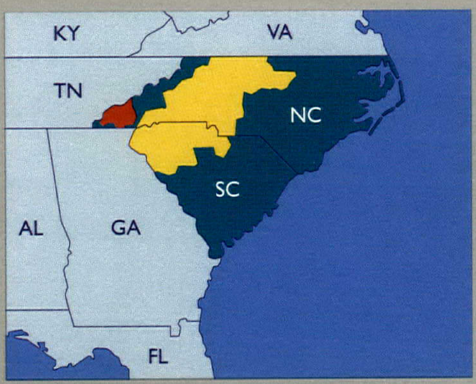
DUKE POWER COMPANY 1993 ANNUAL REPORT

ABOUT THE COVER Throughout Duke Power, quality improvement teams are performing important work designed to improve the way teammates do their jobs. The team shown on this year's cover developed new safety equipment and procedures to make climbing jobs throughout the Company safer, with the ultimate goal of reaching 100 percent fall protection. A story on the team's work is on page 18.



Nantahala Power and Light Company
Duke Power Company

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. Founded 89 years ago, the Company is the nation's sixth-largest investor-owned electric utility as measured by kilowatt-hour sales.

Duke Power operates three nuclear generating stations, eight coal-fired stations and 27 hydroelectric stations. Together, these units produced 84 billion kilowatt-hours of electricity in 1993. Total electric revenues reached $4.3 billion, with approximately 70 percent of sales in North Carolina and 30 percent in South Carolina.

Principal subsidiaries and other diversified activities of the Company include:

CHURCH STREET CAPITAL CORP.
Funds management and parent company of non-regulated subsidiaries

CRESCENT RESOURCES, INC.
Real estate development and forest management

DUKE ENERGY GROUP
Development and management of investments in electric power facilities

DUKE ENGINEERING & SERVICES, INC.
Engineering and consulting services

DUKE/FLUOR DANIEL
Engineering and construction services

DUKE MERCHANDISING
Appliance and electronics sales and service

WATER OPERATIONS
Water service for over 15,000 South Carolina and more than 4,000 North Carolina customers

NANTAHALA POWER AND LIGHT COMPANY
Electric utility serving more than 50,000 customers in a five-county area in western North Carolina

FINANCIAL HIGHLIGHTS

	1993	1992	Percent increase (decrease)
Kilowatt-hour sales (millions)	76,058	71,042	7.1
Electric revenues	$4,281,876,000	$3,961,484,000	8.1
Earnings for common stock	$ 573,986,000	$ 451,676,000	27.1
Common stock data			
Average shares outstanding	204,859,000	204,819,000	—
Earnings per share	$2.80	$2.21	26.7
Dividends per share	$1.84	$1.76	4.5
Book value per share (year-end)	$21.17	$20.26	4.5
Return on average common equity	13.6%	11.1%	22.5
Plant construction costs (including AFUDC)	$ 547,612,000	$ 463,971,000	18.0
Nuclear fuel construction costs (including AFUDC)	$ 121,848,000	$ 127,855,000	(4.7)
Internal cash generation (including refinancings)	46%	50%	(8.0)
Internal cash generation (excluding refinancings)	112%	101%	10.9
Earnings coverage of fixed charges, SEC method	4.68X	3.48X	34.5
Total electric plant, net	$8,924,109,000	$8,780,123,000	1.6
Peak load (KW) (a)			
Summer	15,720,000	14,763,000	6.5
Winter	13,314,000	13,001,000	2.4
Full-time employees at year-end (b)	18,274	18,727	(2.4)

(a) The Company's all-time peak of 15,720 megawatts (MW) on July 29, 1993, was surpassed on January 19, 1994, by a new all-time peak of 16,070 MW.

(b) Includes 789 and 759 full-time employees of subsidiaries and affiliates for 1993 and 1992, respectively.

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For Duke Power, 1993 proved to be a good year indeed. Earnings increased to $2.80 per share on total revenues of $4.3 billion. We experienced a 7.1 percent increase in sales thanks to weather-related factors and continued economic growth in our service territory. Earnings for 1993 also rebounded from a customer refund that caused a 32-cent charge against earnings in 1992.

Bill Grigg Named Chairman-elect In January, your Board of Directors named Bill Grigg to be the next Chairman, President and Chief Executive Officer of Duke Power Company, effective at the annual meeting on April 28, 1994. Bill's selection is cause for great personal satisfaction for me; I am confident he is the leader we need to take the Company to a new level in the rapidly changing utility environment.

In making its decision, the Board recognized Bill's leadership, vision, competitiveness and caring. As Vice Chairman, Bill is responsible for setting policy and direction for the Company's Corporate Group departments. A graduate of Duke University Law School, Bill joined the Company in 1963 as assistant general counsel. He was first elected to the Board of Directors in 1972. Over the years he performed in a variety of roles, culminating in his selection as Chairman at the Board's January meeting.

Bill is only the latest in a long line of executives whose careers have been nurtured through Duke Power's leadership development program. Our goal is to ensure a succession of capable leaders who can anticipate change, prepare the Company to meet any challenges and further the process of continuous improvement.

Creating A More Competitive Company It has been my privilege to be part of the Duke Power team since 1955 and to serve as the Company's Chairman for the last 12 years. Throughout my career I have found my work to be on the cutting edge of challenge — and fun, too. In April, following the Company's annual meeting, I will step down as Chairman, President and Chief Executive Officer and serve as a consultant until my official retirement in June.

In the dozen years since I became Chairman, your Company has enjoyed many successes. We have more than doubled annual revenues to $4.3 billion in 1993 from $1.9 billion in 1981. Net income increased to $626 million from $336 million in 1981. Earnings per share have grown to $2.80 per share in 1993 from $1.58 in 1981. I am proud of my teammates' efforts to mold Duke Power into a leaner, more responsive company that can more ably meet the competitive demands of the marketplace — today and tomorrow.

The traditional competition nationally between electric utilities and natural gas providers continues to grow. In our own service area, the competition between public utilities and cooperative and municipal electric distributors remains intense. Neighboring utilities are working just as hard as we are to promote economic development within their service territories.

While we continue to deal with these traditional competitive forces, our customers are now asking us to help them compete more effectively. Duke Power is responding by offering time-of-use pricing and promoting innovative applications of electricity in industrial processes. Through a subsidiary, we have also entered the highly competitive world of independent power production.

Developing markets outside our traditional franchise is one way Duke is responding to slowing growth in kilowatt-hour sales. Since 1986, kilowatt-hour sales industry-wide have grown at less than half the rate experienced in the 1970s and early 1980s. This has clear implications for the industry, the most significant being diminished growth in returns to shareholders. If we are to continue growth in shareholder value, we must develop new revenue sources. Building on our traditional strengths in power production is part of the answer.


William H. Grigg
William S. Lee

Technology is another challenge for our industry. Photovoltaics, fuel cells, efficient storage batteries and more efficient transmission and distribution are examples of technological improvements that present new opportunities for companies in our industry. As these and other technological innovations give customers more options, the winning utilities will be those that capitalize on these improvements to enhance their business.

Finally, increasing concern over environmental quality affects all utilities. Complying with the Clean Air Act, relicensing our hydroelectric facilities and extending the licenses for our nuclear power plants are important issues. All of these matters can significantly affect our ability to compete. Our goal is to balance competitive needs and environmental stewardship, so that we meet the expectations of our customers while preserving the quality of our environment. Emerging environmental issues also have the potential to affect the electric utility industry. For example, concern over electromagnetic fields (EMF) has received increasing attention. Duke supports and funds EMF research, and we are committed to understanding the scientific facts regarding EMF. We will continue to be an industry leader in communicating with customers about this and other environmental issues.

Duke Teammates Are Embracing Excellence We still have many challenges ahead of us, but Duke Power is a far different company than it was 12 years ago or even five years ago. In 1990, the Company committed itself to meeting customer expectations through total quality, what we call managing for excellence. When we began this process, we understood it represented a long-term commitment to continuously improving the way we perform. It meant changing the way we had done things in the past and overturning traditional paradigms. To some, the changes may have seemed to challenge the core values on which Duke Power was built.

The last four years have not been easy. Tough decisions have been made at all levels of the Company. Initially, resistance to change was evident, but as we have persevered and developed our total quality management skills, teammates' understanding of the relationship between total quality and success in the marketplace has become clearer. The connection between a teammate's performance and his or her financial and professional success is clearer. We have come to understand that job security comes only from our customers.

Ultimately, managing for excellence is teaching us that change is the only constant and that its pace will continue to accelerate. We are learning that the best way to manage change is to embrace it and make it part of our daily routine.

During 1993, Bill Grigg and I had the opportunity to meet in small groups with more than 1,000 of our teammates from throughout the Company. We are pleased that their enthusiasm for the excellence process is growing. Excellence has unleashed the power of individual initiative, and the result is improved responsiveness to customers, reduced red tape, improved work processes and cost savings throughout the Company.

Yet, even as we improve our performance, we are discovering still more opportunities. Later in this report, you will see examples of how teams, given the freedom to seek creative solutions, have responded with innovations. These are symbolic of changes occurring throughout the Company. I salute our teammates' responsiveness to the quest for excellence and their courage to change.

Sincerely,

William S. Lee

William S. Lee
Chairman of the Board, President and Chief Executive Officer
February 11, 1994

1993 Sales - KWH	
Residential	+9.4%
General service	+6.9%
Textile	+2.3%
Non-textile industrial	+5.8%
Total industrial	+4.3%
All other	+10.6%
Total	+7.1%

A YEAR OF SOLID PERFORMANCE Colder winter and hotter summer weather in 1993 was the principal factor that increased Duke Power's earnings per share by 27 percent over 1992 to $2.80 per share on revenues of $4.3 billion. Total kilowatt-hour sales increased to 76.1 billion from 71.0 billion in 1992. Kilowatt-hour sales to residential customers rose 9.4 percent in 1993. Sales to textile customers increased 2.3 percent, while sales to other industrial customers as a group grew by 5.8 percent. General service sales posted a 6.9 percent increase over 1992.

Earnings in 1993 also rebounded from the effect of a one-time charge of 32 cents per share in 1992 for a $95 million refund to customers. The refund was required after the North Carolina Utilities Commission reduced the Company's authorized rate of return for the five-year period that ended in November 1991.

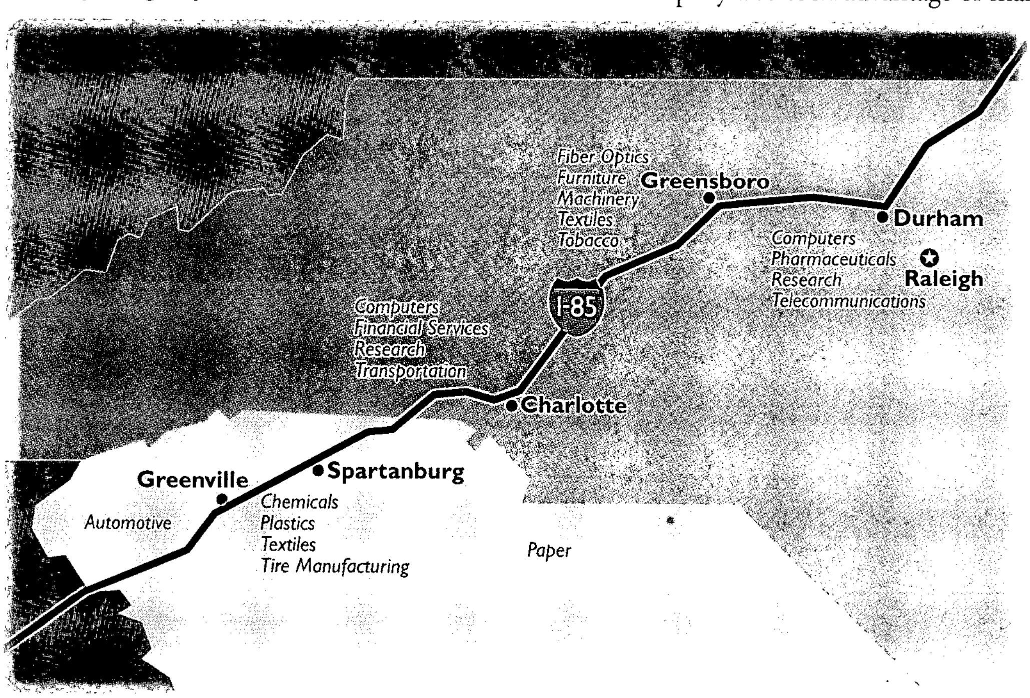
Reductions in expenses at the Company's nuclear and fossil stations were more than offset by other expenses during 1993.

The Company raised its quarterly dividend two cents per share in 1993, marking the 18th straight year the Board of Directors authorized an increase. The Company's policy is to increase dividends per share at a rate greater than inflation, while maintaining a long-term dividend payout ratio of no more than 65 percent of earnings. Over the last five years, the annual growth rate for dividends has been 5.0 percent, while inflation has averaged 3.9 percent. The average dividend payout ratio for the same period is 67 percent. Duke's indicated annual dividend is $1.88 per share.

Consistent growth in the Company's dividend depends on growth in earnings. To support such growth and to strengthen its competitive position, Duke Power has a long-term objective of controlling costs and increasing contributions from diversified businesses. As part of cost control, the Company continues to redesign its business practices with the goal of using resources more efficiently and effectively. These efforts enable the Company to support a growing customer base with fewer full-time employees. The number of full-time employees declined from 18,727 at year-end 1992 to 18,274 at the end of 1993.

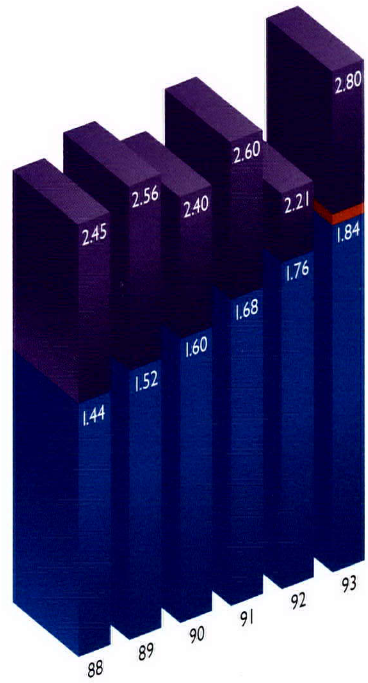
The Company also took advantage of sharply lower interest rates in 1993 to refinance a total of $1.6 billion in outstanding securities. By issuing debt at lower rates, the Company reduced its embedded cost of debt to 8.01 percent at the end of 1993 from 8.39 percent at the end of 1992. Lower interest rates also allowed the Company to issue preferred stock with lower dividend rates. These new issues of preferred stock reduced the embedded cost of preferred stock to 6.76 percent at year-end 1993 from 7.05 percent at the end of 1992.

The I-85 corridor, which runs through the heart of Duke Power's service territory, has attracted attention for industry along its path.



1993 Performance at a Glance

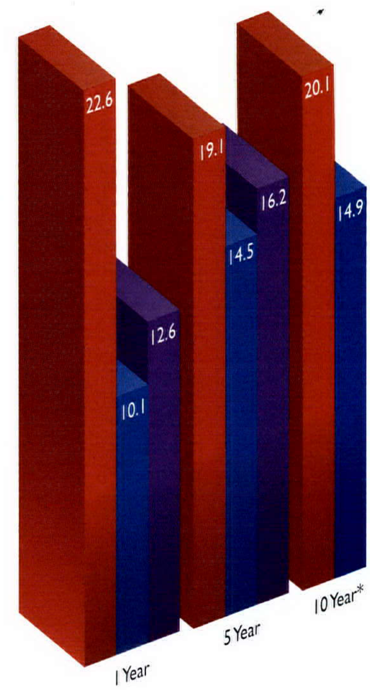
Earnings per share* Dollars



■ Earnings per share
■ Indicated dividend rate of $1.88
■ Dividends per share

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

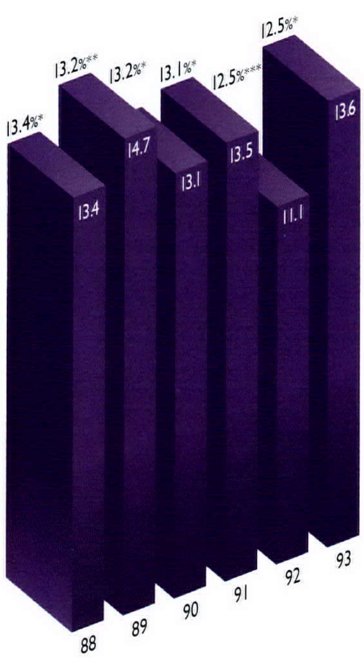
Annual total return to shareholders Percent



■ Duke ■ S&P 500 ■ S&P Electric

* *10 Year S&P Electric data not available.*

Return on average common equity Percent

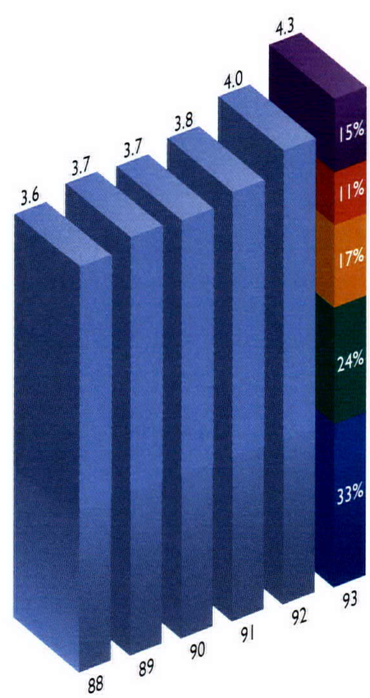


* *Average authorized return (NC jurisdiction)*

** *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.*

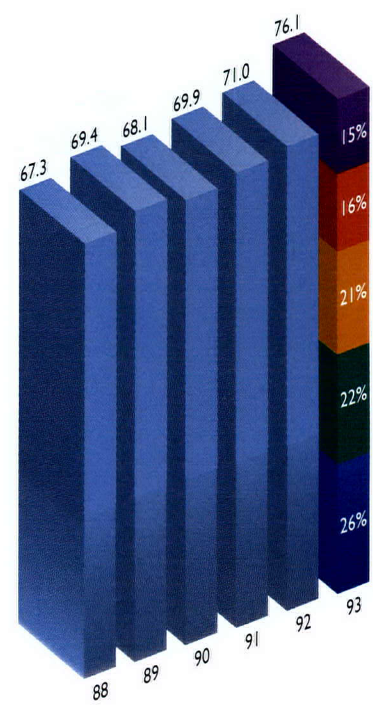
Electric revenues* Billions of dollars



■ Residential ■ Industrial-textile
■ General service ■ Wholesale/other
■ Industrial-other

* *From 1988 to 1990, restated to reflect reclassification of certain power transactions previously classified as net interchange and purchased power, prior to a 1990 FERC order.*

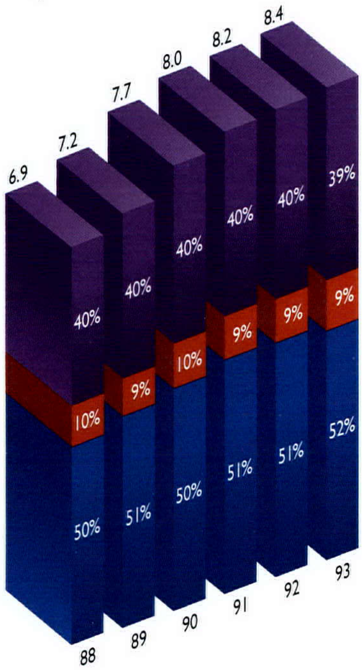
Kilowatt-hour sales* Billions



■ Residential ■ Industrial-textile
■ General service ■ Wholesale/other
■ Industrial-other

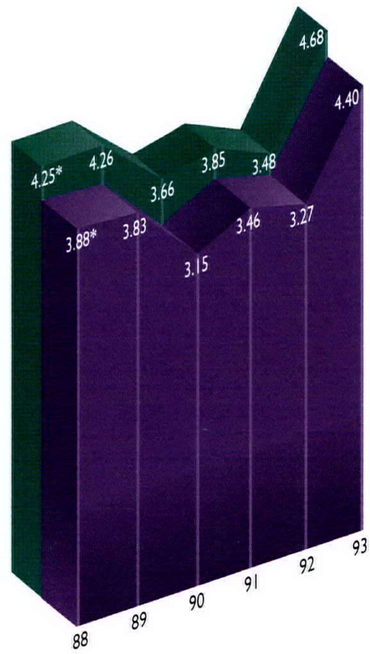
* *From 1988 to 1990, restated to reflect reclassification of certain power transactions previously classified as net interchange and purchased power, prior to a 1990 FERC order.*

Capital structure
(Excludes current maturities)
Billions of dollars



■ Long-term debt
■ Preferred & preference stock
■ Common equity

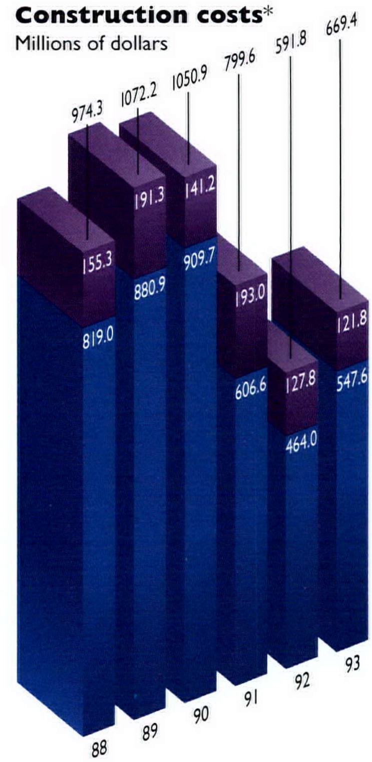
Fixed charges coverage
Times



■ SEC method
■ SEC method excluding AFUDC & return on certain deferred items.

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

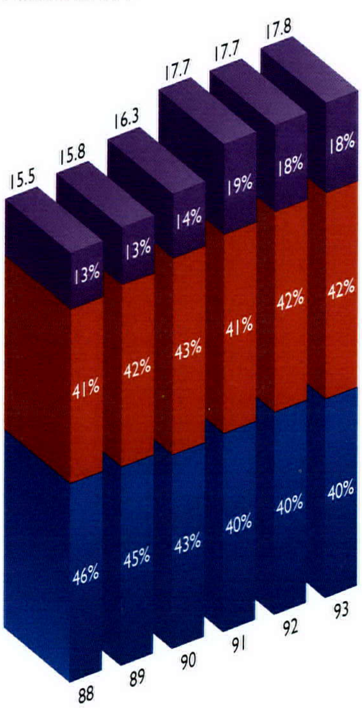
Construction costs*
Millions of dollars



■ Nuclear fuel

* *Including AFUDC.*

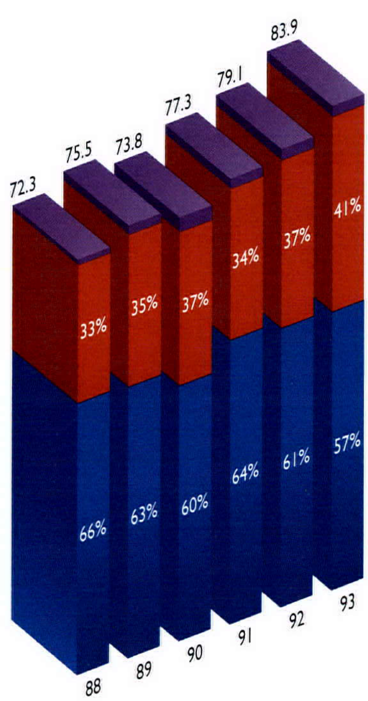
Generating capacity
Millions of KW



■ Hydro & other
■ Coal
■ Nuclear*

* *Includes 100% of Catawba generation.*

Net generation*
Billions of KWH

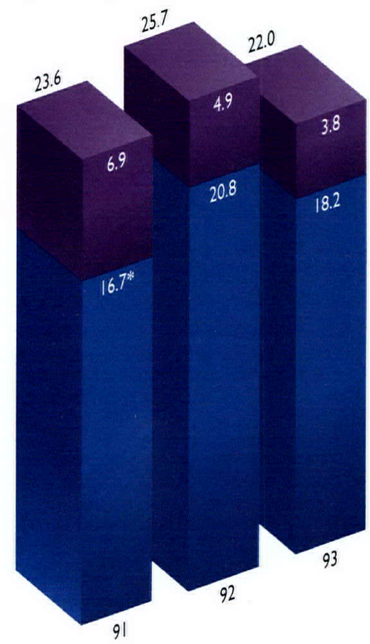


■ Hydro & other
■ Coal
■ Nuclear**

* *Excludes interchange power with the other joint owners of the Catawba Nuclear Station.*

** *Includes 100% of Catawba generation.*

Subsidiary and diversified earnings
(From investments and diversified operations) Millions of dollars



■ Investment Income
■ Diversified Operations

* *Excludes the cumulative effect of an accounting change of $6.7 after tax.*

DIVERSIFICATION TO BUILD VALUE Duke affiliates and subsidiaries are part of the Company's strategy to enhance shareholder value as the core electric business matures. Participation in these ventures offers the Company a chance to pursue opportunities to create value outside the regulated utility business. As part of its diversification strategy, Duke Power has elected to compete in commercial ventures closely aligned with Duke's core business.

Duke Engineering & Services, Inc. (DE&S) offers engineering, construction management, start-up and operating support, quality assurance and technical services for the hydroelectric, oil, gas-fired and nuclear power industries. Duke/Fluor Daniel, a joint venture with Fluor Daniel, Inc., provides similar services for coal-fired systems and also offers construction services.

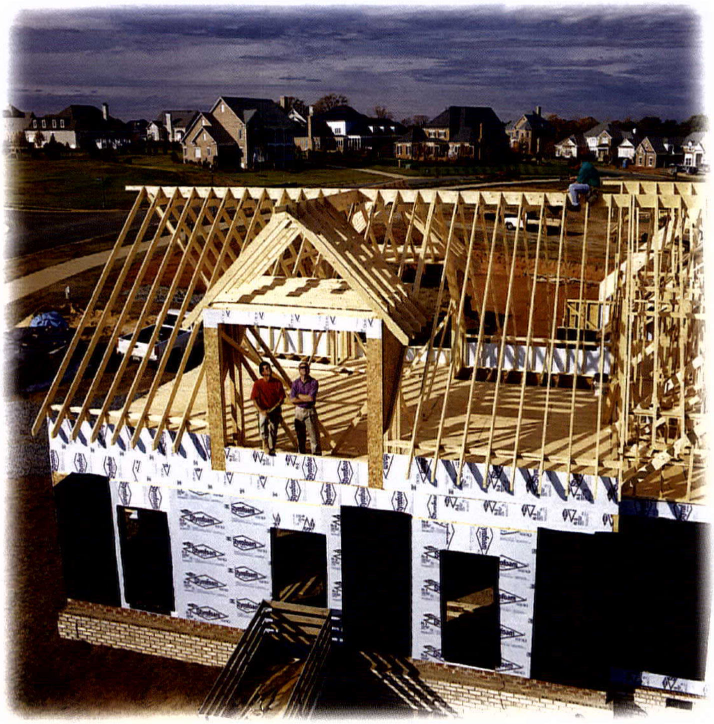
Duke Energy Group primarily develops and manages investments in electric power facilities in the domestic market and abroad. Crescent Resources, Inc. is a real estate development and forest management company created to utilize Duke Power's real estate holdings.

These companies, together with Nantahala Power and Light Company, a wholly owned electric utility serving five counties in western North Carolina, Church Street Capital Corp., Duke Power's non-utility investment arm and other non-electric businesses, contributed $22 million after taxes to corporate earnings in 1993, down 15 percent from 1992.

Duke's subsidiaries and affiliates are further extending experience and expertise originally developed within the parent company. For example, Duke Energy Group is participating in three projects in Latin America and is exploring additional opportunities in Latin America, the Pacific Rim and the United States. DE&S's power plant expertise positions it to compete for new business in the power industry both domestically and internationally. DE&S also serves a wide range of non-utility and government clients. Duke/Fluor Daniel combines the design-and-build expertise of Duke Power and Fluor Daniel to provide engineering and construction services to utilities and independent power producers adding coal-fired generating capacity.

In the years ahead, the Company expects the contributions from these subsidiaries and affiliates to grow.

Crescent Resources develops high-quality residential communities like The Peninsula, built on the shores of Lake Norman.



OUR PRODUCT IS SERVICE At Duke Power, it has never been more apparent that customer service is our most important product. During 1993, the Company added services and capabilities designed to expand customers' access to Duke Power and better meet their particular needs.

For example, early in the year, the Company consolidated its telephone customer service and dispatching services. As a result, any customer can contact a Company representative 24 hours a day, seven days a week. Computer technology gives customers the option of obtaining account information automatically with a touch-tone phone, reporting a power outage or talking with a representative. When exceptionally heavy call volume results in customers waiting, the system provides updates on their

approximate waiting time. This gives customers the option to remain on line, call back or choose automated services.

Duke's determination to meet customer needs is also reflected in various pricing options designed to give customers more control over their cost of electricity. During 1993, regulatory commissions in both North Carolina and South Carolina approved a pilot hourly pricing rate for industrial customers. Under this program, Duke varies its hourly energy prices to the customer based on the impacts of projected weather, plant availability and overall demand on the Duke system. As a result, customers can control their energy costs by shifting production to periods when the cost of electricity is lower. Residential customers can also choose a rate which sets the price per kilowatt-hour based on the time of day.

Before it can be certified as a Maximum Value Home, an all-electric home in the Duke Power service territory undergoes rigorous testing. Space conditioning ductwork gets close scrutiny to ensure that the home's high-efficiency heat pump blows cool air in the summer and hot in winter.

In South Carolina, the Public Service Commission approved an industrial diversity rate, which is designed to promote variety in Duke's industrial base. The rate is available for up to four years to new manufacturers who can be served directly from Duke's transmission system and meet certain other requirements.

The Company also established an electric vehicle rate to create a framework for recharging electrically powered vehicles. At present, the rate is part of a pilot project for evaluating customer acceptance, metering equipment and pricing components.

Hourly pricing and innovative rates for industrial customers are ways Duke Power believes it can contribute to economic growth within the service area. In return, Duke benefits through improved system utilization, growth in kilowatt-hour sales and diversification of its industrial customer base. While textile manufacturers accounted for more than 40 percent of kilowatt-hours sold to industry in 1993, Duke's industrial customers also include manufacturers of machinery and equipment (13 percent of industrial kilowatt-hours sold), chemical and chemical-related manufacturers (9 percent), producers of paper and allied products (7 percent) and rubber and plastic producers (8 percent).

Duke's belief that industrial diversification enhances the region's economy and the stability of the Company's revenue base is the basis for the Company's vigorous support of industrial recruiting to win customers such as the BMW manufacturing plant under construction near Greer, S.C. The Company also actively participated in the successful effort to win a National Football League franchise for the Carolinas, in the belief that the team will add to the quality of life in the region and serve as a positive factor in keeping and attracting business and industry.

Duke Power and Monsanto – Partnership Pays Off

Monsanto's nylon production plant depends on clean, dependable electricity to power its manufacturing processes. The work of a Duke Power quality improvement team resulted in Monsanto's recognition of Duke as a preferred supplier.

The Team

Mike Cullen
Bill Fox
Rick Henderson
Larry Palmer
Chris Rolfe
Steve West
Steven Whisenant

Can a supplier really have a partnership with a customer? The relationship that Duke Power and Monsanto Company created at Monsanto's nylon production plant in Greenwood, S.C., shows a partnership can not only exist, but also thrive to the benefit of both supplier and customer.

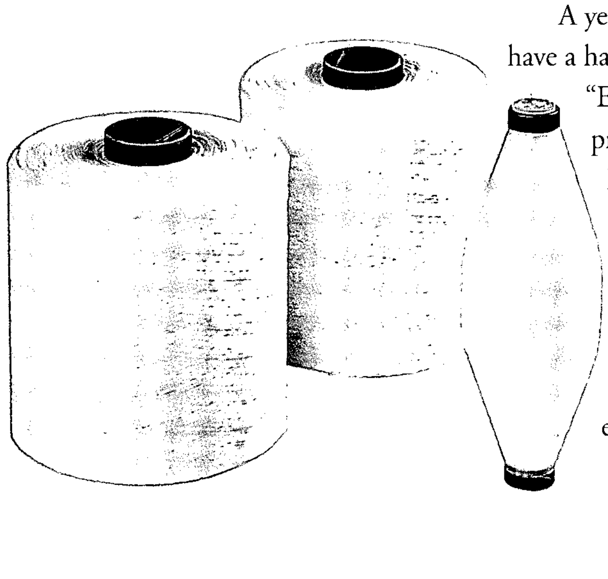
In the summer of 1992, Monsanto asked Duke to participate in its Vendor Rating System survey, an outgrowth of Monsanto's own commitment to Total Quality Management. Monsanto buys products and services from more than 60,000 vendors all over the world and rates vendors to ensure consistent, quality-oriented service. However, it had never rated utilities. Duke was the first, according to Steve West, a power delivery engineer in Duke's Greenwood office.

With West as the primary liaison between the companies, Duke created a team to respond to the quality survey. Besides West, the team included Industrial Marketing Manager Bill Fox, Corporate Performance Vice President Chris Rolfe, Mike Cullen of the Customer Group Re-engineering team, Marketing Manager Rick Henderson and Power Delivery Engineer Steven Whisenant. Working with Monsanto representatives, the team measured Duke's quality processes, service reliability quality, communications and customer service quality and quality cost management systems. In September 1992, Duke learned it had scored 91.5 out of a possible 100 points. Even so, the assessment highlighted areas needing improvement that Duke teams addressed one by one. Then an unexpected power outage put the partnership to the test.

Producing nylon depends on having reliable, high-quality electricity. The Greenwood plant runs 24 hours a day, seven days a week. Even a momentary outage can halt production for days or weeks at a time, because production machinery must be torn down and cleaned after an outage. So, when a relay on a Duke transformer failed, "it cost them a bundle," West said.

As a result of the outage, Duke put together another team that included Greenwood Area Power Delivery Supervisor Larry Palmer and others in Palmer's department to discover the cause. An inspection turned up a design flaw in the relay. Duke engineers began working with the relay manufacturer to correct the flaw. The partnership between Duke and Monsanto opened up communication channels. "Before we might have been hesitant to share information with each other," West said. "Now, we have a much closer relationship. It's more like we're all one team now."

A year and a half after Monsanto's initial survey, all Duke Power teammates who have a hand in directly serving Monsanto have toured the Greenwood plant. "Everyone knows the importance of quality power," West said. Duke is still a preferred supplier, and the Company is committed to achieving Monsanto's highest recognition as a certified supplier during 1994. During a barbecue Monsanto hosted honoring the Duke team, Monsanto's Charlie Rogers, the Greenwood team leader, perhaps gave Duke Power the best compliment it could have received. "The best thing I can say about Duke Power," Rogers said, "is that they treat us as if we could buy power somewhere else." For West and the rest of his teammates, that's evidence enough that Duke's efforts to deliver superior customer service are successful.



Commitment To Excellence Enhances Quality of Operations

The commitment to excellence at Duke Power is not limited to situations like the one in Greenwood. Through the years, Duke Power's employees have worked hard to produce electricity efficiently and safely. Those efforts continued to pay off in 1993 with successes throughout the system.

Duke Power's fossil-fueled generating system was recognized again by *Electric Light & Power* magazine as the most efficient fossil system in the country. Duke's system has achieved that honor in each of the last 19 years.

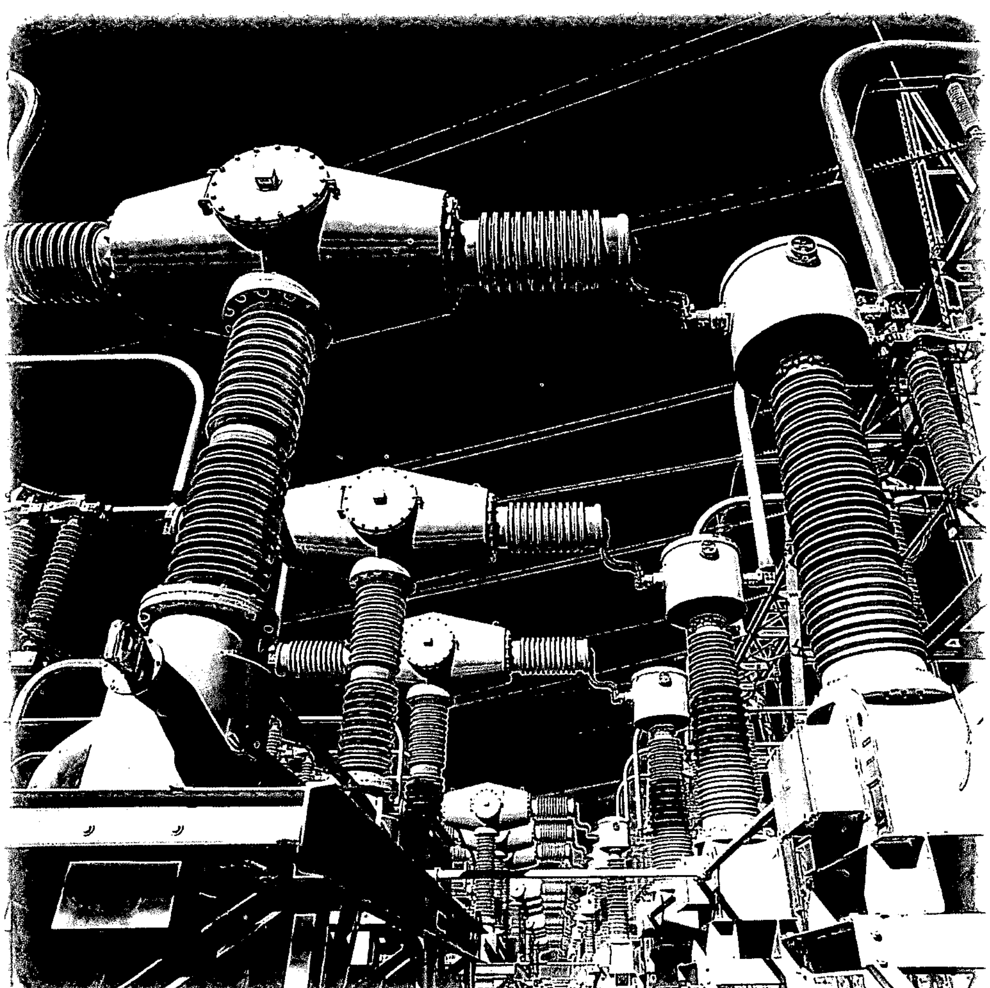
The Company's nuclear system continued its tradition of operating efficiency as well. The Catawba, McGuire and Oconee nuclear stations collectively operated at 78 percent of capacity for the year, in comparison with the industry's most current average capacity factor of 71 percent for 1992.

With a combined capacity of 17,845,000 kilowatts, Duke Power's fossil, nuclear and hydroelectric generating units create a highly efficient and reliable system to meet customers' needs. System efficiency will be a key component in the Company's ability to compete in the future, because it will help determine Duke's ability to deliver power at a competitive price. The Federal Energy Regulatory Commission broadened the requirements for wheeling electricity, so wholesale customers have the option of selecting their supplier. It is in the Company's interest to see that it offers quality service at competitive prices so customers will choose Duke Power.

Besides striving to contain operating and maintenance expenses, the Company employs a variety of options to encourage operating efficiency. These include buying power from other producers, offering customers a number of options to reduce peak load and extending the fuel cycle at the Company's nuclear plants.

Duke plans to apply to extend the 40-year licenses of its nuclear plants. The Company will first request relicensing for Unit 1 at Oconee Nuclear Station, whose operating license runs until 2013. The Company is confident that, with proper maintenance, its nuclear stations can continue to operate safely and efficiently.

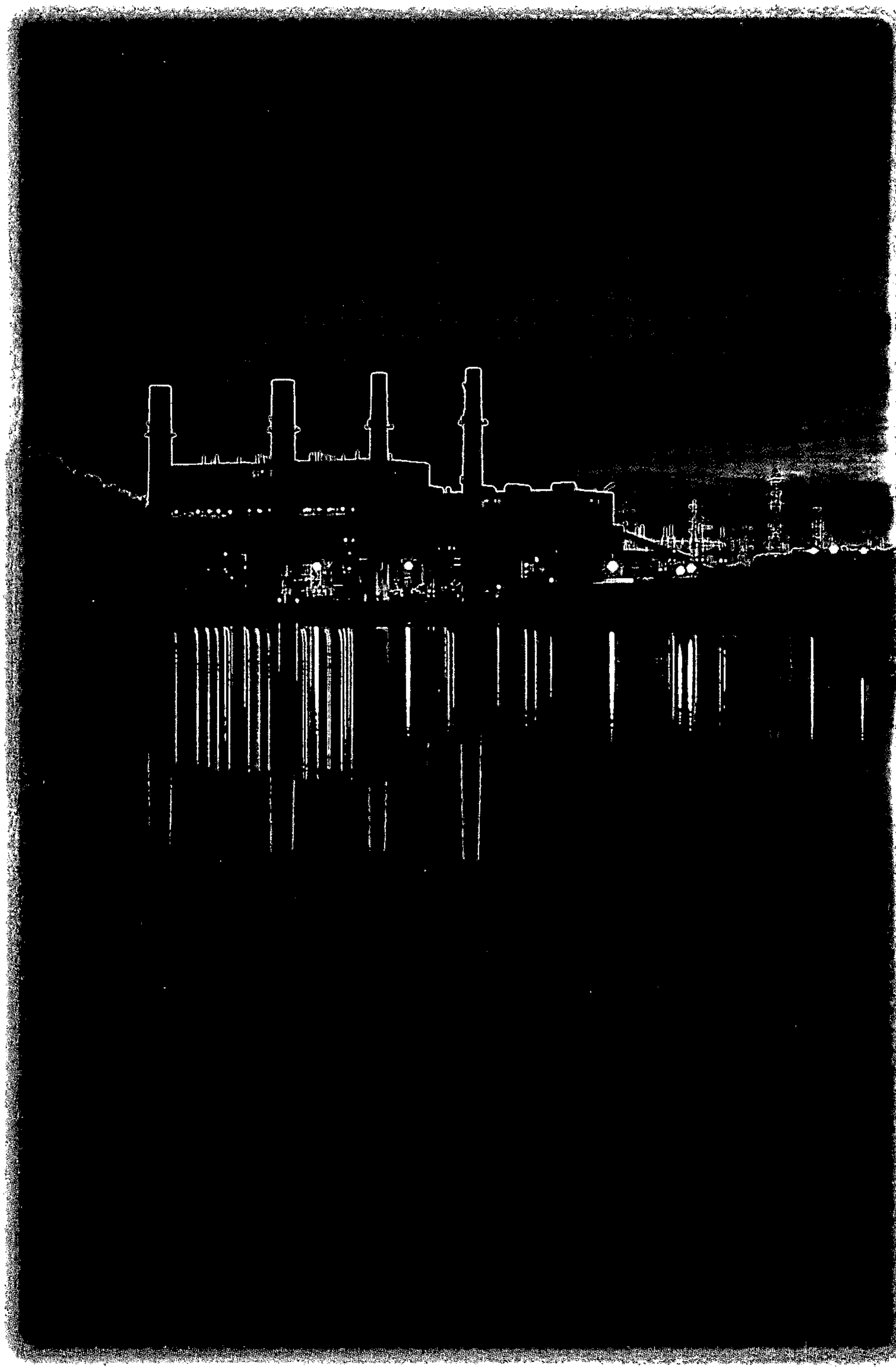
Projected growth in demand indicates that Duke Power will need to build a new fossil-fueled plant to meet base-load demand shortly after the turn



The switchyard at Catawba Nuclear Station is the link between the station and Duke Power's transmission grid. Collectively, the Catawba, McGuire and Oconee nuclear stations operated at 78 percent of capacity during 1993.

of the century. In the meantime, the Company is building the 16-unit Lincoln Combustion Turbine Station in Lincoln County, N.C., to address continued growth in peak demand. Current plans are to install 10 units in 1995 and six more in 1996. When completed, the station will provide 1,184,000 kilowatts of peaking power.

Planning for replacing steam generators on Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station continued in 1993. The steam generators are being replaced because of cracking in tubing inside the generators. While the units can be maintained and continue to operate safely, maintenance can be expensive, and tube cracking can lead to decreased operating availability. The current schedule calls for steam generator replacement at McGuire Unit 1 to begin in 1995, Catawba Unit 1 in 1996 and McGuire Unit 2 in 1997. The Company is confident that replacement of the steam generators will allow the units to continue to run efficiently and safely.



In 1993, two units at Marshall Steam Station on Lake Norman were named the two most efficient investor-owned fossil-fueled generating units in the country, helping the Duke Power fossil-fueled generating system again earn Electric Light & Power magazine's top rating as most efficient in the country.

Another issue facing the nuclear power industry is planning for the eventual decommissioning of nuclear generating stations. The Nuclear Regulatory Commission requires the Company to set aside funds for decommissioning. The current estimate for these expenses is $955 million in 1990 dollars. At the end of 1993, the total balance of the Company's decommissioning funds was $319 million, with $119 million of that amount in external trust accounts and the balance reserved internally for that purpose when needed.

Duke Power is currently recovering decommissioning costs through rates approved by the utilities commissions. The Company believes it is adequately providing for these costs over the licensed operating period of the nuclear plants.

Teamwork Solves Aluminum Plating Problem At Belews Creek

Plating of aluminum on turbine blades decreased efficiency and output of generators at the Belews Creek Steam Station until a quality improvement team found a solution to the problem.

The Team

Bill Booker
Dave Brindle
Chuck Cook
Phil Gonwa
Bob Helms
Garry Honeycutt
Len Kirschbrown
Jim Mathews
John Plaxco
Ronnie Tolbert

The quest for excellence at Duke Power depends greatly on the work of quality improvement teams (QITs) formed to tackle specific problems. A team may work a few weeks or many months, depending on the job. Time and again, QITs like the Belews Creek Aluminum Reduction QIT are proving that teammates, armed with knowledge and the power to effect change, deliver.

At the Belews Creek Steam Station, the challenge was to remove trace aluminum particles from the water the station uses to produce steam. The existing process allowed aluminum to build up on the turbine blades, causing losses in efficiency and generating capacity.

The QIT members were chosen on the basis of each member's experience and expertise and included everyone who would have a role in eliminating the problem, according to Technical Services Manager Jim Mathews, the team's sponsor. Members included team leader Len Kirschbrown; Bill Booker, instrumentation; Dave Brindle, equipment; Chuck Cook, design technician; Bob Helms, instrumentation engineer; Phil Gonwa, instrumentation and controls; Garry Honeycutt, systems engineer; John Plaxco, controls engineer and Ronnie Tolbert, chemistry lab.

"Usually, we approach a problem like this by having each person complete his or her task and then pass the project on to someone else. This time everyone worked together on it," Mathews said.

The advantage to the team approach is that it streamlined the decision-making process, since everyone involved could make suggestions early in the process. The team adapted a problem-solving technique used throughout the Company to identify and prioritize problems. As with many teams, initial progress was slow.

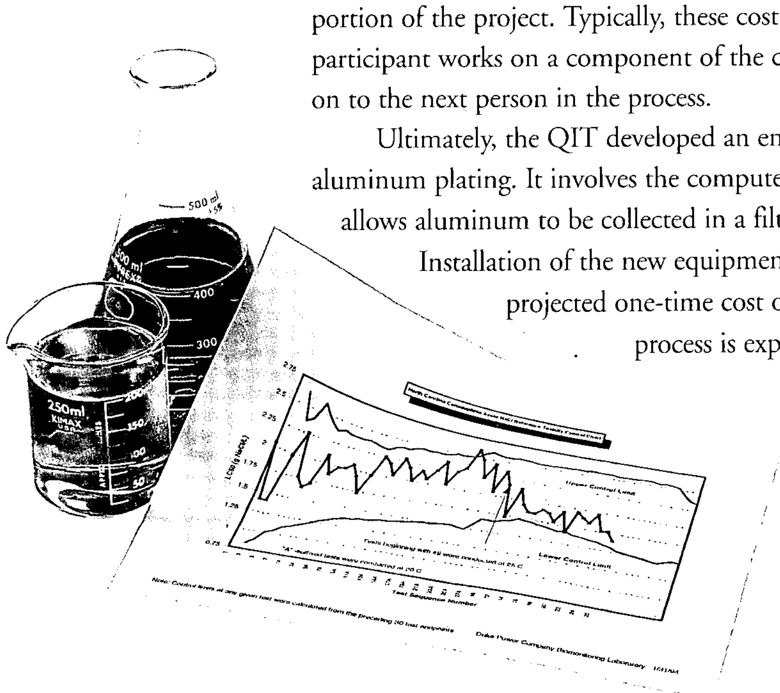
"As far as quality improvement went, our task was fairly straightforward. We knew what the goal was, but we had to finalize it. We had to work through how to get there," Kirschbrown said.

"About halfway through the project, I felt that we were finally beginning to work as a team," Kirschbrown said. "At that point, we really began to make progress."

For example, in one two-hour session, the team completed a cost analysis of a portion of the project. Typically, these cost analyses take up to four weeks because a participant works on a component of the cost estimate individually before passing it on to the next person in the process.

Ultimately, the QIT developed an entirely new solution to the problem of aluminum plating. It involves the computer-controlled injection of a polymer that allows aluminum to be collected in a filter before it can reach the turbine.

Installation of the new equipment was completed at the end of 1993. The projected one-time cost of the solution is about $97,000. The new process is expected to save the Company about $1.5 million a year.



Seeking A Competitive Advantage Through Environmental Quality

Whether it is by generating electricity through its nuclear plants, burning low-sulfur coal in its fossil-fueled units or recycling tons of material every year, Duke Power's commitment to environmental quality is evident in almost every facet of the Company's operations.

Duke Power believes its commitment to the environment is not only the right thing to do, but that it can also lead to a competitive advantage in the marketplace. The Company's credibility with the public and environmental agencies can contribute to the success of its licensing and permitting efforts, allowing Duke to respond more quickly to market and regulatory demands.

During 1993, the Company created a system for environmental benchmarking. In that effort, Duke representatives contacted recognized corporate leaders in the field such as Dow Chemical Co., Pacific Gas & Electric Co., Procter & Gamble, Southern California Edison and 3M. In addition, they distributed a mail survey to about 200 other companies and received responses from nearly half of those. The information collected in the benchmarking effort will be compared to Duke's procedures. The goal of the effort is to continuously fine-tune Duke Power's environmental policies and practices.

As a result of the 1990 amendments to the Clean Air Act, the federal government approved a system of emissions allowances for fossil-fueled generating plants to create a nationwide cap on total sulfur dioxide emissions. Duke Power purchased 25,000 allowances at the first Environmental Protection Agency-sponsored auction. The Company will use these and any other allowances purchased to comply with the Clean Air Act, in conjunction with other options available to the Company

New burners in the boilers at Riverbend Steam Station will let the plant generate electricity more cleanly by reducing nitrous oxide emissions.

such as installing scrubbers and using coal containing even less sulfur than the one-percent coal that Duke now uses.

THE QUEST FOR EXCELLENCE CONTINUES Duke Power Company's long-term effort to position itself as the Company of Choice continued in 1993. Duke Power remains sure of its goal and clear in its vision: To be the supplier of choice by customers, the employer of choice by its employees and the communities it serves, the investment of choice by shareholders and the model of integrity and excellence for business and industry.

As the Company strives to reach its goal, the challenge each year has been to stay in front of the improvements made by Duke's competitors. To do that, teammates are learning to challenge and improve old ways of doing work. Examples of improvement are evident across Duke Power, not just at Belews Creek and in Greenwood. The Fall Protection Team created new safety procedures designed to protect line technicians and promote 100 percent fall protection (see story on page 18). Another team from the transportation department worked to reduce unnecessary preventive maintenance tasks on Company vehicles while increasing service and exceeding customers' expectations. As a result of their efforts, the most common preventive maintenance procedure was reduced from 26 checks completed in 1.5 hours to 19 checks completed in 30 minutes or less.

The joint efforts of Duke Power and Crescent Resources to protect the Whitewater River corridor won a merit award from the South Carolina Chapter of the Soil and Water Conservation Society. This bridge over the Whitewater River is part of a hiking trail contributed by Duke Power and Crescent.

The Projections Improvement Team improved the accuracy of financial projections and the quality and usefulness of budget variance explanations. The New Service Application Process Team examined how the Company provides service to new customers, with a goal of reducing both costs and the complexity of the application process. They achieved the goal by reducing the number of questions on an application from 32 to seven, in part by using credit checking capabilities already in place.

Successes like these are concrete examples that Duke employees have embraced quality principles and are using them to benefit customers, shareholders and themselves. As teammates' continuous improvement skills increase, the Company is preparing for the next level of improvement in which teammates will focus on improving the systems and processes that drive their work, while reducing cycle time and eliminating unnecessary work.

In 1994, Duke Power moves into a year of evaluation. The year will be a time of evaluating the progress made, determining ways to progress more quickly and planning for the challenges those efforts present. During the year, the Company intends to expand its use of quality improvement teams to include suppliers and customers; to better link compensation, performance management and budgeting to the Company's Corporate Strategic Plan and to begin certifying vendors and suppliers as "suppliers of excellence," indicating that they too embrace the principles of quality.

These goals and others are part of a year in which the Company intends to take stock of all it has accomplished to date in its journey to excellence. Much is still to be done, but the sense of excitement within the Company is impossible to miss.

New Safety Procedures Make Climbing Safer

New safety procedures and newly designed safety belts are making the job of climbing transmission towers safer for Duke Power's line technicians.

__The Team__

Mike Atkins
Maxie Bailey
Roy Birmingham
Oren Brown
Brent Dagenhart
Tim Davis
Billy George
John Gilstrap
John Graham
Rick Henson
Al Jackson
Wayne Kerley
Tom Kincaid
Jim Lyerly
Gary Montgomery
Grady Nivens
Dee Putnam
Ronnie Rose
Ken Rowland
Bill Sain
Robert Teague
Joni Truss
Thomas Watts
George White
Danny Wilson
Danny Woods

When a 58-foot fall from a transmission tower paralyzed a Duke Power line technician who was wearing a safety belt, Dee Putnam took on the task of investigating the accident and finding a way to avoid similar incidents. The job took a year, with Putnam — Supervisor, Distribution Methods — reviewing and rejecting a number of alternate safety climbing devices available from manufacturers.

Putnam and others at Duke were not satisfied with the equipment available from national manufacturers. The best way to prevent falls was through a combination of equipment and completely rewritten safety procedures designed to provide 100 percent fall protection.

"I agreed to work on it, but I knew it was too big a job for just one person, so we created the Fall Protection Team," Putnam said.

Two subteams worked on the project. Besides Putnam, the first subteam consisted of Maxie Bailey, Roy Birmingham, Brent Dagenhart, Billy George, Rick Henson, Al Jackson, Wayne Kerley, Jim Lyerly, Ronnie Rose, Bill Sain, Robert Teague, Joni Truss, Thomas Watts, George White, Danny Wilson and Danny Woods. Most of the members were either line technicians or employees whose jobs required them to climb from time to time.

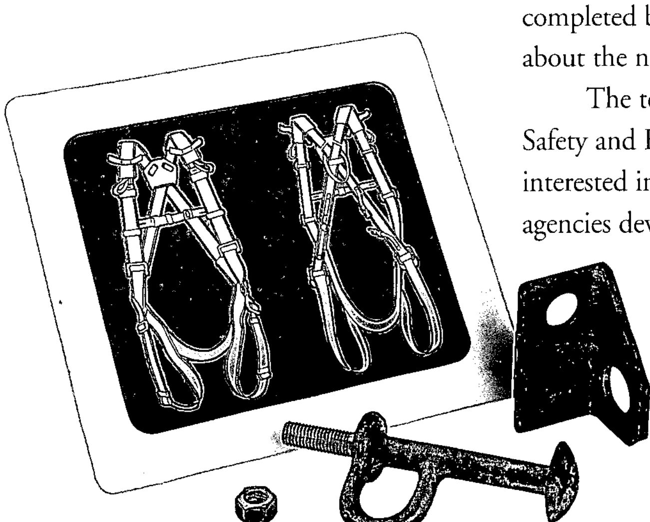
As part of their work, team members performed a job and task analysis for work performed on the Company's transmission towers.

"We learned that for just those activities alone there are about 85 to 90 climbing jobs that technicians perform," Putnam said. A second group of field technicians analyzed jobs performed around power substations and other power apparatus. Team members Mike Atkins, Oren Brown, Tim Davis, John Gilstrap, John Graham, Tom Kincaid, Gary Montgomery, Grady Nivens, Ronnie Rose and Ken Rowland pointed out another 150 clearly defined climbing tasks.

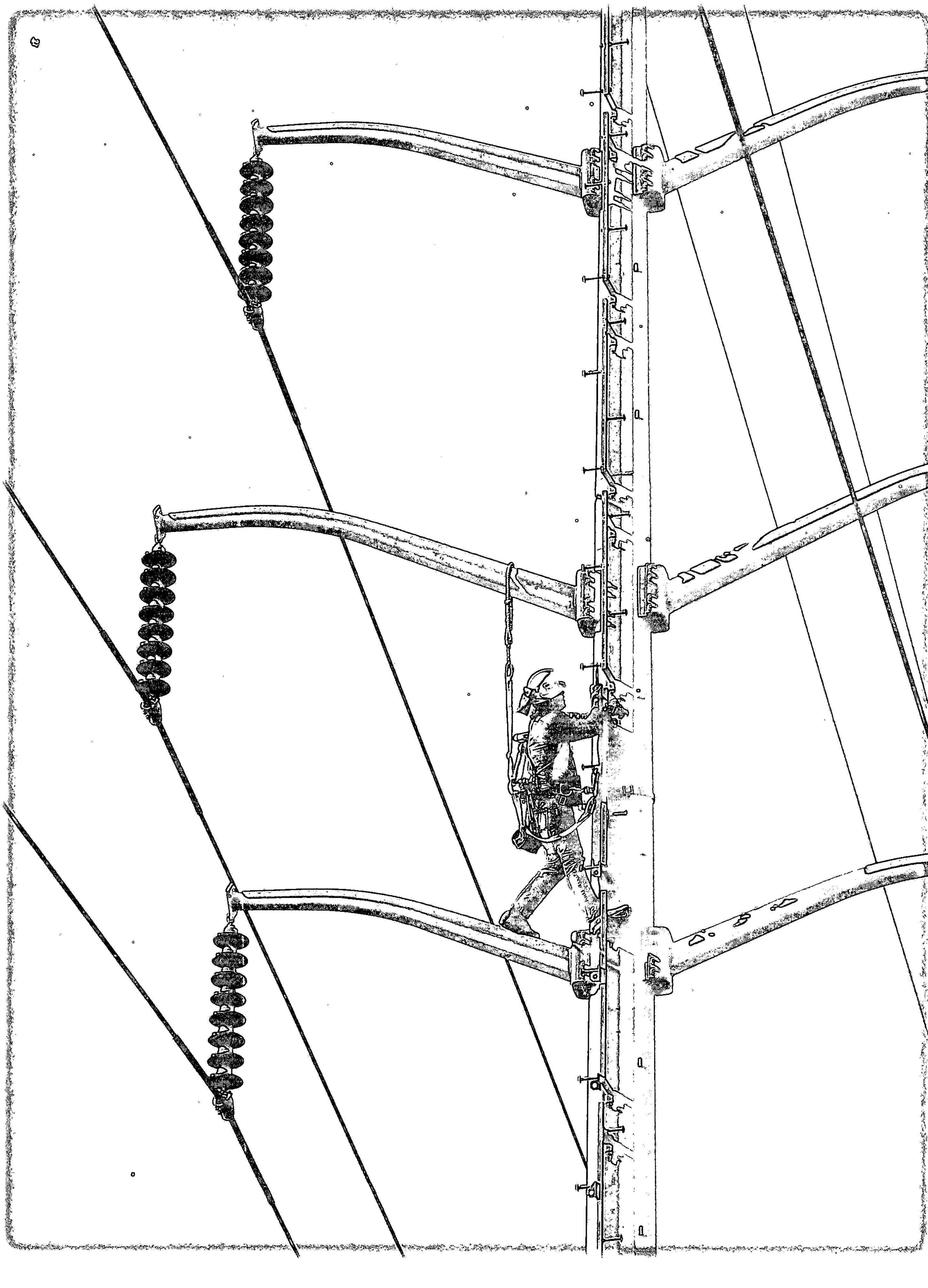
By pinpointing all the tasks that technicians perform, the team had a better understanding of the requirements for equipment and procedures to promote 100 percent fall protection without encumbering work aloft. They then developed new safety equipment, working in conjunction with safety equipment manufacturers nationally and internationally, and completely rewrote the safety procedures for using the newly designed equipment.

The new procedures have been implemented, and training is expected to be completed by mid-1994. Putnam said that all who've had the training are enthusiastic about the new equipment and procedures.

The team's work is attracting outside attention. Officials of the Occupational Safety and Health Administration in both North Carolina and Washington, D.C., are interested in their work and have approached Duke Power about helping those agencies develop fall protection guidelines and train their inspectors.



Putnam is blunt about the team's work and its impact on the safety of utility work. "Safety is a top priority at Duke Power," Putnam said. "It's up to us to give our people the best equipment and training we can provide."



Glossary

Annual Total Return to Shareholders	Annualized change in value from stock price change and dividend reinvestment.
Base Load	Amount of electric power delivered or needed at the lowest point of demand during the day. Base load, therefore, must be met 24 hours a day. At Duke Power, base-load demand is met primarily by the Company's nuclear generating stations.
Decommission	To permanently remove a generating station from service and restore the station site to a condition that allows unrestricted use.
Dividend Payout Ratio	The portion of earnings available for common stock which is paid to common shareholders in dividends. The ratio is calculated by dividing dividends per common share by earnings per common share.
Fixed Charges Coverage	Calculated by dividing earnings before taxes and interest expense by interest expense. This is an indicator of credit quality commonly used by investors.
Embedded Cost of Debt	Calculated by dividing interest expense and other debt costs by long-term debt outstanding. This cost is a component of the total cost of capital.
Embedded Cost of Preferred Stock	Calculated by dividing the preferred stock dividends paid and other preferred stock costs by the amount of preferred stock outstanding. This cost is a component of the total cost of capital.
Indicated Annual Dividend	The most recently declared quarterly dividend rate per common share multiplied by four.
Peak Load	Amount of electricity required during periods of highest demand. Peak periods fluctuate by season, generally occurring in the morning hours in winter and in late afternoon during the summer. At Duke Power, peak demand is met by power generated by base load stations plus the Company's coal-fired units, hydroelectric stations and combustion turbine units.
Return on Average Common Equity	A measure of profitability calculated by dividing annual earnings for common stock by the average of common stock equity.
Steam Generators	On a nuclear generator, large heat exchangers that transfer heat from water heated by the nuclear reactor to water used to create steam for generating electricity.

Consolidated Statements of Income

Dollars in Thousands — Year ended December 31	1993	1992	1991
Electric revenues (Notes 1 and 2)	$4,281,876	$3,961,484	$3,816,960
Electric expenses			
Operation			
Fuel used in electric generation (Note 1)	732,246	659,593	657,725
Net interchange and purchased power (Note 3)	535,033	540,840	545,840
Wages, benefits and materials	701,994	636,729	622,121
Maintenance of plant facilities	375,457	403,162	354,679
Depreciation and amortization (Note 1)	488,441	491,339	431,624
General taxes	231,680	215,493	204,688
Income taxes (Notes 1 and 4)	402,960	289,633	293,460
Total electric expenses	3,467,811	3,236,789	3,110,137
Electric operating income	814,065	724,695	706,823
Other income (Notes 1, 4, 11 and 14)			
Allowance for equity funds used during construction	17,221	15,476	50,704
Other, net	61,769	83,216	102,884
Income taxes — other, net	(24,092)	(27,475)	(25,472)
Income taxes — credit	16,371	13,790	22,789
Total other income	71,269	85,007	150,905
Income before interest deductions	885,334	809,702	857,728
Interest deductions			
Interest on long-term debt	256,347	265,646	274,662
Other interest	12,431	41,736	18,834
Allowance for borrowed funds used during construction (Notes 1 and 4)	(9,859)	(5,763)	(19,391)
Total interest deductions	258,919	301,619	274,105
Net income	626,415	508,083	583,623
Dividends on preferred and preference stock	52,429	56,407	54,683
Earnings for common stock	$ 573,986	$ 451,676	$ 528,940
Common stock data (Note 6)			
Average shares outstanding (thousands)	204,859	204,819	203,431
Earnings per share	$2.80	$2.21	$2.60
Dividends per share	$1.84	$1.76	$1.68

See Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Dollars in Thousands — Year ended December 31,	1993	1992	1991
Cash flows from operating activities			
Net Income	$ 626,415	$ 508,083	$ 583,623
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash items			
Depreciation and amortization (Note 1)	657,068	660,896	619,823
Deferred income taxes and investment tax credit, net of amortization (Note 4)	56,315	44,518	27,456
Allowance for equity funds used during construction	(17,221)	(15,476)	(50,704)
Purchased capacity levelization (Note 3)	(20,049)	(66,511)	(70,605)
Other, net (Note 15)	36,864	(16,258)	(32,149)
(Increase) Decrease in			
Accounts receivable	(36,948)	14,255	(45,412)
Inventory	29,150	(9,383)	6,866
Prepayments	(452)	(939)	181
Increase (Decrease) in			
Accounts payable	(54,275)	69,739	44,265
Taxes accrued (Notes 1 and 4)	26,583	4,514	11,739
Interest accrued and other liabilities (Notes 1, 9 and 13)	30,185	(22,825)	12,863
Total adjustments	707,220	662,530	524,323
Net cash provided by operating activities	1,333,635	1,170,613	1,107,946
Cash flows from investing activities			
Construction expenditures	(543,563)	(465,292)	(572,705)
Investment in nuclear fuel	(111,731)	(122,565)	(183,803)
External funding for decommissioning (Note 16)	(52,524)	(61,246)	—
Pre-funded pension cost (Note 12)	(50,000)	—	—
Net change in investment securities and joint ventures (Notes 1, 11 and 15)	(12,379)	(96,475)	(35,807)
Net cash used in investing activities	(770,197)	(745,578)	(792,315)
Cash flows from financing activities			
Proceeds from the issuance of			
First and refunding mortgage bonds	1,395,682	926,650	414,297
Preferred stock	215,633	281,089	—
Pollution-control bonds	76,265	—	—
Short-term notes payable, net (Note 5)	(108,000)	40,000	(99,000)
Common stock	—	—	48,014
Payments for the redemption of			
First and refunding mortgage bonds	(1,399,336)	(1,013,218)	(279,970)
Preferred stock	(224,295)	(246,414)	(9,650)
Pollution-control bonds	(79,310)	—	—
Dividends paid	(427,868)	(417,443)	(381,589)
Other (Note 15)	(5,926)	3,313	(5,662)
Net cash used in financing activities	(557,155)	(426,023)	(313,560)
Net increase (decrease) in cash	6,283	(988)	2,071
Cash at beginning of year	9,293	10,281	8,210
Cash at end of year	$ 15,576	$ 9,293	$ 10,281

See Notes to Consolidated Financial Statements

Consolidated Balance Sheets

Assets

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

Capitalization and Liabilities

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

See Notes to Consolidated Financial Statements.

Consolidated Statements of Capitalization and Retained Earnings

Dollars in Thousands December 31,	1993	1992
Capitalization		
Common stock equity (Notes 6 and 7)		
Common stock, no par, 300,000,000 shares authorized; 204,859,339 shares outstanding for 1993 and 1992	$1,926,909	$1,926,909
Retained earnings	2,410,825	2,223,718
Total common stock equity	4,337,734	4,150,627
Preferred and preference stock without sinking fund requirements (Note 7)	500,000	500,000
Preferred stock with sinking fund requirements (Notes 8 and 10)	281,000	279,519
Long-term debt (Notes 9, 10 and 15)		
Parent company long-term debt	3,199,032	3,202,437
Subsidiary long-term debt	86,365	85,674
Total consolidated long-term debt	3,285,397	3,288,111
Total capitalization	$8,404,131	$8,218,257

Dollars in Thousands Year ended December 31,	1993	1992	1991
Retained Earnings			
Balance — Beginning of year	$2,223,718	$2,141,259	$1,953,779
Add — Net income	626,415	508,083	583,623
Total	2,850,133	2,649,342	2,537,402
Deduct			
Dividends			
Common stock	376,937	360,475	341,801
Preferred and preference stock	52,429	56,407	54,683
Capital stock transactions, net	9,942	8,742	(341)
Total deductions	439,308	425,624	396,143
Balance — End of year	$2,410,825	$2,223,718	$2,141,259

See Notes to Consolidated Financial Statements.

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 $175,726,000 and $167,610,000 as of December 31, 1993 and 1992, respectively, for service that has been rendered but not yet billed to customers.

B. Additions to Electric Plant

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

C. Allowance for Funds Used During Construction (AFUDC)

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

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

D. Depreciation and Amortization

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

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

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

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

E. Subsidiaries

The Company's consolidated financial statements reflect consolidation of all of its wholly-owned subsidiaries. Intercompany transactions have been eliminated in consolidation. (See Note 11 and "Subsidiary Highlights," page 43.)

F. Income Taxes

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

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

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

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

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 July 1987 assuring the legality of such adjustments in rates. In 1991, the statute was extended through June 30, 1997.

I. Consolidated Statements of Cash Flows

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

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

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

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 only requests for general rate increases since 1986. The rate increase requested by the Company in North Carolina was 9.22 percent; a 4.15 percent increase was granted resulting in $100.1 million in additional annual revenues. In South Carolina, a rate increase of 7.29 percent was requested; a 3.0 percent increase was granted resulting in $30.2 million in additional annual revenues. These increases were requested primarily to recover costs associated with the Bad Creek Hydroelectric Station.

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

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

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

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 the Catawba Nuclear Station. As of December 31, 1993, $498,930,000 of Electric plant in service and Nuclear fuel

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

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

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

Effective in its November 1991 rate order, the North Carolina Utilities Commission (NCUC) reaffirmed the Company's recovery, on a levelized basis, of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners. The new NCUC rate order changed the levelized basis to a 15-year period ending 2001 for all of the other joint owners compared to the previous 15-year levelization period for NCMPA and PMPA and 10-year levelization period for NCEMC and Saluda River. The Public Service Commission of South Carolina (PSCSC), in its November 1991 rate order, reaffirmed the 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 for PMPA and NCMPA; for NCEMC and Saluda River, the new levelized basis reflects the projected purchased capacity payments for the twelve-month period ended October 1992. The Federal Energy Regulatory Commission granted the Company recovery on a levelized basis of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners over their contractual purchased power buyback periods. As currently provided in rates in all jurisdictions, the Company recovers the costs of purchased energy and a portion of purchased capacity. The portion of costs not currently recovered through rates is being accumulated, and the Company is recording a carrying charge on the accumulated balance. The Company recovers the accumulated balance including the carrying charge when the capacity payments drop below the levelized revenues. In the North Carolina and wholesale jurisdictions, purchased capacity payments continue to exceed levelized revenues. In the South Carolina jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments. Jurisdictional levelizations are intended to recover total costs, including allowed returns, and are subject to adjustments, including final true-ups.

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

Note 4. Income Tax Expense

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

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

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

(continued from page 27)

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

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

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

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

	1993	1992	1991
Income taxes related to electric expenses			
Current income taxes			
Federal	$278,279	$215,726	$232,121
State	60,948	47,116	54,335
	339,227	262,842	286,456
Deferred taxes, net			
Excess tax over book depreciation	60,760	86,046	60,976
Loss on bond redemptions	33,016	9,950	1,995
Pre-funded pension cost	19,751	—	—
Amortization of canceled construction costs	(17,890)	(23,959)	(23,959)
Deferred Catawba purchased capacity costs	2,841	7,271	8,163
Property taxes	(5,806)	(15,499)	(11,987)
Other	(17,682)	(25,756)	(16,977)
	74,990	38,053	18,211
Investment tax credit			
Deferred	—	—	2,273
Amortization of deferrals (credit)	(11,257)	(11,262)	(13,480)
	(11,257)	(11,262)	(11,207)
Total income taxes related to electric expenses	402,960	289,633	293,460
Income taxes related to other income			
Income taxes — return on deferred Catawba purchased capacity costs	20,702	18,845	20,675
Income taxes — other, net	3,390	8,630	4,797
Income taxes — (credit)	(16,371)	(13,790)	(22,789)
Total income taxes related to other income	7,721	13,685	2,683
Total income tax expense	$410,681	$303,318	$296,143

Total current income taxes were $354,366,000 for 1993, $258,800,000 for 1992 and $268,686,000 for 1991. Of these amounts, state income taxes were $61,237,000 for 1993, $44,149,000 for 1992 and $48,671,000 for 1991.

Total deferred income taxes were $67,572,000 for 1993, $55,780,000 for 1992 and $38,664,000 for 1991. Of these amounts, deferred state income taxes were $14,279,000 for 1993, $13,786,000 for 1992 and $10,833,000 for 1991.

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

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

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

Note 5. Short-Term Borrowings and Compensating-Balance Arrangements

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

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

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

	December 31, 1993	December 31, 1992	December 31, 1991
Amount outstanding at end of period — average rate of 3.27% as of December 31, 1993, 3.57% as of December 31, 1992 and 4.65% as of December 31, 1991	$ 18,000	$126,000	$ 86,000
Maximum amount outstanding during the period	$178,000	$219,000	$285,500
Average amount outstanding during the period	$ 35,187	$ 48,851	$ 92,090
Weighted-average interest rate for the period — computed on a daily basis	3.17%	4.02%	6.47%

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 1991 through 1993.

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

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

Retained Earnings

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

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, 1993 and 1992:

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

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

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

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

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

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, 1993 and 1992:

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

Preferred stock with sinking fund requirements as of December 31, 1993 and 1992, was as follows (dollars in thousands):

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

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

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

Note 9. Long-Term Debt

Long-term debt outstanding as of December 31, 1993 and 1992, was as follows (dollars in thousands):

Series	Year Due	1993	1992
First and refunding mortgage bonds:			
6.06%-6.23%	1994	$ 81,700	$ 81,700
6.47%-6.60%	1995	40,300	40,300
4 1/2%	1995	40,000	40,000
6.59%	1996	3,000	3,000
7 7/8%	1996	—	100,000
5 3/8%	1997	72,600	72,600
5 5/8%	1997	100,000	100,000
6 3/8%	1998	—	68,500
5.17%	1998	50,000	—
7%	1999	—	56,075
7.5%	1999	100,000	100,000
6 1/4%	1999	65,000	65,000
5.76%	1999	5,000	—
5.78%	1999	25,000	—
5.79%	1999	30,000	—
7%	2000	100,000	100,000
7% B	2000	100,000	100,000
7 1/2%	2001	—	97,900
7 3/8% B	2001	—	38,050
5 7/8%	2001	150,000	—
7 3/4%	2002	—	78,100
7 3/8% B	2002	—	67,900
6 5/8% B	2003	100,000	—
7 3/4%	2003	—	94,872
5 7/8% C	2003	75,000	—
6.125%	2003	75,000	—
8%	2004	75,000	75,000
6 1/4% B	2004	100,000	—
7.37%-7.41%	2004	100,000	100,000
7%	2005	200,000	200,000
8 1/8%	2007	—	119,500
6 3/8%	2008	125,000	—
9%	2016	—	175,000
8 1/2%	2017	—	150,000
9 5/8%	2020	46,982	200,000
10 1/8% B	2020	24,854	150,000

Series	Year Due	1993	1992
(continued)			
8 3/4%	2021	$ 150,000	$ 150,000
8 3/8% B	2021	150,000	150,000
8 5/8%	2022	100,000	100,000
7 3/8%	2023	200,000	—
6 7/8%	2023	200,000	—
6 3/4%	2025	150,000	—
8.95%	2027	15,851	15,925
7%	2033	150,000	—
Pollution-Control bonds:			
9 1/8%	2013	—	77,000
7.70%	2012	20,000	20,000
7.75% B	2017	10,000	10,000
7.50%	2017	25,000	25,000
2.55%	2014	40,000	—
2.60%	2014	—	40,000
5.80%	2014	77,000	—
Subtotal		3,172,287	3,061,422
Other long-term debt:			
Capitalized leases		47,029	53,782
Other long-term debt		130,000	130,000
Unamortized debt discount and premium, net		(61,128)	(35,940)
Current maturities of long-term debt		(89,156)	(6,827)
Subtotal (a)		3,199,032	3,202,437
Subsidiary long-term debt:			
Crescent Resources, Inc. (b)		54,149	53,207
Nantahala Power and Light (c)		33,458	33,574
Current maturities of long-term debt		(1,242)	(1,107)
Subtotal		86,365	85,674
Total consolidated long-term debt		$3,285,397	$3,288,111

(a) Substantially all the Company's electric plant was mortgaged as of December 31, 1993.
(b) Substantial amounts of Crescent Resources, Inc.'s real estate development projects, land and buildings are pledged as collateral.
(c) Nantahala Power and Light's loan agreements impose net worth restrictions and limitations on disposal of assets and payment of cash dividends.

As of December 31, 1993 and 1992, the Company had $40,000,000 in pollution-control revenue bonds backed by an unused, two-year revolving credit facility of $40,000,000 and $130,000,000 in commercial paper backed by an unused, three-year $130,000,000 revolving credit facility. These facilities are on a fee basis. Both the $40,000,000 in pollution-control bonds and the $130,000,000 in commercial paper are included in long-term debt.

As of December 31, 1993, Crescent Resources, Inc. had $52,064,000 in mortgage loans which mature in 1997 and require monthly payments of principal. Interest rates are variable and ranged from 4.21 percent to 5.08 percent as of December 31, 1993. Nantahala Power and Light had $33,000,000 in senior notes maturing in 2011 and 2012 as of December 31, 1993. The two notes carry fixed interest rates of 9.21 percent and 7.45 percent and require prepayments beginning 1997 and 1998, respectively.

The annual maturities of consolidated long-term debt, including capitalized lease principal payments through 1998, are $90,398,000 in 1994; $89,888,000 in 1995; $13,264,000 in 1996; $223,810,000 in 1997 and $54,522,000 in 1998.

Note 10. Fair Value of Financial Instruments

Estimated fair value amounts have been determined by the Company using available market information and appropriate valuation methodologies. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 1993, are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

Cash, Short-term investments and Notes payable
The carrying amount approximates fair value because of the short maturity of these instruments.

Long-term debt (excluding Capitalized leases) and Preferred stock with sinking fund requirements
Fair value is based on market price estimates. As a result of substantial refinancing activity in 1993 and 1992, the Company's book value of consolidated long-term debt and preferred stock is not materially different from fair market value as of December 31, 1993.

Nuclear decommissioning trust funds
External funds have been established, as required by the Nuclear Regulatory Commission, as a mechanism to fund certain costs of nuclear decommissioning. (See Note 16.) These nuclear decommissioning trust funds are primarily invested in intermediate-term municipal bonds. As of December 31, 1993, the Company's book value of its nuclear decommissioning trust funds is not materially different from fair market value.

Note 11. Investment in Joint Ventures

Certain investments in joint ventures are accounted for by the equity method. The Company's ownership in domestic and international joint ventures is 50 percent or less. Total assets of these joint ventures as of December 31, 1993 and 1992, were $972 million and $433 million, respectively. The Company's proportionate share of these assets was $241 million and $163 million, respectively. Total liabilities of these joint ventures as of December 31, 1993 and 1992, were $413 million and $321 million, respectively. The Company's proportionate share of the liabilities was $139 million and $132 million, respectively. Of the $413 million total liabilities outstanding at December 31, 1993, $290 million represents non-recourse debt for which the Company bears no responsibility in the event the joint venture defaults on the debt. The Company's portion of net income from the joint ventures for the years ended December 31, 1993 and 1992, was $2,601,000 and ($1,179,000).

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. During 1993, the Company made a one-time contribution of $50,000,000 to enhance the funded position of the plan.

Net periodic pension cost for the years ended December 31, 1993, 1992 and 1991, include the following components (dollars in thousands):

	1993		1992		1991	
Service cost benefit earned during the year		$39,514		$35,701		$37,286
Interest cost on projected benefit obligation		93,347		85,613		79,175
Actual return on plan assets	(117,898)		(50,897)		(127,978)	
Amount deferred for recognition	35,652		(32,277)		52,574	
Expected return on plan assets		(82,246)		(83,174)		(75,404)
Net amortization		4,137		3,812		4,347
Net periodic pension cost		$54,752		$41,952		$45,404

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1993 and 1992, is as follows (dollars in thousands):

	1993	1992
Accumulated benefit obligation:		
Vested benefits	$(1,087,705)	$ (920,228)
Nonvested benefits	(3,946)	(2,915)
Accumulated benefit obligation	$(1,091,651)	$ (923,143)
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds	$ 1,137,992	$ 980,661
Projected benefit obligation	(1,311,921)	(1,132,410)
Unrecognized net experience loss	265,566	204,145
Unrecognized prior service cost reduction	(42,705)	(45,911)
Remaining unrecognized transitional obligation	1,068	1,202
Prepaid pension cost	$ 50,000	$ 7,687

In determining the projected benefit obligation, the weighted-average assumed discount rate used was 7.50 percent in 1993 and 8.25 percent in 1992 and 1991. The assumed increase in future compensation level for determining the projected benefit obligation is based on an age-related basis. The weighted-average salary increase was 4.50 percent in 1993, 5.40 percent in 1992 and 5.65 percent in 1991. The expected long-term rate of return on plan assets used in determining pension cost was 8.40 percent in 1993 and 9.25 percent in 1992 and 1991.

During 1993 the Company offered an enhanced early retirement option, Limited Period Separation Opportunity (LPSO), for eligible employees. The Company recorded an additional one-time expense for special termination benefits associated with LPSO of approximately $7,611,000.

B. Postretirement Benefits

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own postretirement benefit plans, currently provides certain health care and life insurance benefits for retired employees. Employees become eligible for these benefits if they retire at age 55 or greater with 10 years of service, or if they retire as early as age 51 with 30 years or more of service. Employees retiring after January 1, 1992, receive a fixed Company allowance, based on years of service, to be used to pay medical insurance premiums. The Company reserves the right to terminate, suspend, withdraw, amend or modify the plans in whole or in part at any time.

In 1992, the Company commenced funding the maximum amount allowable under section 401(h) of the Internal Revenue Code, which provides for tax deductions for contributions and tax-free accumulation of investment income. Such amounts partially fund the Company's medical and dental postretirement benefits. The Company has also established a Retired Lives Reserve, which has tax attributes similar to 401(h) funding, to partially fund its postretirement life insurance obligation. The Company contributed $14,648,000 into these funding mechanisms in 1993 and $19,338,000 in 1992.

In 1992, the Company implemented a new accounting standard that requires postretirement benefits to be recognized as earned by employees rather than recognized as paid. Prior to 1992, the cost of retiree benefits was recognized as the benefits were paid. Amounts paid by the Company for 1991 amounted to $11,900,000.

(continued from page 33)

Net periodic postretirement benefit cost for the years ended December 31, 1993 and 1992, include the following components (dollars in thousands):

	1993		1992	
Service cost benefit earned during the year		$ 4,974		$ 4,644
Interest cost on accumulated postretirement benefit obligation		25,482		23,347
Actual return on plan assets	(4,143)		(2,953)	
Amount deferred for recognition	334		1,061	
Expected return on plan assets		(3,809)		(1,892)
Straight line — 20 year amortization of transition obligation		13,479		13,479
Other amortization		278		160
Net periodic postretirement benefit cost		$ 40,404		$ 39,738

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1993 and 1992, is as follows (dollars in thousands):

	1993		1992	
Fair market value of plan assets, consisting primarily of short-term investments and cash equivalents, common stocks, real estate investments and government and industrial bonds		$ 57,840		$ 41,634
Actives eligible to retire	(21,810)		(14,954)	
Actives not eligible to retire	(90,621)		(74,900)	
Retirees and surviving spouses	(238,522)		(213,018)	
Accumulated postretirement benefit obligation		(350,953)		(302,872)
Unrecognized prior service cost		1,923		2,083
Unrecognized net experience (gain)/loss		29,127		(2,501)
Unrecognized transitional obligation		242,629		256,108
(Accrued) postretirement benefit cost		$ (19,434)		$ (5,548)

In determining the accumulated postretirement benefit obligation (APBO), the weighted-average assumed discount rate used was 7.50 percent in 1993 and 8.25 percent in 1992. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 4.50 percent in 1993, 5.40 percent in 1992 and 5.65 percent in 1991. The expected long-term rate of return on 401(h) assets used in determining postretirement benefits cost was 8.40 percent in 1993 and 9.25 percent in 1992. For Retired Lives Reserve assets, 7.125 percent was used in 1993 and 1992.

The assumed medical inflation rate was approximately 13 percent in 1993. This rate decreases by 0.5 percent to 1.0 percent per year until a rate of 5.5 percent is achieved in the year 2002, which remains fixed thereafter.

A 1.0 percent increase in the medical and dental trend rates produces a 6.25 percent ($1,903,213) increase in the aggregate service and interest cost. The increase in the APBO attributable to a 1.0 percent increase in the medical and dental trend rates is 6.69 percent ($23,483,182) as of December 31, 1993.

Note 13: Commitments and Contingencies

A. Construction Program

Projected construction and nuclear fuel costs, both including allowance for funds used during construction, are $2.3 billion and $394 million, respectively, for 1994 through 1996. The program is subject to periodic review and revisions, and actual construction costs incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

B. Nuclear Insurance

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

Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $9.4 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $9.2 billion, which will be increased by $75.5 million as each additional commercial nuclear reactor is

licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. The $9.2 billion could also be reduced by $75.5 million for certain nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs and public liability damages exceed primary insurances, licensees may be assessed up to $75.5 million for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $75.5 million amount is subject to indexing for inflation. This amount is further subject to a surcharge of 5 percent (which is included in the above $9.4 billion figure) if funds are insufficient to pay claims and associated costs. If retrospective premiums were to be assessed, the other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of such assessment.

The Company is a member of Nuclear Mutual Limited (NML), which provides $500 million in primary property damage coverage for each of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $42 million. This amount represents 5 times the Company's annual premium to NML.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases $1.4 billion of insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination, and decommissioning liability program, the Company will be liable, on a pro rata basis, for additional assessments of up to $46 million. This amount is limited to 7.5 times the Company's annual premium to NEIL for excess property, decontamination and decommissioning liability insurance. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to Catawba. The Company has also purchased an additional $400 million of excess property damage insurance for its Oconee and McGuire plants and $800 million for its Catawba plant through a pool of stock and mutual insurance companies.

The Company participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Each unit of the Oconee, McGuire and Catawba Nuclear Stations is insured for up to approximately $3.5 million per week, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100 percent for 52 weeks, and 67 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $30 million. This amount represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NEIL policies applicable to the joint ownership agreements.

C. Other

The other joint owners of the Catawba Nuclear Station and the Company are involved in various proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding is that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information, see Note 3.) The Company and two of the four joint owners have entered into a proposed settlement agreement which, if approved by the regulators, will resolve all issues in contention in such proceedings between the Company and these owners. The Company recorded a liability as an increase to Other current liabilities on its Consolidated Balance Sheets of approximately $105 million in 1993 to reflect this proposed settlement. In addition, future estimated obligations in connection with the settlement are reflected in estimates of purchased capacity obligations in Note 3. As the Company expects the costs associated with this settlement will be recovered as part of the purchased capacity levelization, the Company has included approximately $105 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

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

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

Note 14. Other Income

For the years ended December 31, 1993, 1992 and 1991, the Company reported carrying charges on purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station of $32,180,000, $28,820,000 and $28,765,000 (net of taxes), respectively, as components of "Other, net" and "Income taxes — other, net" on the Consolidated Statements of Income. (For additional information on purchased capacity levelization, see Note 3.)

Also included in "Other, net" and "Income taxes — other, net" on the Consolidated Statements of Income is income provided by diversified activities and the Company's subsidiaries of $21,996,000, $25,728,000 and $23,587,000 (net of taxes) for years ended December 31, 1993, 1992 and 1991, respectively. The activities of Crescent Resources, Inc., the Company's real estate development and forest management subsidiary, generated the majority of subsidiary and non-electric earnings. Other components include subsidiary investment income, fees for engineering services, construction and operation of generation and transmission facilities outside the Company's current service area, water operations and merchandising.

For the year ended December 31, 1991, the Company recorded a net of tax carrying charge of $36,765,000 on costs incurred on the Bad Creek Hydroelectric Station after commercial operation but prior to recovery of costs through rates. This carrying charge is a component of "Other, net" in the Consolidated Statements of Income.

Note 15. Reclassification

In the Consolidated Statements of Cash Flows, Consolidated Balance Sheets and the Consolidated Statements of Capitalization, certain prior-year information has been reclassified to conform with 1993 classifications.

Note 16. Nuclear Decommissioning Costs

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

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

Independent Auditors' Report

Duke Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Duke Power Company and subsidiaries (the Company) as of December 31, 1993 and 1992, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1993. 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, 1993 and 1992, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

As discussed in Note 4 to the consolidated financial statements, the Company changed its method of accounting for income taxes to conform with Statement of Financial Accounting Standards No. 109.

Deloitte & Touche

Deloitte & Touche
Charlotte, North Carolina
February 11, 1994

Responsibility for Financial Statements

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

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

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

David L. Hauser

David L. Hauser
Controller

Results of Operations

Earnings and Dividends

Earnings per share increased 27 percent from $2.21 in 1992 to $2.80 in 1993. The increase was primarily due to higher kilowatt-hour sales and a one-time charge taken in 1992 related to a rate refund to North Carolina retail customers of $.32 per share. (For additional information on the refund, see Liquidity and Resources, "Rate Matters," page 39.) The increase was partially offset by higher operating and maintenance expenses, additional charitable contributions to the Duke Power Company Foundation and an increase in the federal income tax rate caused by the Omnibus Budget Reconciliation Act of 1993. Higher general taxes also decreased earnings.

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

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

Revenues and Sales

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

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

Operating Expenses

From 1992 to 1993, non-fuel operating and maintenance expenses rose 4 percent. Administrative and general expenses increased partly because of increased pension expenses to reflect more conservative investment return assumptions and one-time costs associated with a voluntary separation option offered during the first quarter of 1993. A winter storm during the first quarter of 1993 also increased non-fuel operating and maintenance expenses. These increases from 1992 to 1993 were partially offset by lower nuclear and fossil maintenance expenses resulting from lower outage costs.

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

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

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

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

Other Income and Interest Deductions

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

The carrying charge, net of associated taxes, on the purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station represented 6 percent of total earnings in 1993, compared to 6 percent in 1992 and 5 percent in 1991. This carrying charge and the related tax benefits are included in Other, net and Income taxes — other, net, respectively. The growth in this carrying charge is due to the increasing cumulative impact of the Company's funding of purchased power costs which current rates are expected to collect in future periods. The Company recovers the accumulated balance, including the carrying charge, when the declining purchased capacity payments drop below the levelized revenues. (For additional information on purchased capacity levelization, see Capital Needs "Purchased Capacity Levelization," page 40.)

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

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

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

Liquidity and Resources

Rate Matters

During 1991, the Company filed in both the North Carolina and South Carolina retail jurisdictions its only requests for general rate increases since 1986. The rate increases were primarily needed to recover costs associated with the construction of the Bad Creek Hydroelectric Station. In North Carolina, the Company requested a 9.22 percent rate increase and was granted a 4.15 percent increase, which resulted in additional annual revenues of $100.1 million. In South Carolina, a 7.29 percent increase was requested and a 3.0 percent rate increase was granted, resulting in additional annual revenues of $30.2 million.

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

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

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

The other joint owners of the Catawba Nuclear Station and the Company are involved in various proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding is that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.) The Company and two of the four joint owners have entered into a proposed settlement agreement which, if approved by the regulators, will resolve all issues in contention in such proceedings between the Company and these owners. The Company recorded a liability as an increase to Other current liabilities on its Consolidated Balance Sheets of approximately $105 million in 1993 to reflect this proposed settlement. In addition, future estimated obligations in connection with the settlement are reflected in estimates of purchased capacity obligations in Note 3. As the Company expects the costs associated with this settlement will be recovered as part of the purchased capacity levelization, the Company has included approximately $105 million as an increase to Purchased capacity costs on its Consolidated Balance Sheets. Therefore, the Company believes the ultimate resolution of these matters should not have a material adverse effect on the results of operations or financial position of the Company.

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

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

Cash From Operations

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

Financing and Investing Activities

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

As a result of favorable market conditions, the Company continued refinancing activities to retire higher cost debt and preferred stock. During 1993, the Company obtained proceeds from the issuance of $1.5 billion in long-term debt and $220 million in preferred stock, most of which were used to retire $1.4 billion of long-term debt and $216 million of preferred stock.

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

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

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

Fixed Charges Coverage

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

Capital Needs

Property Additions and Retirements

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

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

Construction Expenditures

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

Projected construction and nuclear fuel costs, both including AFUDC, are $2.3 billion and $394 million, respectively, for 1994 through 1996. Total projected construction costs include expenditures for the construction of the Lincoln Combustion Turbine Station and replacement of certain steam generators at the McGuire Nuclear Station and the Catawba Nuclear Station. (For additional information on steam generator replacement, see Current Issues "Stress Corrosion Cracking," page 42.) For 1994 through 1996, the Company anticipates funding its projected construction and nuclear fuel costs through the internal generation of funds and, to a lesser extent, through the issuance of securities, primarily First and Refunding Mortgage Bonds.

Purchased Capacity Levelization

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

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

Meeting Future Power Needs

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

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

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

in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. As additional demand-side costs are incurred, the Company ultimately expects recovery of associated costs, which are currently being deferred, through rates. The annual costs deferred, including the return, were approximately $26 million in 1993 and $18 million in 1992.

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

Current Issues

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

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

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

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

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

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

The Clean Air Act Amendments of 1990. The Clean Air Act Amendments of 1990 require a two-phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national objective of clean air in the most cost-effective manner and has already reduced emissions through the use of low-sulfur coal in its fossil plants, through efficient operations and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. The Company is currently developing a detailed

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

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

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

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

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

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

Subsidiary Highlights

The earnings contribution of the Company's diversified activities and subsidiaries was $22.0 million in 1993, $25.7 million in 1992 and $23.6 million in 1991. (a) (b) Highlights of selected subsidiaries are presented below. (dollars in thousands)

Electric Power Supply

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

	1993	1992	1991
Assets net of liabilities	$ 47,679	$ 42,910	$ 39,384
Net income	$ 4,261	$ 3,526	$ 2,721
Number of employees (c)	194	191	194

Funds Management

Church Street Capital Corp. (CSCC) manages investment of funds for the Company and is the parent company of several subsidiaries. CSCC has no full-time employees.

	1993	1992	1991
Short-term investments and marketable securities	$155,871	$173,347	$120,303
Investment income (after tax)	$ 3,548	$ 5,404	$ 6,397

Highlights of CSCC's subsidiaries are presented below:

- **Real Estate Management, Land Development**

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

	1993	1992	1991
Assets net of liabilities	$133,034	$110,949	$ 88,046
Net income (a)	$ 16,327	$ 16,613	$ 9,661
Number of employees (c)	77	73	69

- **Engineering, Construction, Technical Services and Power Development**

  Engineering, construction, technical services and power development opportunities are pursued nationally and internationally.

  - Duke Engineering & Services, Inc. markets engineering, construction, quality assurance, consulting and other engineering-related services for utility facilities other than coal-fired plants.
  - Duke/Fluor Daniel, a joint venture with Fluor Daniel, Inc., provides design, construction, operation and maintenance support primarily for coal-fired generating plants.
  - Duke Energy Group, parent of Duke Energy Corp., structures, finances and manages investments in electric generation and transmission facilities.

	1993	1992	1991
Assets net of liabilities	$127,708	$ 36,687	$ 13,480
Net income	$ 40	$ 33	$ 1,512
Number of employees (c)	518	495	364

(a) 1991 excludes the cumulative effect of an accounting change of $6,727,000, after tax.
(b) The earnings contribution of the Company's subsidiaries and non-electric operations includes elimination of intercompany profit of $509,000 and $1,211,000, after tax, in 1993 and 1992, respectively.
(c) Full-time employees.

SELECTED FINANCIAL DATA

	1993	1992	1991	1990	1989
Condensed consolidated statements of income (thousands)					
Electric revenues (a)	**$ 4,281,876**	$ 3,961,484	$ 3,816,960	$ 3,705,131	$3,692,955
Electric expenses (a)	**3,467,811**	3,236,789	3,110,137	3,062,348	2,988,355
Electric operating income	**814,065**	724,695	706,823	642,783	704,600
Other income	**71,269**	85,007	150,905	146,740	101,826
Income before interest deductions	**885,334**	809,702	857,728	789,523	806,426
Interest deductions	**258,919**	301,619	274,105	251,335	234,815
Net income	**626,415**	508,083	583,623	538,188	571,611
Dividends on preferred and preference stock	**52,429**	56,407	54,683	52,616	52,477
Earnings for common stock	**$ 573,986**	$ 451,676	$ 528,940	$ 485,572	$ 519,134
Common stock data (b)					
Shares of common stock — year-end (thousands)	**204,859**	204,859	204,699	202,584	202,563
— average (thousands)	**204,859**	204,819	203,431	202,570	202,554
Per share of common stock					
Earnings	**$2.80**	$2.21	$2.60	$2.40	$2.56
Dividends	**$1.84**	$1.76	$1.68	$1.60	$1.52
Book value — year-end	**$21.17**	$20.26	$19.86	$18.84	$18.05
Market price — high-low	**$44⅞-35⅜**	$37½-31⅜	$35-26¾	$32⅜-25½	$28¼-21⅜
— year-end	**$42⅜**	$36⅛	$35	$30⅝	$28 1/16
Balance sheet data (thousands)					
Total assets	**$12,193,107**	$10,950,387	$10,470,615	$10,083,507	$9,542,398
Long-term debt	**$ 3,285,397**	$ 3,288,111	$ 3,159,575	$ 3,102,746	$2,822,442
Preferred stock with sinking fund requirements	**$ 281,000**	$ 279,519	$ 228,650	$ 239,800	$ 247,825
Electric and other statistics					
Kilowatt-hour sales (millions)					
Residential	**19,465**	17,789	17,918	17,221	16,895
General service	**16,904**	15,818	15,586	15,032	14,206
Industrial	**28,198**	27,041	26,270	25,894	25,934
Other energy and wholesale (a) (c)	**11,337**	10,360	10,132	10,468	11,969
Total kilowatt-hour sales billed	**75,904**	71,008	69,906	68,615	69,004
Unbilled kilowatt-hour sales	**154**	34	(19)	(540)	370
Total kilowatt-hour sales	**76,058**	71,042	69,887	68,075	69,374
Residential customer data					
Average annual KWH use	**13,372**	12,427	12,710	12,444	12,459
Average revenue billed per KWH	**7.32¢**	7.38¢	7.10¢	7.07¢	7.09¢
Sources of energy (millions of KWH) (d)					
Generated — Coal	**34,097**	28,999	26,455	27,262	26,175
— Nuclear (e)	**48,211**	48,238	49,328	44,649	47,773
— Hydro (f)	**1,582**	1,834	1,545	1,879	1,520
— Oil and gas	**43**	5	7	53	27
Total generation	**83,933**	79,076	77,335	73,843	75,495
Purchased power and net interchange (a)	**1,750**	1,403	587	1,531	1,158
Total output	**85,683**	80,479	77,922	75,374	76,653
Less: Other Catawba joint owners' share	**13,821**	14,313	12,280	11,735	12,566
Plus: Purchases from other Catawba joint owners	**8,810**	9,466	8,525	8,658	9,809
Total sources of energy	**80,672**	75,632	74,167	72,297	73,896
Line loss and Company usage	**4,614**	4,590	4,280	4,222	4,522
Total kilowatt-hour sales	**76,058**	71,042	69,887	68,075	69,374
System average heat rate	**9,921**	9,974	9,996	10,007	10,013
System load factor	**60.2%**	60.0%	59.4%	59.9%	61.8%

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

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

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

(d) Does not include operating statistics of Nantahala Power and Light Company.

(e) Includes 100% of Catawba generation.

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

Selected Financial Data

Quarterly Financial Data

Dollars in Thousands (except per-share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
1993 by quarter					
Electric Revenues	$1,007,783	$987,218	$1,289,994	$996,881	$4,281,876
Electric Operating Income	188,522	169,111	283,411	173,021	814,065
Net Income	141,684	122,470	241,409	120,852	626,415
Earnings Per Share	$0.63	$0.53	$1.12	$0.52	$2.80
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

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

Stock Market Information

The Company had 127,688 holders of record of common stock as of December 31, 1993, and 125,881 holders as of December 31, 1992. During 1993, approximately 50,262,200 shares of common stock were traded, compared with 57,340,600 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
1993 by quarter			
Fourth	$0.47	$44	$39
Third	0.47	44⅞	39⅞
Second	0.45	41⅜	37⅛
First	0.45	39⅞	35⅜

	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

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 Springs Industries, Inc. [4]

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

Joe T. Ford
Chairman and Chief Executive Officer Alltel Corporation [2]

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.
President, Domestic Consumer Division Blockbuster Entertainment Corp. [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 Corporation of North America [3,5,6]

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

Retiring Director

The following director has retired:

John L. Fraley
Chairman Emeritus Carolina Freight Corporation

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

THE MANAGEMENT COMMITTEE consists of members of the Board who are officers of the Company.

THE AUDIT COMMITTEE'S responsibilities include recommending an independent auditor for the Company, reviewing reports submitted by the auditor, examining procedures regarding Duke's internal audit program and making necessary recommendations to the Board as appropriate.

THE COMPENSATION COMMITTEE'S responsibilities include approving salaries and compensation of all officers and directors of Duke Power and making recommendations to the Board regarding the salary of the Chairman of the Board.

THE CORPORATE PERFORMANCE REVIEW COMMITTEE monitors the overall performance of the Company and makes recommendations for improvement. At the policy level, it determines the adequacy of and support for Duke Power's emphasis on continuous improvement.

THE FINANCE COMMITTEE directs Duke Power's financial and fiscal affairs and makes recommendations about dividend, financing and fiscal policies.

THE NOMINATING COMMITTEE makes recommendations to the Board regarding the size and composition of the Board of Directors and individuals for consideration as successors to the Chief Executive Officer, including those recommended by shareholders.

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 and Chief Planning Officer

Michael S. Tuckman
Senior Vice President, Nuclear Generation Department

James R. Bavis
Vice President, Human Resources

Sue A. Becht
Treasurer

Sharon A. Decker
Vice President, Customer Services

Excell O. Ferrell, III
Vice President, Northern Region

William L. Foust
President, Duke Merchandising

Ronald L. Gibson
Vice President, Marketing and Customer Planning

James E. Grogan
Vice President, Generation Services Department

James W. Hampton
Vice President, Oconee Nuclear Site

Donald E. Hatley
Vice President, Public Affairs

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, Winston-Salem Area

F. Alfred Jenkins
Vice President, Hickory Area

Robert S. Lilien
Vice President and Tax Counsel

John F. Lomax
Vice President, Southern Region

David H. Maner
Vice President, Greensboro Area

Maurice D. McIntosh
Vice President, Fossil and Hydro Generation Department

Ted C. McMeekin
Vice President, McGuire Nuclear Site

Barbara B. Orr
Vice President, Greenville Area

Richard J. Osborne
Vice President and Chief Financial Officer

David L. Rehn
Vice President, Catawba Nuclear Site

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

Ellen T. Ruff
Secretary and Deputy General Counsel

Ruth G. Shaw
Vice President, Corporate Communications

William R. Stimart
Vice President, Rates and Regulatory Affairs

Fred E. West, Jr.
Vice President, Central Region

Virginia M. Britton
Assistant Controller

Carolyn R. Duncan
Assistant Secretary

S. L. Love
Assistant Treasurer

Phyllis T. Simpson
Assistant Secretary

Principal Subsidiaries and Affiliates

William S. Lee
President
Church Street Capital Corp.

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

Richard C. Ranson
Chairman
Crescent Resources, Inc.

Clarence L. Ray, Jr.
President
Duke/Fluor Daniel

N. E. Tucker
President and Chairman of the Board
Nantahala Power and Light Co.

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

Retiring Officers

The following officers have retired:

Lewis F. Camp, Jr.
Secretary and Associate General Counsel

E. N. Hedgepeth, Jr.
President and Chairman of the Board
Nantahala Power and Light Co.

John P. O'Keefe, Jr.
Vice President, Taxes

Hal B. Tucker
Senior Vice President, Nuclear Generation Department

Investor Information

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

Annual meeting
The 1994 Annual Meeting of Duke Power Shareholders will be:
Date: Thursday, April 28, 1994
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.

Certain 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:

1993 Annual Report on Form 10-K as filed with the Securities and Exchange Commission

Statistical Supplement to the 1993 Annual Report to Shareholders

Audiotape recording of excerpts from the 1993 Annual Report to Shareholders

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

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 shareholders of record, Duke Power electric customers, Duke Power employees and other residents of North and South Carolina. This provides a convenient way to buy common shares without brokerage fees. A safekeeping option is available for depositing common stock in the Plan.

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.

Dividend payment
Duke Power has paid quarterly cash dividends on its common stock for 67 consecutive years.

Dividends on the Company's common and preferred stock in 1994 are expected to be paid on:

March 16, June 16, September 16 and December 16

Recycled
Recyclable

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

Bulk Rate
U.S. Postage
PAID
Charlotte, N.C.
Permit No. 3073