	165
Total kilowatt-hour sales	**71,042**	69,887	68,075	69,374	67,312
Residential customer data					
Average annual KWH use	**12,427**	12,710	12,444	12,459	12,614
Average revenue billed per KWH	**7.38¢**	7.10¢	7.07¢	7.09¢	7.20¢
Sources of energy (millions of KWH)(f)					
Generated — Coal	**28,999**	26,455	27,262	26,175	23,930
— Nuclear (g)	**48,238**	49,328	44,649	47,773	47,934
— Hydro (h)	**1,834**	1,545	1,879	1,520	402
— Oil and gas	**5**	7	53	27	32
Total generation	**79,076**	77,335	73,843	75,495	72,298
Purchased power and net interchange (a)	**1,403**	587	1,531	1,158	1,385
Total output	**80,479**	77,922	75,374	76,653	73,683
Less: Other Catawba joint owners' share	**14,313**	12,280	11,735	12,566	12,166
Plus: Purchases from other Catawba joint owners	**9,466**	8,525	8,658	9,809	10,244
Total sources of energy	**75,632**	74,167	72,297	73,896	71,761
Line loss and Company usage	**4,590**	4,280	4,222	4,522	4,449
Total kilowatt-hour sales	**71,042**	69,887	68,075	69,374	67,312
System average heat rate	**9,974**	9,996	10,007	10,013	10,021
System load factor	**60.0%**	59.4%	59.9%	61.8%	59.8%

(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 t[illegible]s 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.
(d) Includes sales to Nantahala Power and Light Company.
(e) Includes the restatement of unbilled kilowatt-hours for 1988.
(f) Does not include operating statistics of Nantahala Power and Light Company.
(g) Includes 100% of Catawba generation.
(h) 1991 includes KWH of the Bad Creek Hydroelectric Station prior to commercial operation.

SELECTED FINANCIAL DATA

Long-Term Financings

To meet its capital requirements, the Company has financed with long-term debt and equity securities and has raised additional capital through other types of financings. Proceeds generated from financings from 1990 through 1992 were as follows (dollars in thousands):

	1992 Net proceeds	1991 Net proceeds	1990 Net proceeds
Common stock (2,100,087 shares issued April 1 - November 30)		$ 48,014	
Preferred stock			
Preferred stock (5.95% - 7.85% dividend rates)	$ 281,089		
Auction Series A, $100 par (750,000 shares issued October 16)			$ 73,875
Total preferred stock	281,089		73,875
Long-term debt			
First and refunding mortgage bonds			
Long-term debt (5⅝% - 8⅝% interest rates)	827,275		
Medium-Term Notes (Issued various dates: January 17 - January 22)	99,375		
8¾% Series due 2021 (Issued March 7)		144,018	
8⅜% Series B due 2021 (Issued December 5)		145,760	
Medium-Term Notes (Issued various dates: December 4 - December 13)		124,519	
9⅝% Series due 2020 (Issued February 13)			197,258
10⅛% Series B due 2020 (Issued May 8)			148,035
Pollution-control series			41,187
Total long-term debt	926,650	414,297	386,480
Total financings	$1,207,739	$462,311	$460,355

Quarterly Financial Data

Dollars in Thousands (except per-share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
1992 by quarter					
Electric Revenues	$981,330	$899,319	$1,139,525	$941,310	$3,961,484
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
Earnings Per Share	$0.45	$0.36	$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.

Stock Market Information

The Company had 125,881 holders of record of common stock as of December 31, 1992, and 119,896 holders as of December 31, 1991. During 1992, approximately 57,340,600 shares of common stock were traded, compared with 65,928,000 during the previous year. The Company's common stock prices, as quoted in the New York Stock Exchange Composite Transactions, and dividends paid were as follows:

	Dividends Per Share	Stock Price Range High	Stock Price Range Low
1992 by quarter			
Fourth	$0.45	$37½	$34⅝
Third	0.45	36½	34⅛
Second	0.43	34⅝	32
First	0.43	35	31⅜

	Dividends Per Share	Stock Price Range High	Stock Price Range Low
1991 by quarter			
Fourth	$0.43	$35	$30⅛
Third	0.43	32½	27⅜
Second	0.41	29⅜	27¼
First	0.41	30¾	26¾

BOARD OF DIRECTORS

William S. Lee
Chairman of the Board, President and Chief Executive Officer [1,5,6]

Dr. Robert L. Albright
President
Johnson C. Smith University [2]

G. Alex Bernhardt
President and Director
Bernhardt Furniture Company [2]

Crandall C. Bowles
Executive Vice President, Growth and Development
Springs Industries, Inc. [4]

William A. Coley
Executive Vice President, Customer Group [1]

John L. Fraley
Chairman Emeritus Carolina Freight Corporation [3]

Steve C. Griffith, Jr.
Executive Vice President and General Counsel [1]

William H. Grigg
Vice Chairman of the Board, Corporate Group [1,5]

Paul H. Henson
Chairman Kansas City Southern Industries, Inc. [3,4,6]

Dr. George R. Herbert
Vice Chairman and President Emeritus Research Triangle Institute [2]

George Dean Johnson, Jr.
General Partner
WJB Video [5]

James V. Johnson
Retired Vice Chairman and Director, Public Affairs
Coca-Cola Bottling Co. Consolidated [2]

W.W. Johnson
Chairman Executive Committee
NationsBank Corporation [5,6]

Dr. Max Lennon
President
Clemson University [4]

Buck Mickel
Chairman and Chief Executive Officer
RSI Corporation [3,4]

Reece A. Overcash, Jr.
Chairman and Chief Executive Officer
Associates First Capital Corp. [3,5,6]

Richard B. Priory
Executive Vice President, Power Generation Group [1]

1. Management Committee
2. Audit Committee
3. Compensation Committee
4. Corporate Performance Review Committ
5. Finance Comm
6. Nominating Com

Retiring Directors

Warren H. Owen
Executive Vice President and Assistant to the Chairman of the Board of Duke Power Company

James C. Self, Sr.
Chairman of the Executive Committee, Greenwood Mills, Inc.
Trustee, The Duke Endowment

OFFICERS

William S. Lee
Chairman of the Board, President and Chief Executive Officer

William H. Grigg
Vice Chairman of the Board, Corporate Group

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

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 Counsel

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, 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

David L. Hauser
Controller

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, 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 and Hydro Generation Department

Ted C. McMeekin
Vice President, McGuire Nuclear Site

John P. O'Keefe
Vice President, Taxes

Richard J. Osborne
Vice President and Chief Financial Officer

William F. Reinke
Vice President, System Planning and Operating

W. 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

Principal Subsidiaries and Affiliates

Ronald F. Green
President
Duke/Fluor Daniel

E. N. Hedgepe
President and Chai e Board
Nantahala Power and Light Company

William S. Lee
President
Church Street Capital Corp.

John F. Norris, Jr.
President
Duke Engineering & Services, Inc.

Richard C. Ranson
Chairman
Crescent Resources, Inc.

M. Rhem Wooten, Jr.
President
Duke Energy Corp.

Retiring Officers

The following officers have retired:

Warren H. Owen
Executive Vice President and Assistant to the Chairman of the Board of Duke Power Company

J. Kenneth Clark
Vice President, Corp Communications

Robert L. Dick
Vice President, Corporate Excellence

INVESTOR INFORMATION

Corporate headquarters
422 South Church Street
Charlotte, N.C. 28242-0001
(704) 594-0887

Notice of annual meeting
The 1993 Annual Meeting of Duke Power Shareholders will be:

Date: Thursday, April 29, 1993
Time: 10:00 a.m.
Place: Duke Power Company
O.J. Miller Auditorium
Electric Center
526 South Church Street
Charlotte, N.C.

Stock exchange listing
Duke Power's common stock is listed on the New York Stock Exchange. The trading symbol is DUK. The previous day's closing price is listed in daily newspapers as DukePwr or DukeP.

Many issues of preferred stock are listed on the New York Stock Exchange. Quotations for these issues are listed only when the stock is traded and follow the common stock listing in the newspaper.

Financial publications
Upon request, the Company will provide the following without charge:

1992 Annual Report on Form 10-K as filed with the Securities and Exchange Commission

Statistical Supplement to the 1992 Annual Report to Shareholders

Audiotape recording of excerpts from the 1992 Annual Report to Shareholders

The Company produces a report to shareholders in the first, second and third quarters.

Dividend payment
Duke Power has paid quarterly cash dividends on its common stock for 66 consecutive years.

Dividends on the Company's common and preferred stock in 1993 are expected to be paid on:

March 16, June 16, September 16 and December 16

Securities ratings

Rating Agency	Bonds	Preferred Stock	Commercial Paper
Duff & Phelps	AA-	A+	
Fitch	AA	AA-	F-1+
Moody's	Aa2	aa2	P-1
Standard & Poor's	AA-	A+	A-1+

Shareholder inquiries
Shareholders with questions about their stock accounts, legal transfer requirements, address changes, replacement dividend checks, replacement of lost certificates or other services may write:

Investor Relations
Duke Power Company
P.O. Box 1005
Charlotte, N.C. 28201-1005

or call:

(800) 488-3853 toll free or
(704) 382-3853 Charlotte or
(704) 382-3814 fax

Investor services
The Stock Purchase and Dividend Reinvestment Plan is available to all shareholders of record and Duke Power electric customers. This provides a convenient way to buy common shares without brokerage fees.

Direct Deposit of Dividends automatically credits dividends to shareholders' bank accounts on the dividend payment date.

Small Share Repurchase Service offers investors with 99 or fewer shares an opportunity to sell their shares back to the Company without paying brokerage fees as long as the sale closes the account.

Stock transfer
Duke Power maintains shareholder records and acts as Transfer Agent for the Company's common and preferred stock issues.

Signatures required for transfer must be guaranteed by a participant in an approved medallion program. Other guarantees or a notary's acknowledgement are not acceptable.

We recommend all certificates be mailed by registered mail, insured for two percent of the market value, to Duke Power Company Investor Relations.

Registrar
First Union National Bank of North Carolina
Charlotte, N.C.

Bondholder inquiries
Questions concerning replacement interest checks, bond tax information, legal transfers and other account information relating to bond ownership should be directed to:

Morgan Guaranty Trust Company of New York
Corporate Trust Operations Department
Tellers and Mail Unit
Basement A
55 Exchange Place
New York, N.Y. 10260-0023
(212) 235-0900

Bondholders needing further assistance should contact Duke Power Investor Relations.

DUKE POWER COMPANY 422 SOUTH CHURCH STREET CHARLOTTE, NORTH CAROLINA 28242-0001

Bulk Rate
U.S. Postage
PAID
Charlotte, N.C.
Permit No.

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, 1992

☐ 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 **(State or other jurisdiction of incorporation or organization)**	**56-0205520** **(IRS Employer Identification No.)**
422 South Church Street **Charlotte, North Carolina** **(Address of principal executive offices)**	**28242-0001** **(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, par value $100	
8.20% Series G	New York Stock Exchange
7.80% Series H	New York Stock Exchange
8.28% Series K	New York Stock Exchange
Preferred Stock A, par value $25	
7.72%, 1992 Series	New York Stock Exchange
First and Refunding Mortgage Bonds	
7⅜% Series B Due 2001	New York Stock Exchange
7¾% Series Due 2002	New York Stock Exchange
7⅜% Series B Due 2002	New York Stock Exchange
7¾% Series Due 2003	New York Stock Exchange
8⅛% Series Due 2007	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 February 23, 1993 .... $7,735,537,493

Number of shares of Common Stock, without par value, outstanding at February 23, 1993 204,859,339

Documents incorporated by reference:

The registrant is incorporating herein by reference certain sections of its proxy statement relating to the 1993 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, 1992

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DUKE POWER COMPANY

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 4,800,000 and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville, Spartanburg and Anderson in South Carolina. During 1992, the Company's electric revenues amounted to approximately $4.0 billion, of which about 70% was derived from North Carolina and about 30% from South Carolina. The Company ranks seventh 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. 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 1,684,000 retail customers in more than 200 cities, towns and unincorporated communities in North Carolina and South Carolina. Electricity is sold through contractual arrangements to North Carolina Municipal Power Agency Number 1 (NCMPA), North Carolina Electric Membership Corporation (NCEMC), Saluda River Electric Cooperative Inc. (Saluda) and Piedmont Municipal Power Agency (PMPA), each of which has purchased from the Company portions of the Catawba Nuclear Station (collectively, the Other Catawba Joint Owners). All constituent entities of the Other Catawba Joint Owners were formerly wholesale municipal or cooperative customers of the Company. Electricity is also sold at wholesale to 9 other incorporated municipalities and to several private utilities. The Company renders electric service in a total of 56 counties and is the principal supplier of electric energy in 44 of these counties.

The Company's service area is undergoing increasingly diversified industrial development. The textile, furniture and chemical industries are of major significance to the economy of the area, and other industrial activity includes the manufacture of metal products, paper and allied products, food 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 $482 million of the Company's revenues for 1992, representing 12% of electric revenues and 41% of electric industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability at December 31, 1992, its sources of electric energy for 1992, and certain information presently projected for 1993:

Source	Generating Capability — KW(a) Actual December 31, 1992	Generating Capability — KW(a) Projected December 31, 1993	Generation — KWH (millions) (d) Actual 1992
Coal	7,377,000	7,548,000	28,999
Nuclear (b)	7,054,000	7,054,000	48,238
Hydro and other	3,281,000(c)	3,281,000(c)	1,839
Total (b)	17,712,000	17,883,000	79,076
Less: Other Catawba Joint Owners' share			14,313
Plus: Purchases from Other Catawba Joint Owners			9,466
Purchased power and net interchange			1,403
Total			75,632

(footnotes on next page)

(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 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 stations 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 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 retail rates, was approved by FERC and became effective in April 1992.

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 the 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 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 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

approval by the NCUC. The Company's current plan reduces supply side requirements in excess of 2,200 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.

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.

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 87½% 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% 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 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 approved by the Company's retail regulatory commissions (see Note 3, "Notes to Consolidated Financial Statements"). Although the Other Catawba 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 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			Average Cost per Million BTU on a Burned Basis		
	Year Ended December 31			Year Ended December 31		
	1992	1991	1990	1992	1991	1990
Coal	36.7%	34.2%	36.9%	174.10¢	179.29¢	180.61¢
Nuclear	61.0	63.8	60.5	52.52	55.00	55.65
Oil and Gas	—	—	—	—	—	—
All Fuels (cost based on weighted average)	97.7	98.0	97.4	96.05	96.48	101.14
Hydroelectric*	2.3	2.0	2.6			
	100.0%	100.0%	100.0%			

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

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. 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 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, 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 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: 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.

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 Practices Acts, promissory estoppel and patterns of racketeering activities prohibited by the Racketeer Influenced and Corrupt Organizations 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 the outages to accomplish replacement, punitive or treble damages, and attorneys' fees.

The NRC 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 (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 management's 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. 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.

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.

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 $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

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 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 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% for 52 weeks, and 67% 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 retrospective 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 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. 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. 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.

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.

Subsequent Events

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

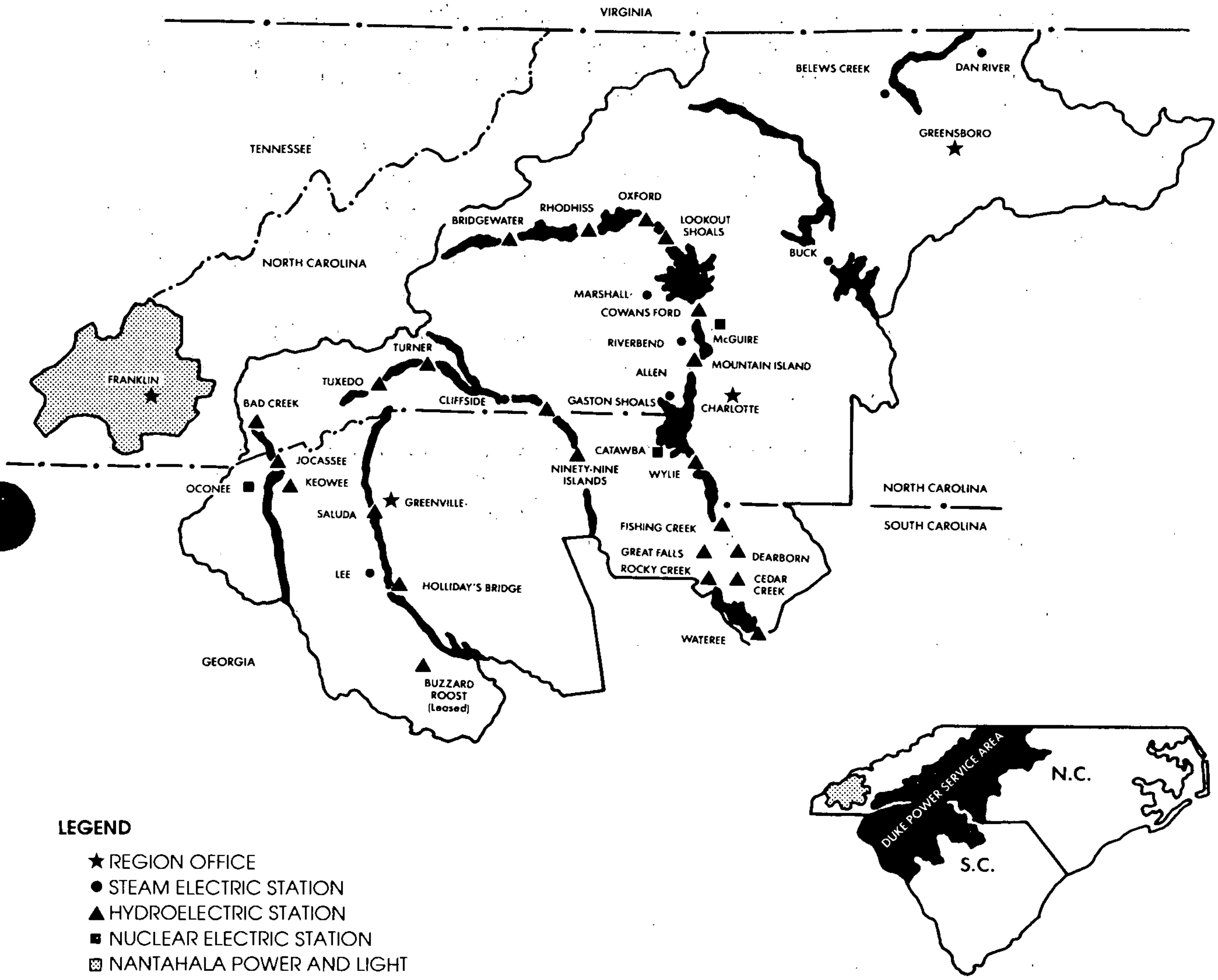
On February 23, 1993 the Company called for redemption $175,000,000 principal amount of its First and Refunding Mortgage Bonds, 9% Series Due 2016. To provide funds for such redemption, the Company has entered into an agreement to sell $200,000,000 principal amount of First and Refunding Mortgage Bonds, 7⅜% Series Due 2023.

In addition, the Company called for redemption on February 25, 1993 $100,000,000 principal amount of its First and Refunding Mortgage Bonds, 7⅞% Series Due 1996 and $78,100,000 principal amount of its First and Refunding Mortgage Bonds, 7¾% Series Due 2002. The Company sold $100,000,000 principal amount of First and Refunding Mortgage Bonds, 6⅝% Series B Due 2003 and has entered into an agreement to sell $75,000,000 principal amount of First and Refunding Mortgage Bonds, 5⅞% 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 First and Refunding Mortgage Bonds, 6⅜% 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.

Duke Power Service Area



DUKE POWER COMPANY
OPERATING STATISTICS

	Year Ended December 31				
	1992	**1991**	**1990**	**1989**	**1988**
Sources of Electric Energy					
Millions of kilowatt-hours:					
Generated — net output:					
Coal	28,999	26,455	27,262	26,175	23,930
Nuclear (A)	48,238	49,328	44,649	47,773	47,934
Hydro	1,834	1,545	1,879	1,520	402
Oil and gas	5	7	53	27	32
Total generation	79,076	77,335	73,843	75,495	72,298
Purchased power and net interchange (B)	1,403	587	1,531	1,158	1,385
Total output	80,479	77,922	75,374	76,653	73,683
Less: Other Catawba Joint Owners' share	14,313	12,280	11,735	12,566	12,166
Plus: Purchases from Other Catawba Joint Owners	9,466	8,525	8,658	9,809	10,244
Total sources of energy	75,632	74,167	72,297	73,896	71,761
Line loss and company usage	(4,590)	(4,280)	(4,222)	(4,522)	(4,449)
Total energy sales (C)	71,042	69,887	68,075	69,374	67,312
Average Cost Per Ton of Coal Burned	$43.47	$45.21	$45.49	$45.13	$44.27
Electric Energy Sales					
Millions of kilowatt-hours:					
Residential	17,789	17,918	17,221	16,895	16,744
General service	15,818	15,586	15,032	14,206	13,634
Industrial					
Textile	11,685	11,315	11,130	11,443	11,134
Other	15,356	14,955	14,764	14,491	14,020
Wholesale and other energy sales (B)(D)	10,360	10,132	10,468	11,969	11,615
Total energy sales billed	71,008	69,906	68,615	69,004	67,147
Unbilled energy sales	34	(19)	(540)	370	165
Total energy sales (C)	71,042	69,887	68,075	69,374	67,312
Electric Revenue					
Thousands of dollars:					
Residential	$1,312,227	$1,272,322	$1,216,945	$1,198,705	$1,205,471
General service	964,853	921,337	886,480	851,422	833,709
Industrial					
Textile	482,172	475,191	476,493	493,933	495,100
Other	696,413	668,765	654,551	653,830	651,420
Wholesale and other energy sales (B)(D)	460,849	441,777	391,803	449,545	463,793
Other electric revenues	44,970	37,568	78,859	45,520	(5,083)
Total electric revenues (C)	$3,961,484	$3,816,960	$3,705,131	$3,692,955	$3,644,410
Number of Customers — End of Year					
Residential	1,439,845	1,415,605	1,391,336	1,362,118	1,339,206
General service (E)	227,675	222,917	224,642	216,960	210,122
Industrial					
Textile	1,390	1,385	1,398	1,408	1,424
Other	7,314	7,255	7,325	7,310	7,232
Wholesale and other energy sales (B)	7,773	7,605	7,405	7,249	7,133
Total customers	1,683,997	1,654,767	1,632,106	1,595,045	1,565,117
Residential Customer Statistics					
Average number for year	1,431,403	1,409,775	1,383,799	1,356,088	1,327,452
Average annual use — KWH	12,427	12,710	12,444	12,459	12,614
Average annual billing	$916.74	$902.50	$879.42	$883.94	$908.11
Average Annual Billed Revenue Per KWH					
Residential	7.38¢	7.10¢	7.07¢	7.09¢	7.20¢
General service	6.10¢	5.91¢	5.90¢	5.99¢	6.11¢
Industrial	4.36¢	4.35¢	4.37¢	4.43¢	4.56¢
Wholesale and other energy sales (B)	4.45¢	4.36¢	3.74¢	3.76¢	3.99¢

(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.

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 Counsel
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, 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 President, 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.

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.

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 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 Note 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:

Common Stock	Dividends Per Share	Price Range High	Price Range Low
1992 by Quarter			
Fourth	$0.45	$37½	$34⅝
Third	0.45	36½	34⅛
Second	0.43	34⅝	32
First	0.43	35	31⅜
1991 by Quarter			
Fourth	$0.43	$35	$30⅛
Third	0.43	32½	27⅜
Second	0.41	29⅜	27¼
First	0.41	30¾	26¾

Item 6.

SELECTED FINANCIAL DATA

	1992	1991	1990	1989	1988
Condensed consolidated statements of income (thousands)					
Electric revenues (a)	$ 3,961,484	$ 3,816,960	$ 3,705,131	$3,692,955	$3,644,410
Electric expenses (a)	3,236,789	3,110,137	3,062,348	2,988,355	3,014,859
Electric operating income	724,695	706,823	642,783	704,600	629,551
Other income	85,007	150,905	146,740	101,826	46,211
Income before interest deductions	809,702	857,728	789,523	806,426	675,762
Interest deductions	301,619	274,105	251,335	234,815	227,631
Cumulative effect of accrual of unbilled revenues	—	—	—	—	102,255
Net income	508,083	583,623	538,188	571,611	550,386
Dividends on preferred and preference stock	56,407	54,683	52,616	52,477	53,329
Earnings for common stock	$ 451,676	$ 528,940	$ 485,572	$ 519,134	$ 497,057
Common stock data (b)					
Shares of common stock					
— year-end (thousands)	204,859	204,699	202,584	202,563	202,544
— average (thousands)	204,819	203,431	202,570	202,554	202,533
Per share of common stock					
Earnings (c)	$ 2.21	$ 2.60	$ 2.40	$ 2.56	$ 2.45
Dividends	$ 1.76	$ 1.68	$ 1.60	$ 1.52	$ 1.44
Book value — year-end	$ 20.26	$ 19.86	$ 18.84	$ 18.05	$ 17.01
Market price — high-low	$ 37 1/2-31 3/8	$ 35-26 3/4	$ 32 3/8-25 1/2	$ 28 1/4-21 3/8	$ 24 1/2-21 1/8
— year-end	$ 36 1/8	$ 35	$ 30 5/8	$ 28 1/16	$ 23 1/8
Balance sheet data (thousands)					
Total assets	$10,801,794	$10,470,615	$10,083,507	$9,542,398	$8,890,605
Long-term debt	$ 3,202,437	$ 3,159,575	$ 3,102,746	$2,822,442	$2,728,794
Preferred stock with sinking fund requirements	$ 279,519	$ 228,650	$ 239,800	$ 247,825	$ 255,850

(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.

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 one-time 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 compared to 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 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 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 impact of the Company's [illegible] of purchased power costs not currently collected in rates. 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 39.)

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

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 [illegible] 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 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 "double 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 redeem $229 million of preferred stock. As of December 31, 1992, the Company's bonds were rated "double 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 purchases to satisfy the requirements of the various stock purchase plans.

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 requirements for the stock split and for the conversion rights of preference stock.

The Company's embedded cost of long-term debt for 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 the return on purchased capacity levelization,

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 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 costs 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.)

Meeting Future Power Needs

The Company's strategy for meeting customers' 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.

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.

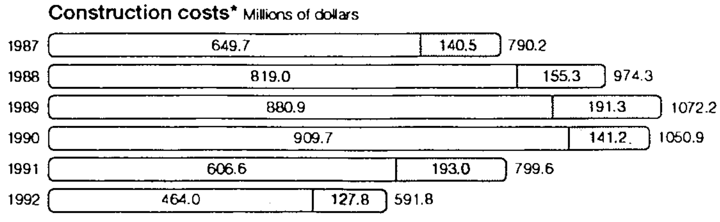
The purchase of capacity and energy is also an integral part of meeting future power needs. The Company currently has under contract 500 megawatts of capacity from other generators of electricity.

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.

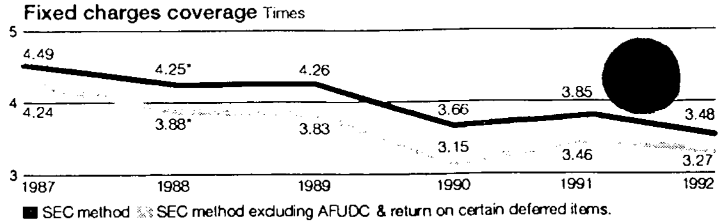
The Company has been engaged in a concentrated effort to

Construction costs* Millions of dollars



*Including AFUDC.

Fixed charges coverage Times



*Includes the cumulative effect of the accounting change for unbilled revenues.

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 [illegible]9,449 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 this 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 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 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 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.

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 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 $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 judgment 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

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, 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 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.

Item 8. ***Financial Statements and Supplementary Data.***

DUKE POWER COMPANY

INDEX

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	$3,705,131
Electric expenses			
Operation			
Fuel used in electric generation (Note 1)	**659,593**	657,725	660,298
Net interchange and purchased power (Notes 3 and 15)	**540,840**	545,840	565,034
Wages, benefits and materials	**636,729**	622,121	564,624
Maintenance of plant facilities	**403,162**	354,679	403,831
Depreciation and amortization (Notes 1 and 11)	**491,339**	431,624	405,762
General taxes	**215,493**	204,688	197,087
Income taxes (Notes 1 and 4)	**289,633**	293,460	265,712
Total electric expenses	**3,236,789**	3,110,137	3,062,348
Electric operating income	**724,695**	706,823	642,783
Other income (Notes 1, 4 and 14)			
Allowance for equity funds used during construction	**15,476**	50,704	79,176
Other, net	**83,216**	102,884	54,210
Income taxes — other, net	**(27,475)**	(25,472)	(15,284)
Income taxes — credit	**13,790**	22,789	28,638
Total other income	**85,007**	150,905	146,740
Income before interest deductions	**809,702**	857,728	789,523
Interest deductions			
Interest on long-term debt	**265,646**	274,662	260,333
Other interest	**41,736**	18,834	21,296
Allowance for borrowed funds used during construction (credit) (Note 1)	**(5,763)**	(19,391)	(30,294)
Total interest deductions	**301,619**	274,105	251,335
Net income	**508,083**	583,623	538,188
Dividends on preferred and preference stock	**56,407**	54,683	52,616
Earnings for common stock	**$ 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.

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	$ [illegible]88
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 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)	[illegible]28)
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)
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.

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 investments	367,217	286,793
Current assets		
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	67,302
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

	1992	1991
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
Notes 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)		
Total capitalization and liabilities	$10,801,794	$10,470,615

See Notes to Consolidated Financial Statements.

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
Retained Earnings			
Balance — Beginning of year	**$2,141,259**	$1,953,779	$[illegible]29
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	324,104
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.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Revenues

ues are recorded as service is rendered to customers. vables" 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 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 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 mber 1991, all coal-fired generating units are depreciated at f 2.57 percent and all nuclear units are depreciated at a rate .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 intercompany transactions have been eliminated in consolidation. (See "Subsidiary Highlights," page 38.)

F. Income Taxes

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.

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 J[illegible]7 assuring the legality of such adjustments in rates. In 1[illegible]he 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 $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 [illegible]2 percent on common equity authorized by the NCUC afte[illegible]tial 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.

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 NCE[illegible] 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 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 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 7½-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 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			
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

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 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 thousa[illegible]

	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.

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 b[illegible]or credit facilities, the Company maintained balances of $50[illegible]s 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
Amount 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	$285,500	$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%

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	$ —
[illegible]% C (Preferred Stock A)	1992	800,000	20,000	—
[illegible]% 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	—
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 fund 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 [illegible]1,500,000 in 1993 and $3,000,000 in 1994, 1995, 1996 and [illegible]7. Some additional redemptions are permitted at the Company's [illegible]ion. The Company reacquired 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 ½%	1992	$ —	$50,000
4 ¼% B	1992	—	50,000
6.06%-6.23%	1994	81,700	81,700
6.47%-6.60%	1995	40,300	40,300
4 ½%	1995	40,000	40,000
6.59%	1996	3,000	3,000
7 ⅞%	1996	100,000	100,000
7 ½% B	1997	—	100,000
5 ⅜%	1997	72,600	72,600
5 ⅝%	1997	100,000	—
6 ⅜%	1998	68,500	68,500
7%	1999	56,075	56,075
7.5%	1999	100,000	—
8% B	1999	—	64,739
6 ¼%	1999	65,000	—
7%	2000	100,000	—
7% B	2000	100,000	—
8 ½%	2000	—	69,244
8 ⅝% B	2000	—	95,635
7 ½%	2001	97,900	97,900
[illegible]% B	2001	38,050	38,050
[illegible]%	2002	78,100	78,100
[illegible]⅞% B	2002	67,900	67,900
7 ¾%	2003	94,872	94,872
8 ⅛% B	2003	—	98,050
8%	2004	75,000	—
(continued)			
9 ¾%	2004	$ —	$ 95,623
7.37%-7.41%	2004	100,000	—
7%	2005	200,000	—
9 ½%	2005	—	92,800
8 ⅜%	2006	—	96,850
8 ⅛%	2007	119,500	119,500
9 ⅜%	2008	—	120,610
10 ⅛% B	2015	—	50,000
9%	2016	175,000	175,000
8 ½%	2017	150,000	150,000
9 ⅝%	2020	200,000	200,000
10 ⅛% B	2020	150,000	150,000
8 ¾%	2021	150,000	150,000
8 ⅜% B	2021	150,000	150,000
8 ⅝%	2022	100,000	—
8.95%	2027	15,925	15,994
Pollution-Control			
9 ⅛%	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.

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 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 [illegible]mon 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, 6¾% Convertible Series AA at 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	$ 3[illegible]
5.72% D	1966	350,000	35,000	3[illegible]
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
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
Preference Stock	100	1,500,000	1,500,000

(continued from page 32)

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.

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.

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 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.

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		$[illegible]259
Interest cost on projected benefit obligation		85,613		79,175		[illegible]73
Actual return on plan assets	(50,897)		(127,978)		(33,506)	
Amount deferred for recognition	(32,277)		52,574		(41,241)	
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 investments and cash equivalents, common stocks, real estate investments 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 age. For 1990, an increase of 6.5 per[illegible]as assumed for all participants. The expected long-term rate [illegible]n on plan assets used in determining pension cost was 9.25 percent in 1992 and 1991 and 10.0 percent in 1990.

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 at 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 retirees must have at least ten years of service to 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 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 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 as 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 $11,900,000 and $10,200,000, respectively.

(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)
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 investments and cash equivalents, common stocks, real estate investments 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 Lives 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 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 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 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 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 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 $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 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 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 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 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.

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 Statements of Income. The income is primarily from dividends and interest on securities. The taxes associated 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 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.

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 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 our 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.

Charlotte, North Carolina
February 15, 1993

DELOITTE & TOUCHE
Certified Public Accountants

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 L. HAUSER
Controller

SELECTED FINANCIAL DATA

Quarterly Financial Data

Dollars in Thousands (except per-share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
1992 by quarter					
Electric Revenues	$981,330	$899,319	$1,139,525	$941,310	$3,961[illegible]
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
Earnings Per Share	$0.45	$0.36	$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 1990. (a) (b) Highlights of selected subsidiaries are presented below.

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. (dollars in thousands)

	1992	1991	1990
Assets net of liabilities	$ 42,910	$ 39,384	$[illegible]
Net income	$ 3,526	$ 2,721	$[illegible]
Number of employees (c)	191	194	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. (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	[illegible]
Assets net of liabilities	$ 36,687	$ 13,480	$3[illegible]
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 non-utility operations includes elimination of intercompany profit of $1,211,000, after tax.
(c) Full-time employees.

DUKE POWER COMPANY

SCHEDULE V — PROPERTY, PLANT AND EQUIPMENT

(Dollars in thousands)

Description	Balance Beginning of Year	Additions	Retirements	Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1992					
Electric Plant in Service — At Original Cost					
Production	$ 6,228,232	$ 121,364	$ 2,521	$ 60,086	$ 6,407,161
Transmission	1,300,021	34,235	2,114	(474)	1,331,668
Distribution	3,335,893	236,777	53,227	(208)	3,519,235
General	894,685	53,114	25,046	(51,042)	871,711
Miscellaneous	71,380	221	174	(7,314)	64,113
Nuclear Fuel	2,004,441	264,506	—	—	2,268,947
Total electric plant in service	13,834,652	710,217	83,082	1,048	14,462,835
Construction Work in Progress	501,942	(11,534)	—	—	490,408
Other Property — At Cost					
Water plant	35,009	830	227	43	35,655
Transit plant	1,499	—	1,499	—	—
Total other property	36,508	830	1,726	43	35,655
Total plant	$14,373,102	$ 699,513	$ 84,808	$ 1,091	$14,988,898
For the Year Ended December 31, 1991					
Electric Plant in Service — At Original Cost					
Production	$ 4,965,205	$ 1,229,905	$ 7,356	$ 40,478	$ 6,228,232
Transmission	1,223,152	80,809	2,627	(1,313)	1,300,021
Distribution	3,079,886	283,097	27,681	591	3,335,893
General	844,706	98,575	47,163	(1,433)	894,685
Miscellaneous	111,972	(2,229)	201	(38,162)	71,380
Nuclear Fuel	1,870,975	133,466	—	—	2,004,441
Total electric plant in service	12,095,896	1,823,623	85,028	161	13,834,652
Construction Work in Progress	1,521,391	(1,019,449)	—	—	501,942
Other Property — At Cost					
Water plant	33,886	1,312	189	—	35,009
Transit plant	2,782	—	1,283	—	1,499
Total other property	36,668	1,312	1,472	—	36,508
Total plant	$13,653,955	$ 805,486	$ 86,500	$ 161	$14,373,102
For the Year Ended December 31, 1990					
Electric Plant in Service — At Original Cost					
Production	$ 4,880,284	$ 117,684	$ 63,285	$ 30,522	$ 4,965,205
Transmission	1,152,588	76,324	4,830	(930)	1,223,152
Distribution	2,773,018	334,983	29,158	1,043	3,079,886
General	788,160	73,985	25,012	7,573	844,706
Miscellaneous	144,933	3,862	—	(36,823)	111,972
Nuclear Fuel	1,694,967	176,008	—	—	1,870,975
Total electric plant in service	11,433,950	782,846	122,285	1,385	12,095,896
Construction Work in Progress	1,255,232	266,159	—	—	1,521,391
Other Property — At Cost					
Water plant	33,006	926	51	5	33,886
Transit plant	2,824	—	42	—	2,782
Total other property	35,830	926	93	5	36,668
Total plant	$12,725,012	$ 1,049,931	$122,378	$ 1,390	$13,653,955

DUKE POWER COMPANY

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

(Dollars in thousands)

Description	Beginning of Year	Depreciation	Clearing and Other Accounts	Retirements	Other Changes Add (Deduct)	Balance End of Year
For the Year Ended December 31, 1992						
Accumulated Depreciation of						
Electric Plant						
Production	$2,119,391	$226,137	$ —	$ 11,572	$ (5,637)	$2,328,319
Transmission	531,332	33,213	—	3,208	(269)	561,068
Distribution	979,805	122,311	—	49,127	419	1,053,408
General	229,400	26,612	4,758	18,929	853	242,694
Miscellaneous	49,850	—	357	—	(44,670)	5,537
	3,909,778	408,273	5,115	82,836	(49,304)	4,191,026
Accumulated Amortization of Limited Term Plant	5,983	—	687	4	(187)	6,479
Accumulated Amortization of Nuclear Fuel	1,722,192	—	151,638	—	—	1,873,830
	5,637,953	408,273	157,440	82,840	(49,491)	6,071,335
Accumulated Depreciation of Water Plant	8,094	691	—	221	21	8,585
Accumulated Depreciation of Transit Plant	1,420	2	—	1,449	27	—
Total Accumulated Depreciation	$5,647,467	$408,966	$157,440	$ 84,510	$(49,443)	$6,079,920
For the Year Ended December 31, 1991						
Accumulated Depreciation of						
Electric Plant						
Production	$1,902,284	$198,372	$ —	$ 13,054	$ 31,789	$2,119,391
Transmission	500,555	34,589	—	2,901	(911)	531,332
Distribution	896,226	109,461	—	26,787	905	979,805
General	221,691	30,920	13,393	35,269	(1,335)	229,400
Miscellaneous	88,258	—	352	—	(38,760)	49,850
	3,609,014	373,342	13,745	78,011	(8,312)	3,909,778
Accumulated Amortization of Limited Term Plant	5,108	—	497	—	378	5,983
Accumulated Amortization of Nuclear Fuel	1,552,977	—	169,215	—	—	1,722,192
	5,167,099	373,342	183,457	78,011	(7,934)	5,637,953
Accumulated Depreciation of Water Plant	7,578	682	—	166	—	8,094
Accumulated Depreciation of Transit Plant	2,662	41	—	1,283	—	1,420
Total Accumulated Depreciation	$5,177,339	$374,065	$183,457	$ 79,460	$ (7,934)	$5,647,467
For the Year Ended December 31, 1990						
Accumulated Depreciation of						
Electric Plant						
Production	$1,753,706	$181,151	$ —	$ 69,913	$ 37,340	$1,902,284
Transmission	471,754	33,655	—	5,597	743	500,555
Distribution	826,188	98,993	—	28,154	(801)	896,226
General	193,387	30,839	15,324	17,484	(375)	221,691
Miscellaneous	124,792	—	349	—	(36,883)	88,258
	3,369,827	344,638	15,673	121,148	24	3,609,014
Accumulated Amortization of Limited Term Plant	4,585	—	522	(1)	—	5,108
Accumulated Amortization of Nuclear Fuel	1,397,475	—	155,502	—	—	1,552,977
	4,771,887	344,638	171,697	121,147	24	5,167,099
Accumulated Depreciation of Water Plant	6,967	657	—	46	—	7,578
Accumulated Depreciation of Transit Plant	2,602	102	—	42	—	2,662
Total Accumulated Depreciation	$4,781,456	$345,397	$171,697	$121,235	$ 24	$5,177,339

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, 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

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, 6¾% 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, 6¾% Convertible Series AA, $100 par, 500,000 shares authorized (no shares outstanding as of December 31, 1992) (3)	—	169	184
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, 6¾% Convertible Series AA, into shares of common stock was $11.95.

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" and "Information Regarding the Board of Directors" in the proxy statement of the Company relating to its 1993 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 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 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 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, 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, 1992
  - Consolidated Statements of Cash Flows for the Three Years Ended December 31, 1992
  - Consolidated Balance Sheets — December 31, 1992 and 1991
  - Consolidated Statements of Capitalization — December 31, 1992 and 1991
  - Consolidated Statements of Retained Earnings for the Three Years Ended December 31, 1992
  - Notes to Consolidated Financial Statements
- Supplemental Financial Data (Unaudited)
- Supplemental Schedules
  - Schedule V — Property, Plant 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)

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.

Exhibits

(a) — See Exhibit Index on page 46.

Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1992.

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

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.

DUKE POWER COMPANY
(Registrant)

By: 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.

Signature	Title	Date
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 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 and Exchange Commission as an exhibit hereto.

/s/ LEWIS F. CAMP, JR.
Lewis F. Camp, Jr., 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 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. 1-4928, as Exhibit 3-D).
3-E	— Articles of Amendment to the Articles of Incorporation 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, 1992 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 Stock 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 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 7% 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).

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 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).

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 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. 2-28023, 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).

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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).
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).

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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.
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 for 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†	— Employees' Stock Ownership Plan.
*10-F†	— Employee Incentive Plan.
*10-G†	— 1992 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.

Exhibit Number	
*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.
*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.

† Compensatory plan or arrangement required to be filed as an exhibit.

EXHIBIT 12

DUKE POWER COMPANY

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(Dollars in Thousands)

	Year Ended December 31				
	1992	**1991**	**1990**	**1989**	**1988**
Earnings Before Income Taxes (1)	$ 811,401	$ 879,766	$ 790,546	$ 867,641	$ 827,732
Fixed Charges	327,308	308,862	297,116	266,497	254,622
Total	$1,138,709	$1,188,628	$1,087,662	$1,134,138	$1,082,354
Fixed Charges					
Interest on long-term debt	$ 257,149	$ 269,419	$ 255,334	$ 232,510	$ 230,403
Other interest	47,972	22,780	24,306	18,203	7,979
Amortization of debt discount, premium, and expense	8,497	5,242	4,998	4,677	4,658
Interest component of rentals	13,690	11,421	12,478	11,107	11,582
Fixed Charges	$ 327,308	$ 308,862	$ 297,116	$ 266,497	$ 254,622
Ratio of Earnings to Fixed Charges	3.48	3.85	3.66	4.26	4.25

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

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