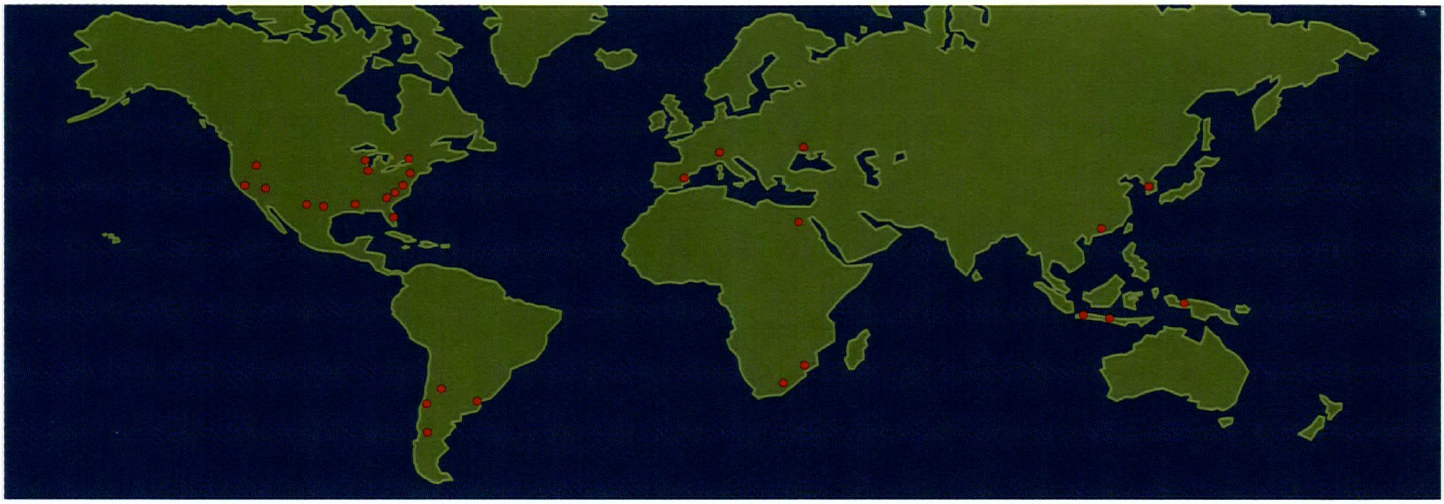
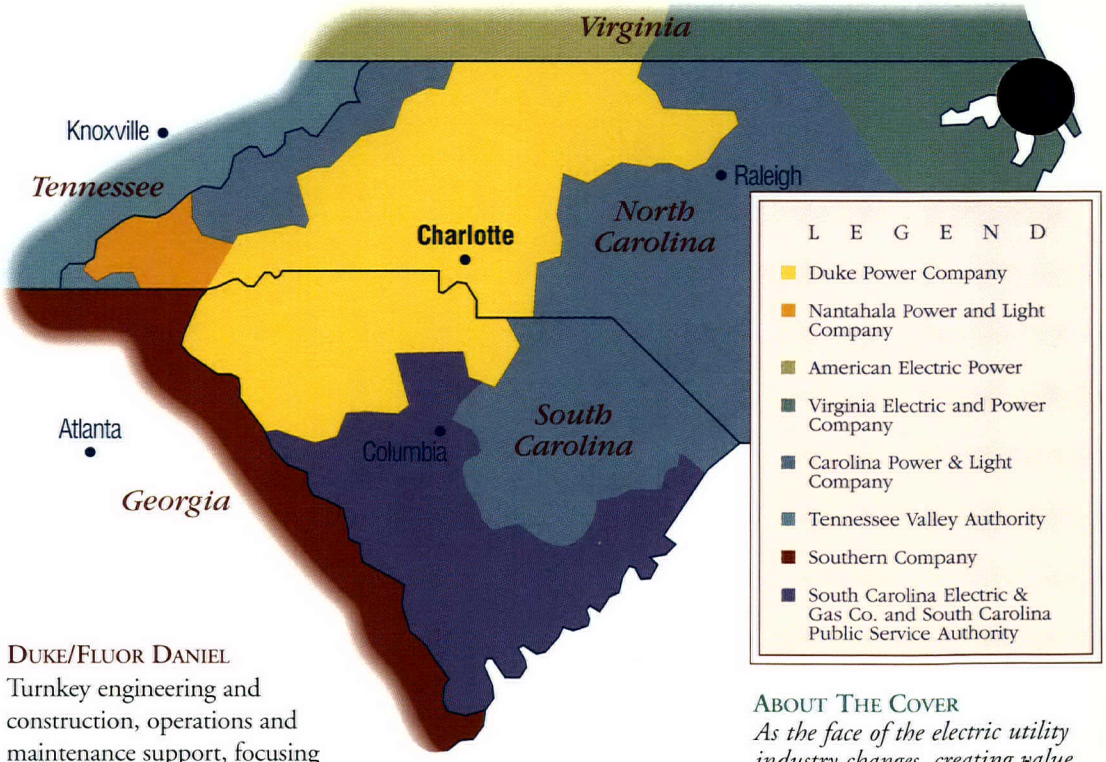
DUKE POWER COMPANY ❖ 1995 ANNUAL REPORT

Creating Value In A Changing Environment

About Duke Power Headquartered in Charlotte, N.C., Duke Power Company was founded 91 years ago and is one of the nation's largest investor-owned electric utilities. Duke Power and its subsidiary, Nantahala Power and Light Company, operate three nuclear generating stations, eight coal-fired stations, and 38 hydroelectric stations. Together, these units produced 89 billion kilowatt-hours of electricity in 1995. The Company's share of this generation totaled 75 billion ki hours. Total 1995 operating revenues, including those of the Associated Enterprises Group, were $4.7 billion.

The Company consists of 10 business units which, except for electric service provided within Duke's service area, are part of the Associated Enterprises Group. The business units within the Associated Enterprises Group are spreading Duke Power's name and reputation worldwide, as shown on the map below.





Business Units

Duke Power Company
Franchised electric service to approximately 1.8 million residential, general service, and industrial customers in a 20,000 square-mile service area in North Carolina and South Carolina

Church Street Capital Corp.
Investment management, equity funding, and credit enhancement for non-electric operating activities

Crescent Resources, Inc.
Real estate development and forest management

Duke Energy Group, Inc.
Development, ownership and operation of electric power facilities, and marketing of electric power and natural gas

Duke Engineering & Services, Inc.
Energy and environmental engineering, construction management, operations and maintenance, and consulting services

Duke/Fluor Daniel
Turnkey engineering and construction, operations and maintenance support, focusing on coal-fired plants

Duke Merchandising
Appliance and electronics sales and service

DukeNet Communications, Inc.
Development and management of communications systems

Duke Water Operations
Franchised water service for areas of North Carolina and South Carolina

Nantahala Power and Light Company
Franchised electric service for a five-county area in western North Carolina

About The Cover
As the face of the electric utility industry changes, creating value for Duke Power shareholders means striking an effective balance between the regulated and unregulated marketplace. Duke Power believes its s as a regulated supplier, with the broad range of services provided by its unregulated business units, will continue to enhance shareholders' investment in the years ahead.

Contents

Highlights Of The Year

Years Ended December 31,	1995	1994	Percent increase (decrease)
Kilowatt-hour sales (millions) (a)	76,737	75,563	1.6
Electric revenues (a)	$4,422,438,000	$4,279,329,000	3.3
Operating revenues	$4,676,684,000	$4,488,913,000	4.2
Earnings for common stock	$ 665,635,000	$ 589,152,000	13.0
Common stock data			
Average shares outstanding	204,859,000	204,859,000	—
Earnings per share	$3.25	$2.88	12.8
Dividends per share	$2.00	$1.92	4.2
Book value per share (year-end)	$23.36	$22.13	5.6
Market value per share (year-end)	$47⅜	$38⅛	24.1
Return on average common equity	14.3%	13.3%	7.5
Plant construction costs (including AFUDC) (b)	$ 583,128,000	$ 650,341,000	(10.3)
Nuclear fuel construction costs (including AFUDC)	$ 89,358,000	$ 128,584,000	(30.5)
Internal cash generation	81%	67%	19.4
Earnings coverage of fixed charges, SEC method	4.94X	4.72X	4.7
Total electric plant, net (a)	$9,248,613,000	$9,166,300,000	.9
Peak load (KW) (a) (c)			
Summer	15,542,000	14,150,000	9.8
Winter	14,382,000	15,284,000	(5.9)
Full-time employees at year-end (d) (e) (f)	17,121	17,052	.2

(a) Nantahala Power and Light Company operations.
(b) Excludes Nantahala Power and Light Company and Duke Power's other subsidiaries.
(c) Excludes the portion of the demand of the other joint owners of the Catawba Nuclear Station met by their retained ownership.
(d) Includes 1,355 and 1,011 full-time employees of diversified businesses for 1995 and 1994, respectively.
(e) Includes 1,798 and 1,898 employees for 1995 and 1994, respectively, at the Catawba Nuclear Station, of which the Company owns 12.5 percent.
(f) 1995 includes certain employees who have accepted the Company's enhanced vested retirement benefit program.

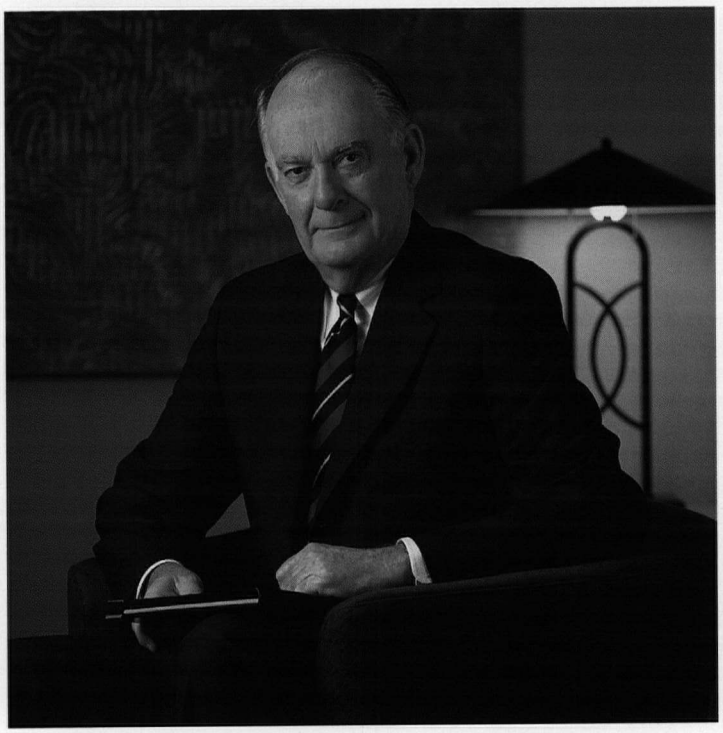
TO OUR SHAREHOLDERS:

These two quotes are gratifying and illuminating to anyone with an interest in Duke Power Company and the electric utility industry. Gratifying because it is always pleasing to have independent endorsement of your company. Illuminating because they show how quickly the industry is changing.

Ten years ago, continued viability of nuclear power was the central issue facing the industry. Environmental and safety concerns, eroding public support, and high construction costs raised the question of whether new plants could be built and operated economically.

"If any utility was equipped to cope with the challenge of the nuclear age, that utility was North Carolina's Duke Power Co."

FORBES, *February 11, 1985*



As *Forbes* says, the industry now finds itself in a new era of competition with challenges equally daunting.

The challenge for any investor-owned utility is not only adapting to this new era, but ensuring that the value of its shareholders' investment continues to be enhanced. At Duke Power, we believe we are meeting both challenges. In this year's annual report, we will explain why.

EARNINGS PER SHARE GROW TO $3.25

Our financial results indicate 1995 was an excellent year as earnings per share increased 12.8 percent to $3.25 on total revenues of $4.7 billion. Kilowatt-hour sales, excluding Nantahala Power and Light Company operations, rose 1.6 percent.

The Company's quarterly dividend was raised two cents to 51 cents per share in the third quarter, increasing the indicated annual dividend to $2.04 per share. Dividends have been increased annually since 1976, and over the last three years the average annual compounded growth rate for dividends has been 4 percent.

ELECTRIC OPERATIONS

Although income from diversified operations continues to be of increasing importance, Duke Power derives the bulk of its earnings from its electric operations, head President and Chief Operating Officer Rick Priory. Electric revenues of $4.4 billion for 1995, excluding Nantahala Power and Light operations, were up 3.3 percent

compared to 1994. Total kilowatt-hour (kwh) sales for 1995 increased to 76.7 billion kwh from 75.6 billion kwh in 1994.

The biggest contributor to the increase in revenue was weather. Hotter summer weather and colder winter weather in 1995 helped boost residential sales 4.2 percent. General service or commercial sales rose 5.0 percent and industrial sales increased 1.7 percent. Textile sales fell 1.1 percent, but other industrial sales rose 3.7 percent. Wholesale sales decreased 19.4 percent, primarily due to a decrease of 36.4 percent in supplemental sales to the other joint owners of the Catawba Nuclear Station.

The amount of capacity the Company was obligated to purchase from the other joint owners of the Catawba Nuclear Station declined significantly in 1995 as reflected in the supplemental sales decrease discussed above. As a result, the presentation of certain statistical information has been restated to reflect our 12.5 percent ownership. This restatement impacts statistical information only since we have historically presented costs reflecting our 12.5 percent ownership. With additional significant declines in these obligations in 1996, cash flows should continue to remain strong.

Our nuclear system operated at 90 percent of capacity during the year, its best year ever. Collectively, the nuclear units provided 54 percent of the electricity Duke generated in 1995. Since the Company's first nuclear generator went on-line in 1973 at the Oconee Nuclear Station, Duke Power's nuclear system has proven itself to be a safe, reliable, cost-effective, and environmentally friendly source of base-load generation.

Duke's coal-fired system also continues to operate exceedingly well. The system was again cited by *Electric Light & Power* magazine as being the most efficient in the country for 1994, measured by heat rate, a position Duke has held for 21 years. The coal-fired system's availability factor – the percentage of time a plant is available to generate power – was 87 percent in 1995. The Company's goal is to have at least 90 percent of coal-fired capacity available at all times, allowing the Company greater flexibility in making off-system sales.

At year-end, 12 of the 16 scheduled units at the Lincoln Combustion Turbine facility in Lincoln County, N.C., were in commercial service, with the last four scheduled for completion and commercial operation in early 1996. During the summer, six units were operating commercially and contributed to meeting the Company's record peak demand of 15,542 megawatts.

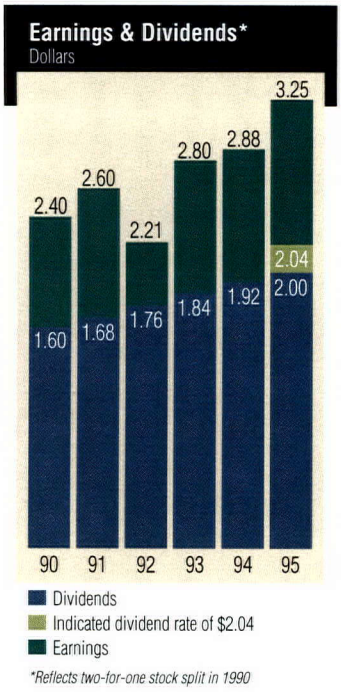
"Public utilities are struggling to adapt to the new era of competition. Duke is light-years ahead of all but a handful."

FORBES, *April 10, 1995*

AEG OPERATIONS

The nine business units within Duke Power's Associated Enterprises Group (AEG) contributed $54.3 million in earnings to the parent company in 1995, a 4.3 percent increase over 1994. The units, headed by AEG President Bill Coley, consist of all the Company's diversified businesses, including Nantahala Power and Light Company, a regulated utility serving about 53,000 customers in western North Carolina.

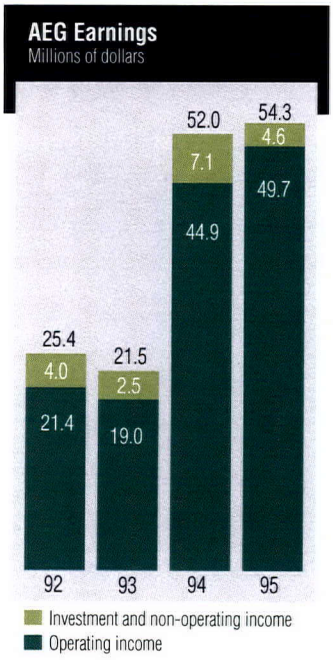
AEG's goal is to significantly increase its contribution to total company earnings over the next several years. Duke Power is looking to its AEG units as a prime source for added shareholder value. Besides Nantahala, AEG consists of Church Street Capital Corp., Cre Resources, Inc., Duke Energy Group, Inc., Duke Engineering & Services, Inc., Duke/Fl Daniel, Duke Merchandising, DukeNet Communications, Inc., and Duke Water Operations.



Together, the AEG units are seeking business opportunities within the United States and internationally. Duke Energy Group, Duke Engineering & Services, and Duke/Fluor Daniel all have international projects in locations ranging from South America to the Far East. Domestically, Duke Energy's power marketing venture with Louis Dreyfus Electric Power won the competition for a 10 1/2-year contract with the City of Dover, Delaware, following a 12-month evaluation that drew 22 proposals from utilities, independent generators and power marketers. Under the contract, Duke Energy and Louis Dreyfus collectively will be responsible for managing the operation and maintenance of Dover's existing electric generation. They will also buy low-cost energy from regional utilities through their affiliated companies to meet Dover's electricity needs.

Duke Engineering & Services enjoyed its most successful year ever, completing the acquisition of INTERA, Inc., an environmental services company, which broadens both its market reach and depth of client services.

Crescent Resources had another record year, experiencing continued strong demand in all sectors of its operations and in real estate development in particular. Crescent's earni increased 34 percent over 1994.



The BellSouth Carolinas PCS partnership, in which DukeNet Communications is a 20 percent owner, successfully bid for the right to provide Personal Communications Services (PCS) in the Charlotte Metropolitan Trading Area, which covers both Carolinas and a portion of Georgia.

Nantahala Power and Light Company's customer base grew by 3 percent and kilowatt-hour sales grew by 5 percent in 1995. The customer service offices in Franklin and Sylva moved to larger locations to better serve customers in these growing areas. The company also met the challenge imposed by Hurricane Opal, which was the most physically damaging storm in Nantahala's 66-year history. Repair crews replaced nearly twice as many poles as were damaged in the blizzard of 1993, which held the previous record for storm damage.

Duke Merchandising opened ten new stores in cities throughout the service area. These stores serve as a valuable point of contact with many Duke customers. Merchandising sales were up 14 percent over 1994, reflecting in part the greater visibility and easier customer access that the new stores offer consumers.

Duke Power's efforts in expanding non-utility business opportunities were recogniz *Electrical World* in November, when Duke was one of five recipients of the magazine's 19 James H. McGraw Awards. The publication cited Duke's "strategic and ground-breaking efforts to align utility and non-utility activities with the competitive market."

Creating Value in a Changing Environment

Pleased as we are about the Company's performance in 1995, we can never lose sight of the fact our industry is undergoing transition from a highly regulated monopoly to a diverse marketplace that includes highly competitive unregulated businesses as well as strictly regulated businesses. Duke Power and all other utilities must reconsider how they conduct their business to ensure that the value of each shareholder's investment is enhanced in the years ahead.

The challenges presented in this changing environment make it an exciting time for us. We are already seeing the first wave of industry consolidation through mergers and acquisitions; several major deals were announced in 1995 alone, and we may see more in 1996. While Duke Power fully intends to be alert to opportunities to grow through consolidation, be assured the Company will consider mergers and acquisitions only when shareholder value is enhanced over the long term.

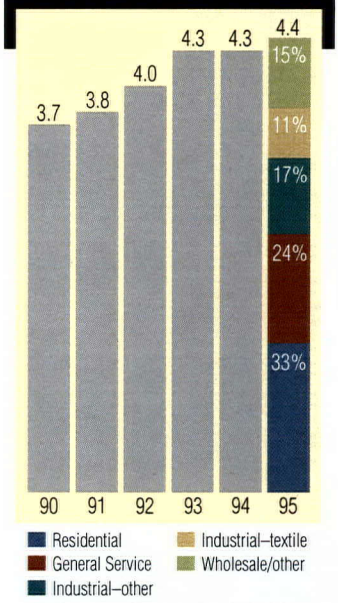
At the wholesale level, market competition is already a reality. In December the Federal Energy Regulatory Commission approved the Company's application to sell power at market-based rates. Power marketing, in which electricity is bought and sold as a commodity, is a young but clearly growing business. Duke Power will utilize these tools to increase the value of its own assets and procure capacity and energy for its customers on the best possible terms. Duke/Louis Dreyfus plans to be a leader in making markets in electricity and natural gas throughout North America.

We believe some degree of competition at the retail level is both desirable and inevitable, but a number of hurdles must be cleared to make it a reality. Fairness and equity in the marketplace, legislative and regulatory parity among suppliers, the equitable spreading of societal costs, reliability of power supply, recovery of stranded investments, proper placement of the obligation to serve – all are issues that must be resolved before competition at the retail level can be successful.

Regardless of the specific solution, it is clear the electric utility of the future will be vastly different from today's. Traditionally, the industry has been vertically integrated, with regulated utilities controlling the entire process from generation to delivery to the end user. Today, in response to changed economic and regulatory conditions, the idea of disaggregation – separating the parts of the integrated utility – is being considered by some utilities. This ultimately could result in separate generating, transmission, and distribution entities as companies sell or spin off entire businesses or discrete assets. Someday, instead of exclusively generating power for their own end-use customers, power producers may sell into a competitive market, using prices that change as frequently as every 30 minutes. Pooling of supply is already a reality in England, Scandinavia, and parts of South America, and the concept is under consideration in several states in the U.S., including notably California.

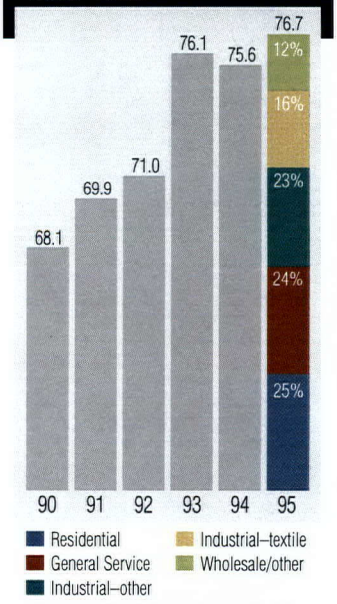
Changes such as these were unheard of just a few years ago. We at Duke Power are hard at work to determine how we will deal with these new issues. We are fortunate that we operate from

Duke Power Electric Revenues* Billions of dollars



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

Duke Power Kilowatt-Hour Sales* Billions

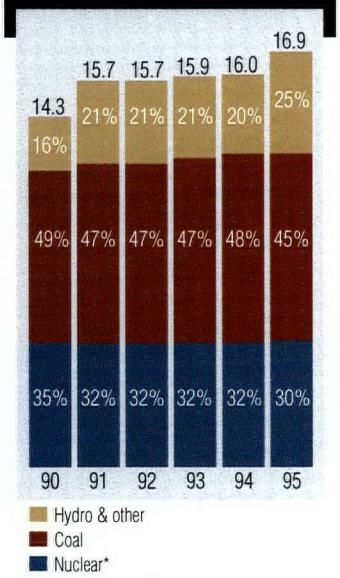


*1990 restated to reflect reclassification of certain power transactions previously classified as net interchange and purchased power, prior to a 1990 FERC order.

a position of strength, which offers us advantages many electric companies don't possess:

- We have designed, built, and operated a system of superbly efficient generating plants, capable of effectively competing in our region.
- We have a strong customer focus, which begins with the finest centralized customer service systems in the electric industry for serving residential customers, and continues through to teams of national account managers and line executives who focus specifically on each of our largest customers.
- We have a strong transmission grid, capable of reliably supplying our customers and connecting us with a diverse array of sources and potential markets.
- We have financial strength, reflecting conservative management of our balance sheet and a record of steady growth.
- We have a group of affiliate companies that together offer an extremely broad range of services to purchasers of electricity, and we are poised to expand those services as our industry enters into a new era.
- Finally, and most importantly, we have a team of employees possessing skills and leadership abilities to a depth and breadth unparalleled in our industry. This team is committed to the proposition that the inevitable change of our industry into a more competitive mode can benefit both the customer and the shareholder.

Duke Power Generating Capacity Millions of KW

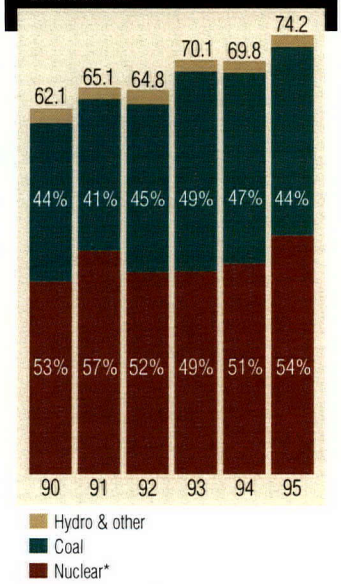


** Includes 12.5% of Catawba generation.*

As complex as the issues facing the industry are, we are confident they will be resolved. We intend to be an active player in that process. While there is no doubt that change will continue in the years ahead, shareholders can be confident that Duke Power is committed to creating additional value for their investment.

In the pages that follow, we will describe in more detail the objectives and strategies we have in place to help us meet our goal of creating value, and we will review the critical success factors by which we measure our progress. We have confidence in our direction and hope that, after reading this year's report, you will share our confidence.

Duke Power Net Generation** Billions of KWH



**Includes 12.5% of Catawba generation.*
***Excludes interchange power with the other joint owners of the Catawba Nuclear Station.*

Sincerely,

W. H. Grigg
Chairman and Chief Executive Officer
February 9, 1996

Creating Value In A Changing Environment

The electric utility industry is transforming from a group of franchised monopolies to a more competitive industry. The Energy Policy Act of 1992, and a number of initiatives by the Federal Energy Regulatory Commission, have introduced active competition at the wholesale level. On the retail side, industrial customers, eager to pare operating costs wherever possible, are seeking concessions and evaluating other supply options. Low-cost utilities with excess capacity are eyeing new markets outside their traditional franchises. Power marketers are eager to enter the business. And although retail competition is not currently allowed in North Carolina and South Carolina, regulators in some 40 states have at least begun to study the issues surrounding retail competition. As a result, competitive pressures are growing in all segments of the business.

For investors, the age of competition may be a time of uneasiness as they wonder whether the days of stable returns and steady, predictable dividend increases are gone. How well can a particular utility adapt to a more competitive environment? How can the utility continue to operate successfully during a transition period in which there is uncertainty regarding regulations and competitive forces? How does it intend not only to maintain but to enhance the value of its shareholders' investment?

These questions have been priorities for Duke Power for some time. As a result, the Company continues to focus on succeeding in a competitive marketplace and the long-term creation of value for Duke shareholders. Duke intends to accomplish the following:

- Achieve returns in the top quartile of the Standard & Poor's electric utilities index.
- Significantly increase earnings of the Company's diversified businesses.
- Maintain a strong credit rating.
- Achieve a high level of high customer satisfaction.

The Keys To Success

Duke Power has taken the steps necessary to foster success as a national energy services company.

In many ways, the Company is already realizing success in achieving the objectives it has set for itself. Duke is a low-cost supplier of energy. The Company's average price per kilowatt-hour is competitive on a local, regional, and national basis. Duke's coal-fired plants have led the nation in efficiency for more than two decades. The Lincoln Combustion Turbine facility is projected to be completed in 1996 under budget and 3 months ahead of schedule.

After Lincoln, the next increment of generating capacity is being acquired through competitive bidding. Competitive bidding allows the Company to evaluate alternatives available in a competitive marketplace, such as purchased-power call options or purchased-power contracts. These alternatives will be used if they result in a lower overall cost than Duke's traditional approach of designing, building, and owning additional new capacity. Taken together, Duke's ability to purchase power, build new capacity, or use a combination of the two will result in lower overall energy costs for our customers' future power needs.

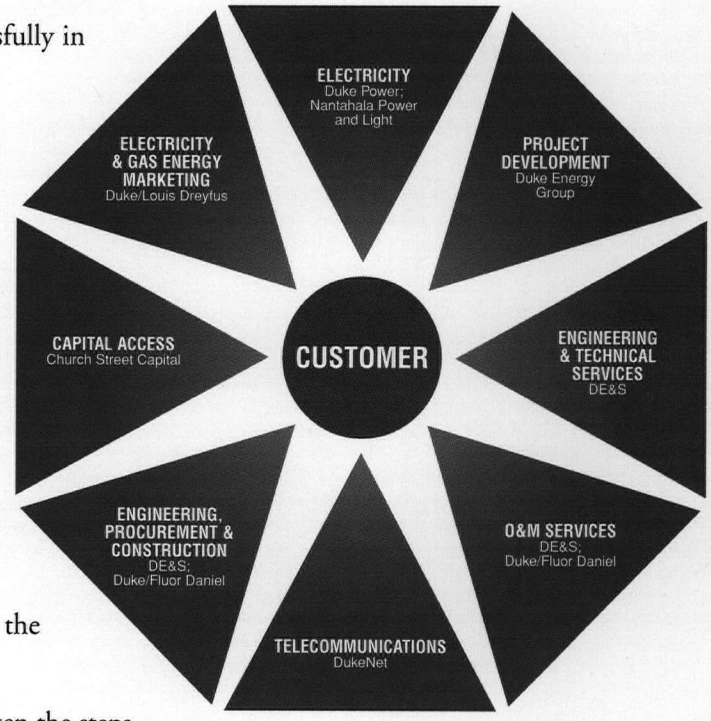
Meanwhile, Duke Power is uniquely positioned to capitalize on its existing expertise in designing, building, and operating generating facilities. Duke is one of only a few domestic utilities that has historically designed, built, and operated its own power plants. The expertise Duke gained in those areas over the years has been retained through Duke Engineering & Services, Inc. (DE&S) and Duke/Fluor Daniel, both business units within the Associated Enterprises Group (AEG).

AEG also enables Duke Power to take greater advantage of new business opportunities both in the U.S. and offshore. Much of Duke Energy Group's international business involves power projects in South America, while DE&S has ongoing projects throughout the world. Duke Energy's participation in a 370-megawatt gas-fired Chilean project will enhance future earnings and expand Duke's knowledge of one of the most advanced combined-cycle technologies available today.

Through Duke Energy's partnership with Louis Dreyfus Electric Power, one of the largest power marketers in the United States, Duke Power is positioning itself to become a major participant in the new power marketing business. In another partnership, Duke Energy is examining the possibility of taking over energy production at eight Hoechst Celanese Corporation facilities in the southeastern United States, freeing that company to concentrate more on its textile business and less on energy management issues.

DE&S's acquisition of INTERA, Inc., a well-established environmental company, builds globally on Duke Power's historical expertise in environmental protection and restoration and enhances the ability of DE&S to operate successfully in this fast growing market.

Early in 1996, Duke/Fluor Daniel completed a new base-load plant for South Carolina Electric & Gas Co., and announced in 1995 it will participate in a power plant construction project in Indonesia. Crescent Resources has transformed itself from a company focusing solely on timber and land management into a very successful commercial and residential real estate development firm with projects both inside and outside Duke Power's service area. DukeNet Communications, although still less than two years old, has [illegible] potential as a provider of fiber optic network connections and personal communications services within the Carolinas and the southeastern United States.



These and other projects clearly indicate Duke Power has taken the steps necessary to foster success as a national energy services company. However, there is still much to do. The next section of this report will focus on Duke's critical success factors – those areas in which the Company believes it must excel if it is to be successful in the years ahead.

Duke is well positioned to exploit the emerging opportunity for delivering total energy solutions to customers.

Measuring Success: The Critical Factors

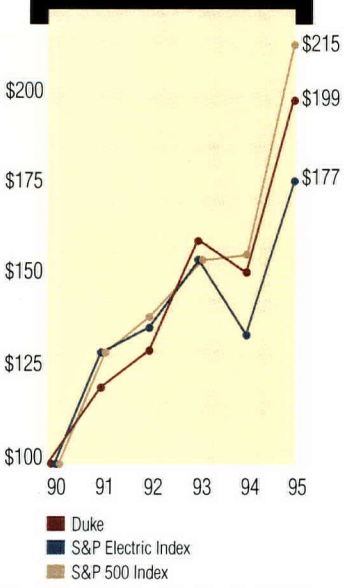
In its 1994 Annual Report, the Company introduced shareholders to several critical success factors, the measures Duke considers the key corporate indicators of success. Critical success factors provide a report card on the progress the Company is making in meeting the objectives outlined earlier in this report.

The next several pages highlight Duke's performance in 1995 against the critical success factors of Financial Performance, Growth and Market Share, Nuclear Excellence, and Customer Service and Satisfaction.

Over the last three years, Duke shareholders have realized a total average annual return of 14.8 percent.

Competition is changing the face of the electric utility industry. While electricity will always be generated at power plants and delivered through transmission lines, in the future electricity will more likely be a commodity bought and sold by buyers and sellers across the country. Trading rooms like the one at right at Duke/Louis Dreyfus in Wilton, Connecticut, will be the focal points of these transactions. Duke Energy Group and Louis Dreyfus are partners in Duke/Louis Dreyfus, which plans to be a leader in making markets in electricity and natural gas throughout North America.

Cumulative Total Return
Among Duke Power Company, S&P 500 Index, and S&P Electric Index



Assumes $100 invested on December 31, 1990 in Duke Power common stock, S&P 500 Index, and S&P Electric Utility Index. Assumes reinvestment of dividends.

FINANCIAL PERFORMANCE

In measuring financial performance, Duke Power focuses on three primary measures: a total return to shareholders in the top quartile of the Standard & Poor's (S&P) index of electric utilities, based on a three-year rolling average; maintenance of the Company's credit rating on its debt securities; and significantly increased contributions to total net income from business units within the Associated Enterprises Group (AEG).

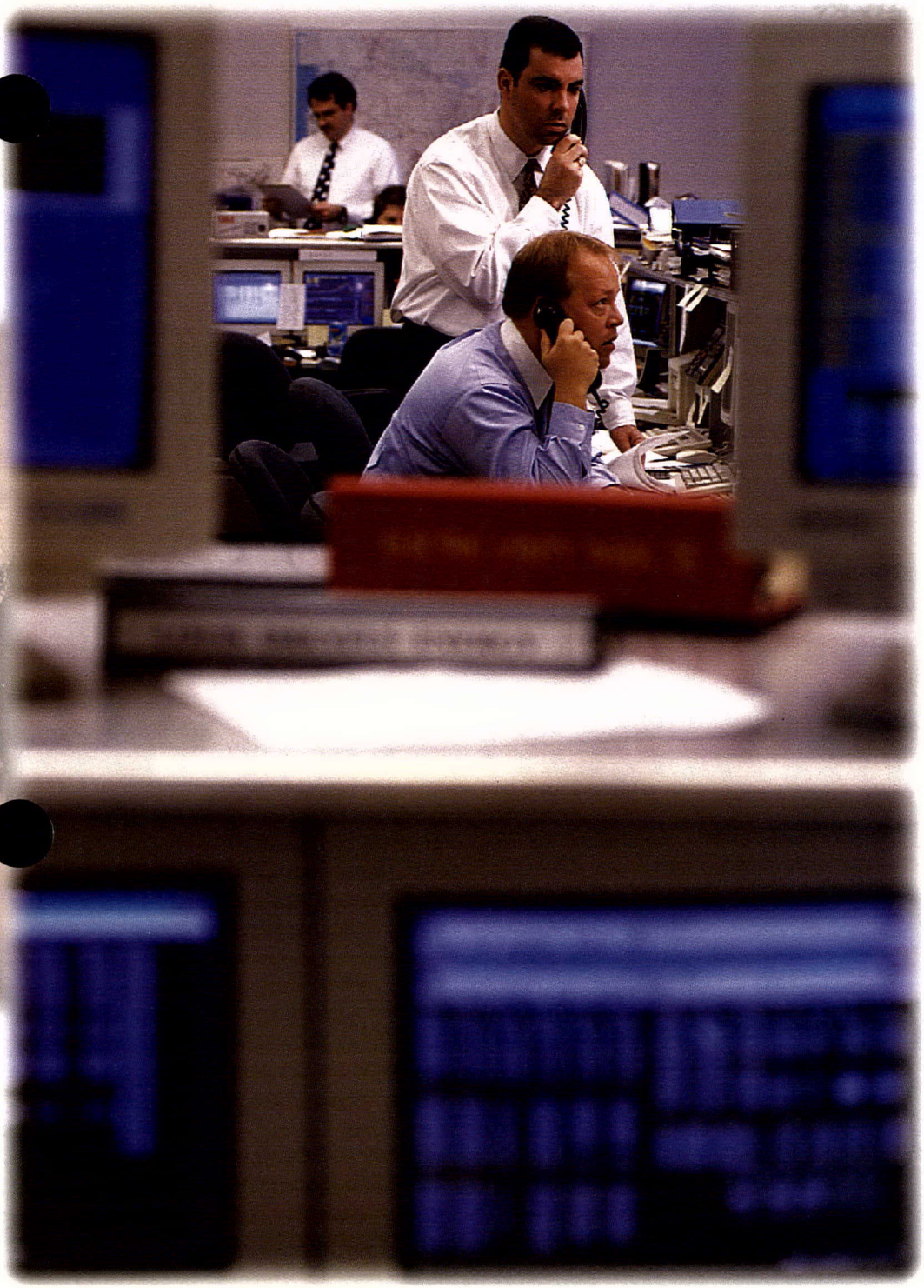
The Company believes that successful performance on these measures will provide a solid foundation for enhancing shareholder value.

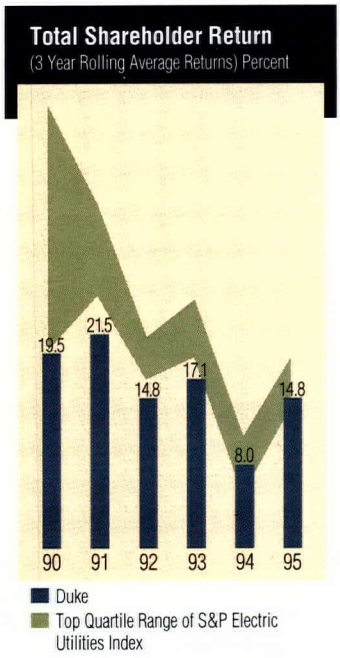
For the three years ended in December 1995, Duke shareholders realized a total average annual return of 14.8 percent, placing Duke second in the S&P electric utilities index. For comparison, the total return for the electric utilities index itself was 8.7 percent. The total return for the S&P 500 index was 15.3 percent.

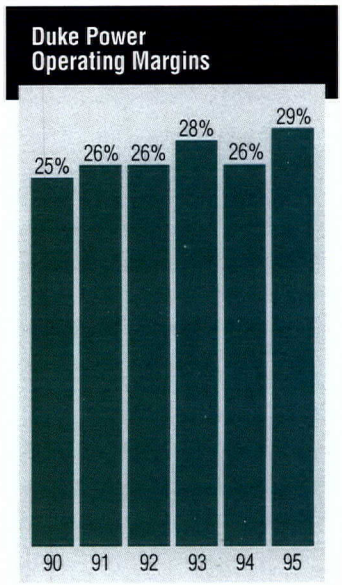
Another important measure is the Company's current double-A bond rating, which Duke maintained in 1995. A high rating ensures the Company's access to capital markets and, over time, helps lower capital costs.

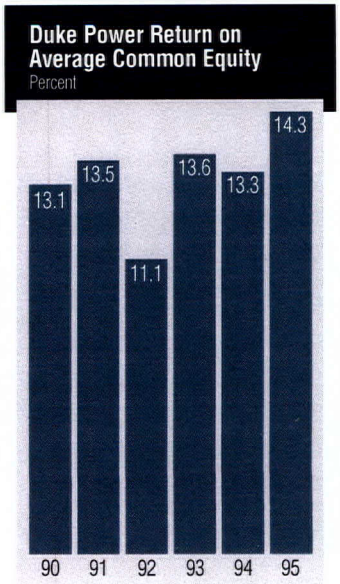
Securities Ratings

Rating Agency	Bonds	Preferred Stock	Commercial Paper
Duff & Phelps	AA-	A+	D-1+
Fitch	AA	AA-	[illegible]
Moody's	Aa2	aa2	P-1
S&P	AA-	A+	A-1+





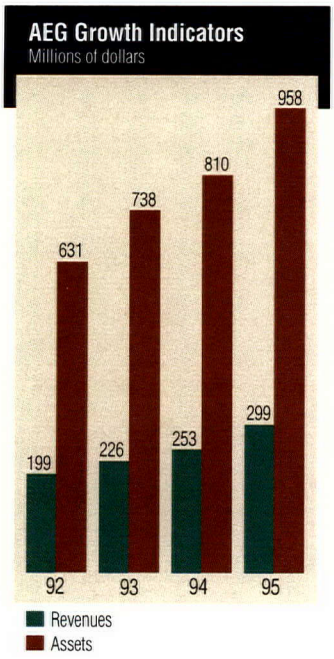




With growth in Duke's core electric business slowing, the business units within AEG are a key to adding increased value to a shareholder's investment. AEG's contribution to net income is expected to grow in significance over the next several years. In 1995, the AEG units added a total of $54.3 million to Duke's bottom line, up 4.3 percent from 1994. Net income in 1995 from AEG operating units was $49.7 million, compared to $44.9 million in 1994.

All AEG business units other than DukeNet Communications operated profitably in [illegible] The loss at DukeNet in 1995 stemmed primarily from investments associated with its participation with BellSouth and others in the development of a personal communications network, a new wireless communications technology that will be offered to the 10.4 million residents of the two Carolinas beginning in 1996. Long term, however, DukeNet Communications is expected to contribute to future shareholder value.

GROWTH & MARKET SHARE



In measuring success in expanding its business, Duke Power focuses on two key areas: retaining existing markets and increasing its share of selected markets. The Company seeks to expand its customer base by acquiring additional electric properties when an opportunity to create or enhance shareholder value exists.

Competition is changing the markets served by traditional electric utilities, compelling every utility to work harder to retain existing customers. Slow growth in domestic energy demand is forcing utilities to seek other business opportunities. Although growth in the Company's service territory is good relative to the industry, Duke expects to grow even more by taking advantage of opportunities to sell available capacity and energy to the wholesale market and by providing a superior level of service and customer commitment that will attract new customers both within and outside the Company's service area.

Through its AEG business units, Duke is already capable of providing a full range of energy services worldwide, whether a client's needs involve selling assets, design-and-build services, management and operating expertise, or any combination of the three. In addition, AEG gives Duke Power greater flexibility to take advantage of changing market conditions. Duke Energy, for example, has investments in Indonesia and South America where growth in demand exceeds that of the United States. Duke/Louis Dreyfus, Duke Energy Group's partnership with Louis Dreyfus Electric Power, began operations in late 1995 to take advantage

[illegible]ther it's energy projects like [illegible] Energy Group's Piedra del [illegible]a project in Argentina, power plant construction projects like the Cope Generation Station Duke/Fluor Daniel built for South Carolina Electric & Gas Co., or quality real estate developments such as Crescent Resources' Ballantyne country club development near Charlotte, N.C., Duke Power's business units are expanding Duke Power's name and reputation to markets worldwide.

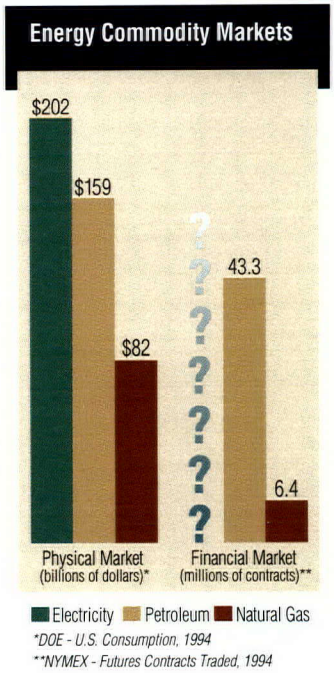
of anticipated growth in domestic energy services. Besides offering the potential for additional income, Duke/Louis Dreyfus affords opportunities for Duke Power to gain experience and expertise in making markets in electricity and natural gas.

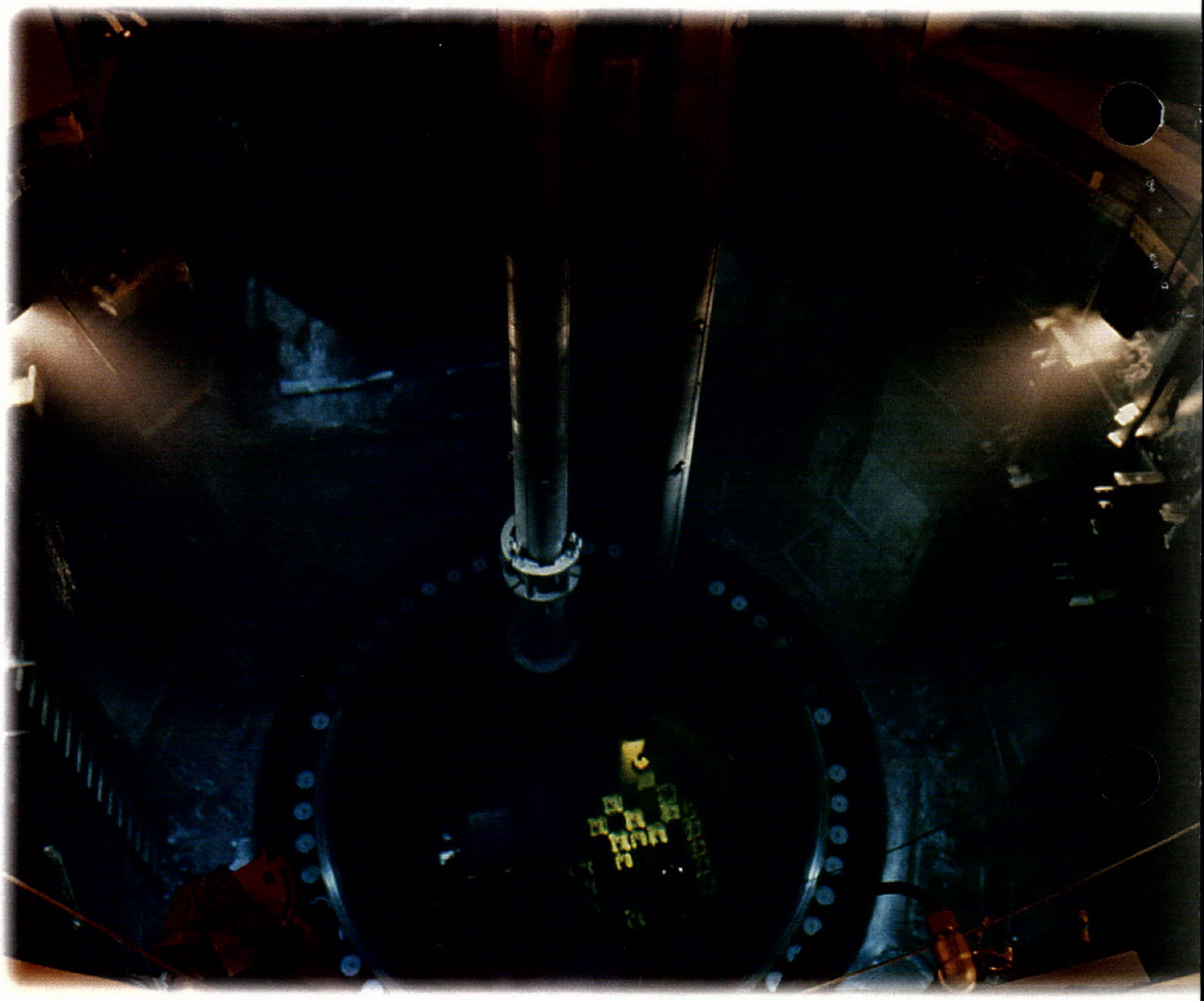
Crescent Resources and DukeNet Communications, two other AEG business units, are building markets outside the core electric business. Crescent, originally created to manage Duke's non-utility land and forestry operations, has experienced great success with residential and commercial developments both inside and outside of Duke's service area, including investments in real estate near Atlanta, Georgia, and Nashville, Tennessee. DukeNet is concentrating on providing high-capacity, current technology communications networks for private developers, long-distance carriers, and individual personal communications customers.

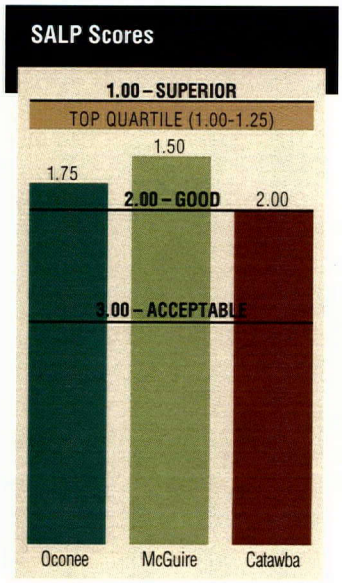
In the traditional franchised electric utility industry, a mature domestic market generally limits future growth to building an increased share of existing markets. For Duke Power, this means increased emphasis on expanding its share of the residential space heating and water heating markets, selling new processes made possible by electrotechnologies to aid industrial and commercial customers' needs, and targeting high-load industrial customers.

Restructuring of the domestic industry offers opportunities beyond traditional boundaries. The goal of increasing market share in a slow-growth environment raises the question of whether [illegible] Power will choose to acquire other utility assets or merge with other utilities. Duke is in an excellent position to make strategic acquisitions of other electric companies and/or specific electric assets such as generation, transmission, and distribution systems. The Company may pursue such opportunities if increased shareholder value would result over the long term.

Energy consumption plays a vital role in the U.S. economy. The Financial Market allows buyers and sellers to manage price uncertainty by hedging commodity price risk, providing price discovery, and enhancing market liquidity. The trading of electricity futures will begin in 1996.







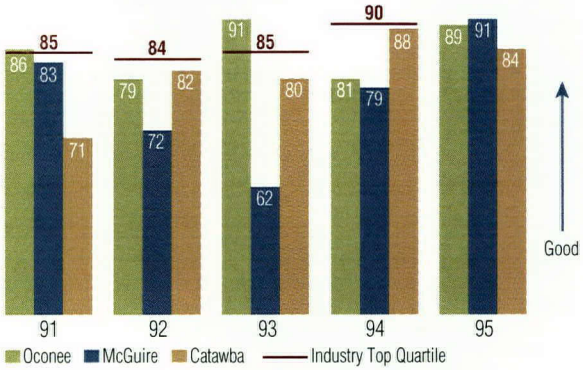
NUCLEAR EXCELLENCE

The continued safe, reliable operation of the Catawba, McGuire, and Oconee nuclear stations is critical to Duke's future success since most of our total generation is provided by nuclear energy. The Company measures its performance in this area through the Nuclear Regulatory Commission's (NRC) Systematic Assessment of Licensee Performance (SALP) evaluation, by the Institute of Nuclear Power Operations (INPO) evaluations, and by capacity factor, which measures a plant's actual production against its potential.

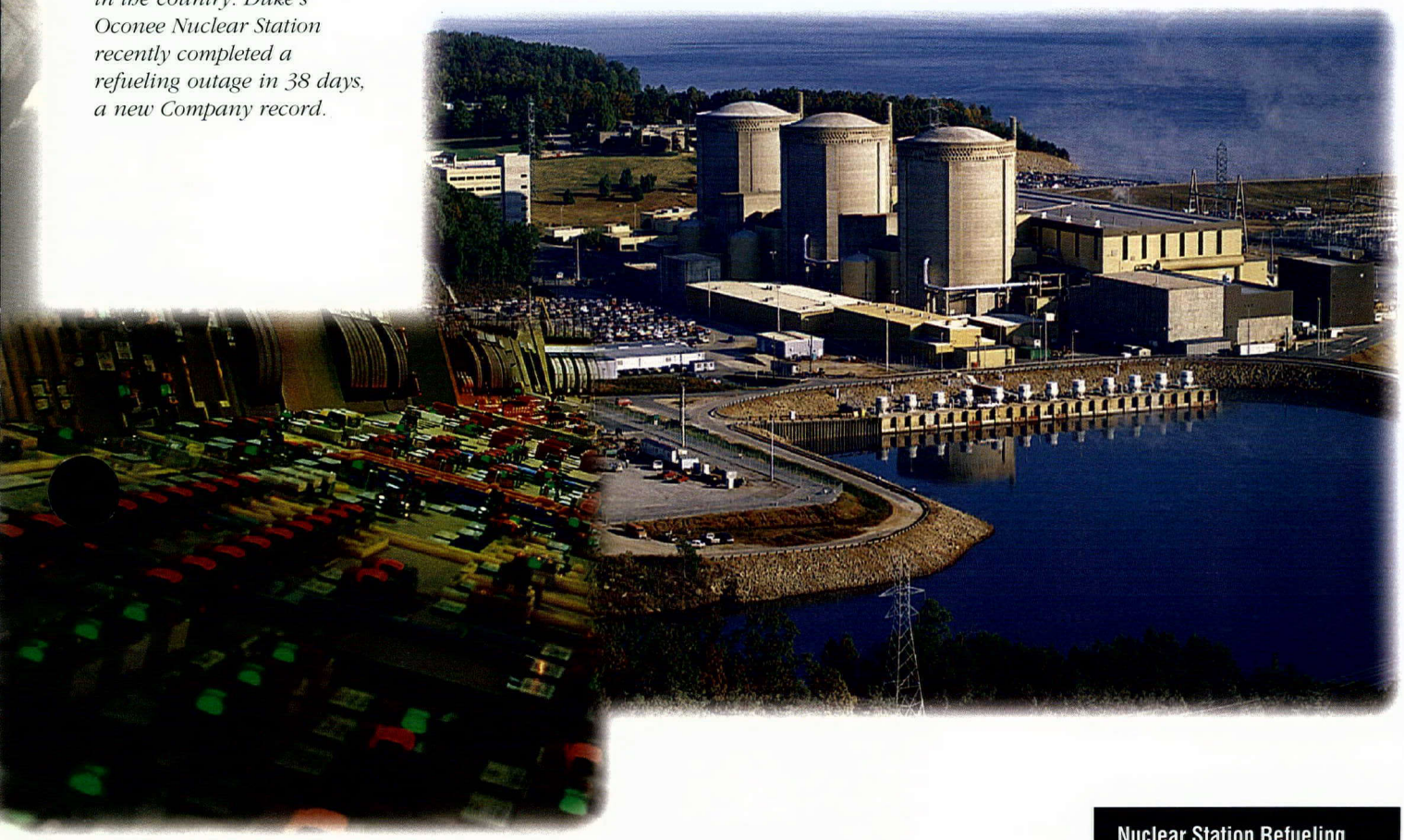
SALP reports issued by the NRC assess the regulatory performance of each station in four categories: operations, maintenance, engineering, and plant support. INPO evaluations cover operations, maintenance, training, chemistry, radiation protection, engineering support, organization, and administration. Duke's goal is for each station to be in the top 25 percent nationwide for both evaluations. Although we have made significant strides and our current reports indicate we are doing a good job, we have not yet achieved top quartile performance for all of the stations. We are working diligently to improve performance in all categories.

Duke also aims for each station to be in the top 25 percent of the industry in capacity factor. In 1995, Duke's nuclear capacity factors were 91 percent at McGuire Nuclear Station,

Nuclear Generation Capacity Factors Percent



Duke Power has owned and operated nuclear generating systems safely and reliably since 1973 and today operates the second-largest commercial nuclear system in the country. Duke's Oconee Nuclear Station recently completed a refueling outage in 38 days, a new Company record.

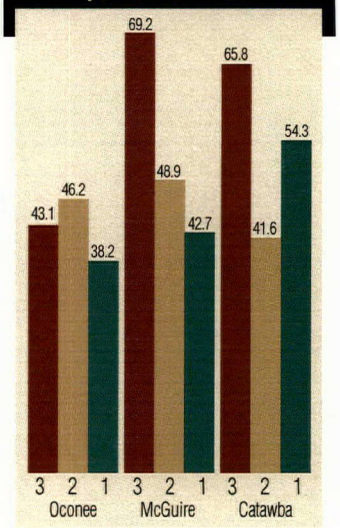


89 percent at Oconee, and 84 percent at Catawba. The industry's top quartile capacity factor in 1994, the most recent year the figure is available, was 90 percent.

The Company has also made excellent progress in reducing the number of outage days required for refueling. A shorter refueling outage means that a nuclear unit returns to service more quickly, potentially lowering costs, and ultimately giving Duke Power greater flexibility in power generation. The most recent nuclear refueling outage occurred at Duke's McGuire Nuclear Station Unit 1, which was refueled in 43 days. In the fall, Oconee Nuclear Station Unit 1 was refueled in 38 days, a new Company record.

Duke's commitment to nuclear excellence is also exemplified by the fact that DE&S' nuclear expertise is highly regarded and sought by public and private sector clients worldwide. DE&S plays a key role in a number of precedent-setting nuclear initiatives, including management of the nation's civilian nuclear waste, licensing of the country's first privately operated uranium enrichment facility, and management, operation, and integration of several of the Department of Energy's national laboratories. DE&S also delivers the resources, skill, and expertise needed to help electric utilities operate more efficiently and cost effectively.

Nuclear Station Refueling History (outage length in days)*



Last three outages for each station, through January, 1996 (1= most recent)

CUSTOMER SATISFACTION

High satisfaction is a key component in retaining customers.

Competition demands that companies meet the needs and expectations of their custom The creation of Duke Power's Customer Service Center, more innovative rates to customers greater flexibility and control over their electric bills, and the redesign of work processes to meet customer expectations more consistently and predictably are directed to that end.

Realizing that outages and poor quality power can have severe effects on customer productivity, Duke has also implemented several power quality and reliability programs. To minimize the adverse effects of lightning, the Company began an intensive program to increase the insulation levels of our transmission lines and to improve grounding. These efforts have produced dramatic reductions in lightning-related outages. The Power Quality Process is an initiative aimed at understanding customers' core business process needs and electric power requirements, the goal being to enhance their individual competitiveness in the marketplace. Other initiatives directed at reducing the number of repeat outages, momentary blinks, and outages caused by falling trees and branches have shown an improving trend the past 24 months.

Duke's Market Research Department routinely surveys residential customers concerning their satisfaction in such matters as power outage and problem resolution, billing and credit issues, and new service or installation requests. The Company has set a target of highly satisfying at least four out of every five customers in these areas. Research shows that high satisfaction is one component in retaining customers. In 1995, 73 percent of customers said they were highly satisfied with the problem resolution process for power outages, and 81 percent were highly satisfied with billing and credit transactions. For new service and installation

transactions, 78 percent of customers reported high satisfaction with their experience. The Company's objective is to improve performance in each area.

In 1995, as part of its ongoing effort to improve customer service, Duke reorganized its eting efforts, naming 15 National Account Managers. These managers are assigned to with Duke's largest customers, serving as a single point of contact to serve all needs of these customers. An internal energy services group was also created to support the managers by providing energy solutions to Duke customers, solutions that can include assuming ownership or operation of a customer's energy assets.

Customer Satisfaction Indicators*

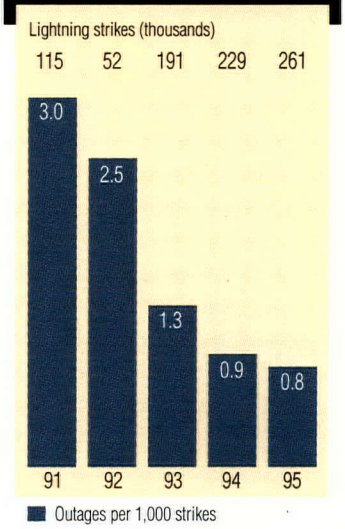
	Overall Satisfaction	Overall Reliability
Duke Power	78.0%	97.0%
Southeast	64.3%	76.2%
National	56.0%	72.6%

Source: TQS Research, Inc. (1995)
*Percentage of customers who are "very satisfied"

Flexible Rate Structures

Schedule HP-X	Provides a limited number of non-residential customers with hourly prices reflective of the Company's generation and transmission costs
Schedule EC	Economic Development schedule designed to encourage new business and expansions to existing businesses
Schedule DIV	Industrial Diversity Rate designed to promote the establishment of distinctly different businesses within the service territory

Transmission System Outages From Lightning Strikes



Duke Power's commitment to customer satisfaction takes many forms. Textile equipment at Dixie Yarns' Threads USA division in Gastonia, N.C., is tested with SagGen, a computerized sag generator designed to subject the equipment to different power quality situations before the equipment is placed into service.

SagGen helps identify potential problems before they can affect a customer's production processes. For most Duke Power residential customers, their contact with the Company occurs through the Customer Service Center, where trained customer representatives are available 24 hours a day to handle all customer inquiries.

CONSOLIDATED STATEMENTS OF INCOME

Dollars in Thousands — Year ended December 31,	1995	1994	1993
Operating revenues (Notes 1, 2 and 11)	**$4,676,684**	$4,488,913	$4,46[illegible]
Operating expenses			
Fuel used in electric generation (Note 1)	**744,226**	705,019	732,246
Net interchange and purchased power (Notes 2 and 3)	**468,293**	553,355	535,125
Other operation and maintenance	**1,403,547**	1,341,659	1,254,028
Depreciation and amortization (Note 1)	**458,131**	459,781	496,971
General taxes	**253,436**	249,273	240,052
Total operating expenses	**3,327,633**	3,309,087	3,258,422
Operating income	**1,349,051**	1,179,826	1,207,811
Interest expense and other income (Note 1)			
Interest expense	**(289,318)**	(270,217)	(274,051)
Allowance for funds used during construction and other deferred returns	**125,040**	111,872	82,600
Other, net	**(3,794)**	14,414	20,032
Total interest expense and other income	**(168,072)**	(143,931)	(171,419)
Income before income taxes	**1,180,979**	1,035,895	1,036,392
Income taxes (Notes 1 and 4)	**466,441**	397,019	409,977
Net income	**714,538**	638,876	626,415
Dividends on preferred and preference stock	**48,903**	49,724	52,429
Earnings for common stock	**$ 665,635**	$ 589,152	$ 573[illegible]
Common stock data (Note 6)			
Average shares outstanding (thousands)	**204,859**	204,859	204,859
Earnings per share	**$3.25**	$2.88	$2.80
Dividends per share	**$2.00**	$1.92	$1.84

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Dollars in Thousands — Year ended December 31,	1995	1994	1993
Balance — Beginning of year	**$2,605,920**	$2,410,825	$2,223,718
Add — Net income	**714,538**	638,876	626,415
Total	**3,320,458**	3,049,701	2,850,133
Deduct			
Dividends			
Common stock	**409,716**	393,370	376,937
Preferred and preference stock	**48,903**	49,724	52,429
Capital stock transactions, net	**3,564**	687	9,942
Total deductions	**462,183**	443,781	439,308
Balance — End of year	**$2,858,275**	$2,605,920	$2,410[illegible]

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Dollars in Thousands — Year ended December 31,	1995	1994	1993
flows from operating activities			
et Income	$ 714,538	$ 638,876	$ 626,415
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash items			
Depreciation and amortization	674,816	647,515	664,355
Deferred income taxes and investment tax credit amortization	5,989	94,261	62,897
Allowance for equity funds used during construction	(23,082)	(27,411)	(17,221)
Purchased capacity levelization	(33,149)	(268,925)	(20,049)
Other, net	76,029	22,460	73,607
(Increase) Decrease in			
Accounts receivable	(136,838)	47,586	(37,131)
Inventory	(14,549)	(28,568)	24,904
Prepayments	(7,178)	(435)	(2,396)
Increase (Decrease) in			
Accounts payable	11,694	(52,506)	(28,184)
Taxes accrued	14,454	(51,641)	25,797
Interest accrued and other liabilities	28,934	14,523	30,508
Total adjustments	597,120	396,859	777,087
Net cash provided by operating activities	1,311,658	1,035,735	1,403,502
Cash flows from investing activities			
Construction expenditures and other property additions	(713,299)	(772,452)	(599,759)
Investment in nuclear fuel	(76,603)	(108,711)	(111,731)
ernal funding for decommissioning	(56,470)	(52,524)	(52,524)
e-funded pension cost	—	(30,000)	(50,000)
Investment in joint ventures	(54,945)	(6,718)	(70,345)
Net change in investment securities	54,425	17,922	46,489
Net cash used in investing activities	(846,892)	(952,483)	(837,870)
Cash flows from financing activities			
Proceeds from the issuance of			
First and refunding mortgage bonds	173,839	343,824	1,395,682
Preferred stock	—	—	215,633
Pollution control bonds	—	—	76,265
Short-term notes payable, net	48,200	86,300	(105,200)
Construction loans and other	47,643	57,032	13,280
Payments for the redemption of			
First and refunding mortgage bonds	(157,365)	(81,781)	(1,399,336)
Preferred stock	(100,516)	(1,500)	(224,295)
Pollution control bonds	—	—	(79,310)
Construction loans and other	(9,416)	(18,885)	(12,454)
Dividends paid	(458,018)	(443,633)	(427,868)
Other	(1,153)	(20,991)	(6,752)
Net cash used in financing activities	(456,786)	(79,634)	(554,355)
Net increase in cash	7,980	3,618	11,277
Cash at beginning of year	37,430	33,812	22,535
t end of year	$ 45,410	$ 37,430	$ 33,812

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Assets

Dollars in Thousands December 31,	1995	1994
Current assets		
Cash (Notes 5 and 10)	$ 45,410	$ 3[illegible]
Short-term investments (Notes 1 and 10)	76,300	132,692
Receivables (less allowance for losses: 1995 - $6,352; 1994 - $6,637) (Note 1)	689,703	552,865
Inventory — at average cost	341,841	319,385
Prepayments and other	22,900	15,722
Total current assets	1,176,154	1,058,094
Investments and other assets		
Investments in joint ventures (Note 11)	163,274	108,330
Other investments, at cost or less (Note 10)	85,194	83,226
Nuclear decommissioning trust funds (Notes 10 and 14)	273,466	172,390
Pre-funded pension cost (Note 12)	80,000	80,000
Total investments and other assets	601,934	443,946
Property, plant and equipment (Notes 1, 3, 9, 13 and 14)		
Electric plant in service (at original cost)		
Production	7,154,332	6,747,397
Transmission	1,532,302	1,439,435
Distribution	4,105,513	3,965,393
Other	1,030,226	1,020,192
Electric plant in service	13,822,373	13,172,417
Less accumulated depreciation and amortization	5,122,192	4,810,004
Electric plant in service, net	8,700,181	8,362,413
Nuclear fuel	731,691	757,983
Less accumulated amortization	453,921	415,560
Nuclear fuel, net	277,770	342,423
Construction work in progress (including nuclear fuel in process: 1995 - $25,500; 1994 - $52,273)	382,582	55[illegible]
Total electric plant, net	9,360,533	9,263,566
Other property — at cost (less accumulated depreciation: 1995 - $29,956; 1994 - $24,137)	354,713	302,383
Total property, plant and equipment, net	9,715,246	9,565,949
Deferred debits (Notes 1, 3, 4 and 13)		
Purchased capacity costs	965,473	932,324
Debt expense	180,930	186,306
Regulatory asset related to income taxes	490,676	489,292
Regulatory asset related to DOE assessment fee	101,274	102,467
Other	126,797	83,850
Total deferred debits	1,865,150	1,794,239
Total assets	$13,358,484	$12,862,228

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS
Liabilities and Stockholders' Equity

Dollars in Thousands December 31,	1995	1994
Current liabilities		
Accounts payable	$ 343,692	$ 343,688
Notes payable (Notes 5 and 10)	155,300	107,100
Taxes accrued (Note 1)	34,884	29,999
Interest accrued	73,675	72,157
Current maturities of long-term debt and preferred stock (Notes 8 and 9)	12,071	93,759
Other (Note 13)	149,555	121,539
Total current liabilities	769,177	768,242
Long-term debt (Notes 5, 9 and 10)	3,711,405	3,567,122
Accumulated deferred income taxes (Notes 1 and 4)	2,382,204	2,348,631
Deferred credits and other liabilities		
Investment tax credit (Notes 1 and 4)	261,347	272,594
DOE assessment fee (Note 1)	101,274	102,467
Nuclear decommissioning costs externally funded (Note 14)	273,466	172,390
Other	390,427	318,453
Total deferred credits and other liabilities	1,026,514	865,904
Preferred and preference stock with sinking fund requirements (Notes 8 and 10)	234,000	279,500
Preferred and preference stock without sinking fund requirements (Notes 7 and 10)	450,000	500,000
Commitments and contingencies (Note 13)		
Common stockholders' equity (Note 6)		
Common stock, no par, 300,000,000 shares authorized; 204,859,339 shares outstanding for 1995 and 1994	1,926,909	1,926,909
Retained earnings	2,858,275	2,605,920
Total common stockholders' equity	4,785,184	4,532,829
Total liabilities and stockholders' equity	$13,358,484	$12,862,228

See Notes to Consolidated Financial Statements.

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Nature of Operations

The Company is primarily engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas. The Company is one of the nation's largest investor-owned electric utilities.

The Company is also engaged in a variety of diversified operations, most of which are organized in separate subsidiaries. The Company's subsidiaries and diversified activities are in the Associated Enterprises Group (AEG). AEG includes Church Street Capital Corp.; Crescent Resources, Inc.; Duke Energy Group, Inc.; Duke Engineering & Services, Inc.; Duke/Fluor Daniel; Duke Merchandising; DukeNet Communications, Duke Water Operations; and Nantahala Power and Light Company. Certain of these subsidiaries have invested in both domestic and international joint ventures. (See Note 11.)

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

B. Revenues

Electric revenues are recorded as service is rendered to customers. "Receivables" on the Consolidated Balance Sheets include $206,792,000 and $163,270,000 as of December 31, 1995 and 1994, respectively, for electric service that has been rendered but not yet billed to customers.

C. Additions to Electric Plant

The Company capitalizes all construction-related direct labor and materials as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of money (allowance for funds used during 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.

D. Allowance for Funds Used During Construction (AFUDC)

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

The AFUDC rates of 9.3, 9.6 and 9.3 percent for Duke Power for 1995, 1994 and 1993, respectively, include a component for debt cost on a pre-tax basis. Rates for all periods are compounded semiannually.

E. Other Deferred Returns

Other deferred returns represent the estimated financing costs associated with funding certain regulatory assets. These regulatory assets primarily arise from the Company's funding of purchased capacity costs above levels collected in rates. Other deferred returns are non-cash items. They are primarily recognized as an addition to "Purchased capacity costs" and as an offsetting credit to "Interest expense and other income."

F. Depreciation and Amortization of Electric Plant

Provisions for electric plant depreciation are recorded using the straight-line method. The year-end composite weighted-average depreciation rates were 3.48, 3.46 and 3.47 percent for 1995, 1994 and 1993, respectively.

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

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

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid $9,205,000 during 1995 and has paid $35,551,000 cumulatively related to its owned interest in nuclear plants. The Company has reflected remaining liability and regulatory asset of $101,274,000 in the Consolidated Balance Sheets at December 31, 1995.

G. Subsidiaries

The Company's consolidated financial statements reflect consolidation of all of its majority-owned subsidiaries. Intercompany transactions have been eliminated in consolidation.

H. Income Taxes

The Company and its subsidiaries file a consolidated federal income tax return.

Deferred income taxes have been provided for temporary differences. Temporary differences occur when events and transactions recognized for financial reporting result in taxable or tax-deductible amounts in future periods. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

I. Unamortized Debt Premium, Discount and Expense

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

J. Consolidated Statements of Cash Flows

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

Total income taxes paid were $441,440,000, $372,416,000 and $354,981,000 for the years ended December 31, 1995, 1994 and 1993, respectively.

Interest paid, net of amounts capitalized, was $258,698,000, $236,696,000 and $249,659,000 for the years ended December 31, 1995, 1994 and 1993, respectively.

K. Cost-Based Regulation

As a regulated entity, the Company is subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Accordingly, the Company records certain [illegible] and liabilities that result from the effects of the ratemaking process that would not be recorded under generally accepted accounting principles for non-regulated entities. Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced, and utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require the affected utilities to write off their associated regulatory assets. The regulatory assets of the Company are classified as "Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

NOTE 2. RATE MATTERS

Duke Power Company

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

The most recent general rate increase requests in the Company's retail jurisdictions were filed and approved in 1991. The Company also filed its most recent general rate increase request within the FERC wholesale jurisdiction in 1991. A [illegible]iated settlement between the Company and the wholesale [illegible]mers was approved by the FERC in 1992.

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

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

A bill ratified by the North Carolina legislature in 1987 to assure the legality of such adjustments in rates had its expiration provision repealed in March 1995.

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

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Nantahala Power and Light Company
During 1992, Nantahala Power and Light Company (NP&L) filed an application for a general rate increase with the NCUC. A general rate increase was approved in June 1993 which resulted in additional annual revenues of $4.3 million. Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES

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

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

Each owner has provided its own financing for its ownership interest in the station.

The Company retains a 12.5 percent ownership interest in the Catawba Nuclear Station. As of December 31, 1995, $499,209,000 of "Electric plant in service" and "Nuclear fuel" represents the Company's investment in Units 1 and 2. Accumulated depreciation and amortization of $185,264,000 associated with Catawba has been recorded as of year-end. The Company's share of operating costs of Catawba is included in the Consolidated Statements of Income.

In connection with the joint ownership, the Company has entered into contractual agreements with the other joint owners to purchase declining percentages of the generating capacity and energy from the plant. These purchased power agreements were effective beginning with the commercial operation of each unit. Unit 1 and Unit 2 began commercial operation in June 1985 and August 1986, respectively. The purchased power agreements were established for 15 years for NCMPA and PMPA and 10 years for NCEMC and Saluda River. While the purchased power agreements with NCMPA and PMPA extend for 15 years, a significant decrease in the percentage of capacity and energy the Company is obligated to purchase occurs in the 11th calendar year of operation for each unit. This significant decrease occurred in 1995 for Unit 1 and will occur in 1996 for Unit 2. Certain provisions in the agreements with NCEMC and Saluda River have moderated the rate of decrease in the percentage of capacity and energy that the Company is obligated to purchase until 1996 when the Company has no further obligation to purchase capacity and related energy.

The agreements also provide for supplemental power sales by the Company to the other joint owners. Such power sales are to satisfy capacity and energy needs of the other joint owners beyond the capacity and energy which they retain from Catawba or potentially acquire in the form of other resources. As the joint owners retain more capacity and energy from Catawba, or a third party, supplemental power sales are expected to decline.

The agreements with each of the other joint owners include provisions that the Company will provide generating reserves to backstand the other joint owners' retained capacity in the Catawba plant at the system average cost of installed capacity. Additionally, the agreements include certain reliability exchanges designed to manage outage-related risks by exchanging energy entitlements between the Catawba Nuclear Station and the McGuire Nuclear Station, impacting the Company as well as all the other joint owners.

Purchased energy cost payments are based on variable operating costs and are a function of the generation output of Catawba. Purchased capacity payments are based on fixed costs of the plant and include the capital costs and fixed operating and maintenance costs. Actual purchased capacity costs for 1995 and projected obligations for 1996 through 2000, including the impact of the 1995 settlement agreement with NCMPA and PMPA (See Note 13), are as follows (dollars in thousands):

Year	Purchased Capacity Capital Cost	Purchased Capacity Fixed O&M	Total Purchased Capacity
1995 Actual	$237,978	$83,358	$321,336
1996 Projected	$83,870	$41,510	$125,380
1997 Projected	$65,803	$35,042	$100,845
1998 Projected	$47,609	$26,541	$74,150
1999 Projected	$34,752	$19,646	$54,398
2000 Projected	$4,217	$2,542	$6,759

Effective in its November 1991 rate order, the North Carolina Utilities Commission reaffirmed the Company's recovery, on a levelized basis, of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners. The Public Service Commission of South Carolina in its November 1991 rate order reaffirmed the Company's recovery on a levelized basis of the capital costs of capacity purchased from the other joint owners. Levelization was reaffirmed through inclusion in rates approved in March 1992 by the Federal Energy Regulatory Commission (FERC). The portion of purchased capacity subject to levelization currently recovered in rates is being deferred, and the Company is recording a return on the accumulated balance. The Company recovers the accumulated balance, including the

return, when the sum of the declining purchased capacity payments and accrual of returns for the current period drops below the levelized revenues. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups. The Company recovers the costs of purchased energy and the non-levelized portion of purchased capacity on a current basis.

The current levelized revenues approved in the Company's last general rate proceedings are $211,423,000, $94,137,000 and $6,815,000 for North Carolina retail, South Carolina retail and Other Wholesale (FERC), respectively. Purchased power costs, subject to levelization, are deferred based on allocation factors of approximately 62 percent, 26 percent and 2 percent for North Carolina retail, South Carolina retail and Other Wholesale (FERC), respectively. The Company also recovers an allocated amount of purchased power costs in the pricing of supplemental sales made to the other joint owners on a current basis.

In 1995, in the North Carolina retail and FERC wholesale jurisdictions, purchased capacity payments and the accrual of deferred returns continued to exceed levelized revenues. However, in 1996, the levelized revenues are expected to exceed the purchased capacity payments and accrual of deferred returns. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments and accrual of deferred returns.

For the years ended December 31, 1995, 1994 and 1993, the Company recorded purchased capacity and energy costs from the other joint owners of $388,246,000, $604,505,000 and $547,899,000, respectively. These amounts, after adjustments for the costs of capacity purchased not reflected in current rates, are included in "Net interchange and purchased power" in the Consolidated Statements of Income. As of December 31, 1995 and 1994, $965,473,000 and $932,324,000, respectively, associated with the cost of capacity purchased but not reflected in current rates have been accumulated in the Consolidated Balance Sheets as "Purchased capacity costs."

NOTE 4. INCOME TAX EXPENSE

Accumulated deferred income taxes consist primarily of the following (dollars in thousands):

	December 31, 1995		December 31, 1994	
Excess tax over book depreciation at historical tax rates	$1,387,925		$1,343,605	
Regulatory liability related to adjusting deferred taxes to the current statutory tax rate	(114,538)*		(120,422)*	
Net excess tax over book depreciation		$1,273,387		$1,223,183
Regulatory asset related to restating to a pre-tax basis		605,214*		609,714*
Deferred Catawba purchased capacity costs		374,112		361,018
Book versus tax basis difference		60,443		89,058
Loss on bond redemptions		68,135		70,067
Other		913		(4,409)
Total deferred income taxes		$2,382,204		$2,348,631

* The net regulatory asset related to income taxes is $490,676,000 for 1995 and $489,292,000 for 1994.

Total deferred income tax liability was $2,946,711,000 as of December 31, 1995, and $2,873,373,000 as of December 31, 1994. Total deferred income tax asset was $564,507,000 as of December 31, 1995, and $524,742,000 as of December 31, 1994.

Income tax expense for the years ended December 31, 1995, 1994 and 1993 consisted of the following (dollars in thousands):

	1995	1994	1993
Current income taxes			
Federal	$377,237	$249,968	$283,930
State	83,215	52,790	63,150
Total current income taxes	460,452	302,758	347,080
Deferred taxes, net			
Federal	13,466	83,359	59,267
State	3,770	22,153	14,887
Total deferred taxes, net	17,236	105,512	74,154
Investment tax credit amortization	(11,247)	(11,251)	(11,257)
Total income tax expense	$466,441	$397,019	$409,977

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Income taxes differ from amounts computed by applying the statutory tax rate to pre-tax income for the years ended December 31, 1995, 1994 and 1993 as follows (dollars in thousands):

	1995	1994	1993
Income taxes on pre-tax income at the statutory federal rate of 35%	$413,343	$362,563	$362,737
Increase (reduction) in tax resulting from:			
Allowance for funds used during construction (AFUDC)	(8,079)	(9,594)	(6,027)
Amortization of investment tax credit deferrals	(11,247)	(11,251)	(11,257)
AFUDC in book depreciation/amortization	21,057	19,027	25,694
Deferred income tax flowback at rates higher than statutory	(5,675)	(5,530)	(9,091)
State income taxes, net of federal income tax benefits	56,210	47,872	51,289
Other items, net	832	(6,068)	(3,368)
Total income tax expense	$466,441	$397,019	$409,977

NOTE 5. SHORT-TERM BORROWINGS AND CREDIT FACILITIES

The following credit facilities were available to the Company at December 31, 1995 and 1994, with 25 and 26 commercial banks, respectively:

Type of Facility	Line of Credit at December 31, 1995	Outstanding at December 31, 1995	Line of Credit at December 31, 1994	Outstanding at December 31, 1994
Annually renewable lines of credit	$ 64,900,000	$29,300,000	$ 44,980,000	$10,100,000
Two-year revolving facilities (a)	40,000,000	—	40,000,000	—
Three-year revolving facilities (b)	355,000,000	—	355,000,000	—
Four-year revolving facilities (c)	210,000,000	30,043,000	—	—
	$669,900,000	$59,343,000	$439,980,000	$10,100,000

(a) The Company had $40,000,000 in pollution control bonds, included in long-term debt, outstanding throughout 1995 and 1994 backed by the unused portion of these facilities.
(b) The Company had $130,000,000 in commercial paper, included in long-term debt, outstanding throughout 1995 and 1994 backed by the unused portion of these facilities.
(c) The outstanding balance of $30,043,000 is included in long-term debt.

Cash balances maintained at the banks on deposit were $17,120,000 as of December 31, 1995, and $13,214,000 as of December 31, 1994. Cash balances and fees compensate banks for their services, even though the Company has no formal compensating-balance arrangements. To compensate certain banks for credit facilities, the Company maintained balances of $45,000 and $49,000 as of December 31, 1995 and 1994, 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):

	Twelve Months Ended		
	December 31, 1995	December 31, 1994	December 31, 1993
Amount outstanding at end of period — average rate of 5.91% as of December 31, 1995, 6.02% as of December 31, 1994, and 3.55% as of December 31, 1993	$155,300	$107,100	$ 20,800
Maximum amount outstanding during the period	$264,300	$143,400	$180,800
Average amount outstanding during the period	$ 88,470	$ 24,161	$ 35,366
Weighted-average interest rate for the period — computed on a daily basis	6.05%	4.58%	3.19%

NOTE 6. COMMON STOCK AND RETAINED EARNINGS

Common Stock

As of December 31, 1995, a total of 7,004,659 shares was reserved for issuance for stock plans.

Retained Earnings

As of December 31, 1995, substantially all of the Company's retained earnings were unrestricted as to the declaration or payment of dividends.

NOTE 7. PREFERRED AND PREFERENCE STOCK WITHOUT SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1995 and 1994:

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

As of December 31, 1995 and 1994, there were no shares of preference stock outstanding. Preferred stock without sinking fund requirements as of December 31, 1995 and 1994, was as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1995	1994
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
7.85% S	1992	600,000	60,000	60,000
7.00% W	1993	500,000	50,000	50,000
7.04% Y	1993	600,000	60,000	60,000
7.72% (Preferred Stock A)	1992	1,600,000	40,000	40,000
6.375% (Preferred Stock A)	1993	2,400,000	60,000	60,000
Adjustable Rate A	1986	500,000	—	50,000
Auction Series A	1990	750,000	75,000	75,000
Total			$450,000	$500,000

NOTE 8. PREFERRED AND PREFERENCE STOCK WITH SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1995 and 1994:

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

As of December 31, 1995 and 1994, there were no shares of preference stock outstanding. Preferred stock with sinking fund requirements as of December 31, 1995 and 1994, was as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1995	1994
5.95% B (Preferred Stock A)	1992	800,000	$ 20,000	$ 20,000
6.10% C (Preferred Stock A)	1992	800,000	20,000	20,000
6.20% D (Preferred Stock A)	1992	800,000	20,000	20,000
7.12% Q	1987	470,000	—	47,000
7.50% R	1992	850,000	85,000	85,000
6.20% T	1992	130,000	13,000	13,000
6.30% U	1992	130,000	13,000	13,000
6.40% V	1992	130,000	13,000	13,000
6.75% X	1993	500,000	50,000	50,000
Less: Current sinking fund requirements				
7.12% Q			—	(1,500)
Total			$234,000	$279,500

The annual sinking fund requirements through 2000 are $ in 1996 and 1997, $4,250,000 in 1998, $24,250,000 in 1999 and $37,250,000 in 2000. Some additional redemptions are permitted at the Company's option.

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

NOTE 9. LONG-TERM DEBT

Long-term debt outstanding as of December 31, 1995 and 1994, was as follows (dollars in thousands):

Series	Year Due	1995	1994
First and refunding mortgage bonds:			
6.47%-6.60%	1995	$ —	$ 40,300
4 1/2%	1995	—	40,000
6.59%	1996	3,000	3,000
5 3/8%	1997	72,600	72,600
5 5/8%	1997	100,000	100,000
5.17%	1998	50,000	50,000
7.5%	1999	100,000	100,000
6 1/4%	1999	65,000	65,000
5.76%	1999	5,000	5,000
5.78%	1999	25,000	25,000
5.79%	1999	30,000	30,000
8% B	1999	200,000	200,000
7%	2000	100,000	100,000
7% B	2000	100,000	100,000
5 7/8%	2001	150,000	150,000
6 5/8% B	2003	100,000	100,000
5 7/8% C	2003	75,000	75,000
6.125%	2003	75,000	75,000
8%	2004	75,000	75,000
6 1/4% B	2004	100,000	100,000
7.37%-7.41%	2004	100,000	100,000
7%	2005	200,000	200,000
6 3/8%	2008	125,000	125,000
9 5/8%	2020	—	46,982
10 1/8% B	2020	—	24,854
8 3/4%	2021	150,000	150,000
8 3/8% B	2021	150,000	150,000
8 5/8%	2022	100,000	100,000
7 3/8%	2023	200,000	200,000
6 7/8% B	2023	200,000	200,000
7 7/8%	2024	150,000	150,000
6 3/4%	2025	150,000	150,000
(continued)			
7 1/2% B	2025	$ 100,000	$ —
8.27%	2025	21,000	—
8.27%	2025	50,000	—
8.28%	2025	2,000	—
8.30%	2025	5,000	—
8.95%	2027	15,681	15,769
7%	2033	150,000	150,000
Pollution Control bonds:			
7.70%	2012	20,000	20,000
7.75% B	2017	10,000	10,000
7.50%	2017	25,000	25,000
3.76%	2014	40,000	40,000
5.80%	2014	77,000	77,000
Subtotal		3,466,281	3,440,505
Other long-term debt:			
Capitalized leases		7,477	26,039
Other long-term debt		147,410	130,000
Unamortized debt discount and premium, net		(61,674)	(62,918)
Current maturities of long-term debt		(4,295)	(81,926)
Subtotal (a)		3,555,199	3,451,700
Subsidiary long-term debt:			
Crescent Resources, Inc. (b)		130,694	92,102
Nantahala Power and Light		33,288	33,653
Current maturities of long-term debt		(7,776)	(10,333)
Subtotal		156,206	115,422
Total long-term debt		$3,711,405	$3,567,122

(a) Substantially all of Duke Power's electric plant was mortgaged as of December 31, 1995.
(b) Substantial amounts of Crescent Resources, Inc.'s real estate development projects, land and buildings are pledged as collateral.

As of December 31, 1995 and 1994, the Company had $40,000,000 in pollution control revenue bonds backed by an unused, two-year revolving credit facility of $40,000,000. In addition, the Company had $130,000,000 in commercial paper outstanding throughout 1995 and 1994 backed by unused three-year revolving credit facilities. These facilities are on a fee basis. Both the $40,000,000 in pollution control bonds and the $130,000,000 in commercial paper are included in long-term debt.

As of December 31, 1995, Crescent Resources, Inc. had $65,526,000 in mortgage loans which mature through 2000 and $35,125,000 in mortgage loans maturing in 2001 or thereafter. Additionally, Crescent Resources, Inc. had $30,043,000 outstanding at December 31, 1995, included in long-term debt on a $50,000,000 four-year revolving credit facility. Interest rates are variable and at December 31, 1995, ranged from 5.50 percent to 7.10 percent. As of December 31, 1995, Nantahala Power and Light Company had $33,000,000 in senior notes maturing in 2011 and 2012. The two notes carry fixed interest rates of 9.21 percent and 7.45 percent and require monthly payments of principal beginning in 1997 and 1998, respectively.

The annual maturities of consolidated long-term debt, including capitalized lease principal payments through 2000, are $12,071,000 in 1996; $215,476,000 in 1997; $63,097,000 in 1998; $473,326,000 in 1999; and $206,583,000 in 2000.

NOTE 10. FINANCIAL INSTRUMENTS

The carrying amounts of "Cash," "Short-term investments," and "Notes payable" on the Consolidated Balance Sheets approximate fair value primarily because of the short maturities of these instruments. "Other investments" substantially consist of notes receivable issued at fixed rates with maturities up to 30 years for which there are no quoted market prices. Due to the numerous outstanding notes, it was not practicable or cost beneficial for the Company to estimate the fair value of these instruments. The majority of estimated fair value amounts of long-term debt and preferred stock as disclosed below were obtained from independent parties. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 1995 and 1994, are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

External funds have been established, as required by the Nuclear Regulatory Commission, as a mechanism to fund certain costs of nuclear decommissioning. (See Note 14.) Currently, these nuclear decommissioning trust funds are invested in U.S. stocks, bonds and cash equivalents. "Nuclear decommissioning trust funds" are presented on the Consolidated Balance Sheets at amounts that approximate fair value.

The carrying amounts and estimated fair values of long-term debt and preferred stocks are as follows (dollars in thousands):

	December 31, 1995		December 31, 1994	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$3,777,672	$3,879,000	$3,696,260	$3,392,000
Preferred stock	$ 684,000	$ 689,000	$ 781,000	$ 697,000

In order to obtain variable rate financing at an attractive cost, the Company entered into interest rate swap agreements associated with the November 29, 1994, issuance of $200 million aggregate principal amount of its First and Refunding Mortgage Bonds, 8% Series B due 1999 and the August 21, 1995, issuance of $100 million aggregate principal amount of its First and Refunding Mortgage Bonds, 7 1/2% Series B due 2025. The interest rate swaps are reset quarterly based upon the London Interbank Offered Rate (LIBOR). As a result of interest rate swap contracts, interest expense on the Consolidated Statements of Income is recognized at the weighted average rate for the year tied to the LIBOR rate. The weighted average rates are as follows (dollars in thousands):

			Weighted Average Rate	
Series	Year Due	Face Value	1995	1994
8% Series B	1999	$200,000	6.14%	5.95%
7 1/2% Series B	2025	$100,000	7.06%	—

The Company also entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Japanese yen associated with various steam generator contracts. The hedge transaction, with a notional amount of approximately $25 million at December 31, 1994, was fully liquidated by November 1995. The Company recorded any gains or losses associated with the hedge as an adjustment to the capitalized cost of the steam generators.

Duke Energy Group, Inc. has entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Chilean peso associated with expected equity contributions over the next two years to a joint venture. The hedge transaction had a notional amount of approximately $17 million at December 31, 1995. Duke Energy Group, Inc. records any gains or losses associated with the hedge as an adjustment to investments in joint ventures.

NOTE 11. INVESTMENTS IN JOINT VENTURES

Certain investments in joint ventures are accounted for by the equity method. The Company's ownership in domestic and international joint ventures is 50 percent or less. The Company's proportionate share of net income in joint ventures for the years ended December 31, 1995, 1994 and 1993 was $9,237,000, $7,049,000 and $2,601,000, respectively. These amounts are reflected in "Operating revenues" on the Consolidated Statements of Income.

A summary of assets and liabilities of joint ventures follows (dollars in thousands):

	December 31, 1995		December 31, 1994	
	Total	Company's Proportionate Share	Total	Company's Proportionate Share
Assets of joint ventures	$1,445,600	$351,376	$1,117,449	$272,836
Liabilities of joint ventures	$ 615,452	$188,102	$ 504,029	$164,506

Of the $615,452,000 and $504,029,000 of total liabilities outstanding at December 31, 1995 and 1994, respectively, $[illegible],289,000 and $407,605,000 represent non-recourse debt at December 31, 1995 and 1994, respectively, for which the Company bears no responsibility beyond the loss of its investment and loans made to certain joint ventures in the event the joint venture defaults on the debt. These loans were approximately $23,170,000 at December 31, 1995.

NOTE 12. RETIREMENT BENEFITS

A. Retirement Plan

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own retirement plans, have a non-contributory, defined benefit retirement plan covering substantially all their employees. The benefit is based upon an age-related formula which takes into account years of creditable service and the employee's average compensation based upon the highest compensation during a consecutive sixty-month period. The benefit is reduced by an adjustment which is based upon the empl[illegible] social security wages. Normal retirement age under the P[illegible] age 65; however, early retirement benefits are payable as early as age 55 with 10 years of creditable service or age 51 if the employee has at least 30 years of creditable service. The Company's policy is to fund pension costs as accrued. During 1994, the Company made additional contributions of $30,000,000 to enhance the funded position of the plan.

Net periodic pension cost for the years ended December 31, 1995, 1994 and 1993, include the following components (dollars in thousands):

	1995		1994		1993	
Service cost benefit earned during the year		$ 46,402		$43,098		$39,514
Interest cost on projected benefit obligation		111,110		96,521		93,347
Actual return on plan assets	(253,314)		(6,138)		(117,898)	
Amount deferred for recognition	144,022		(86,995)		35,652	
Expected return on plan assets		(109,292)		(93,133)		(82,246)
Net amortization		6,161		7,657		4,137
Net periodic pension cost		$ 54,381		$54,143		$54,752

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1995 and 1994, is as follows (dollars in thousands):

	1995	1994
Accumulated benefit obligation:		
Vested benefits	$(1,289,459)	$(1,070,355)
Nonvested benefits	(6,216)	(4[illegible]
Accumulated benefit obligation	$(1,295,675)	$(1,074[illegible]
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	$ 1,424,148	$ 1,167,158
Projected benefit obligation	(1,596,747)	(1,368,740)
Unrecognized net experience loss	286,837	319,519
Unrecognized prior service cost reduction	(35,039)	(38,872)
Remaining unrecognized transitional obligation	801	935
Pre-funded pension cost	$ 80,000	$ 80,000

In determining the projected benefit obligation, the weighted-average assumed discount rate used was 7.50 percent in 1995, 8.25 percent in 1994 and 7.50 percent in 1993. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 4.75 percent in 1995, 5.40 percent in 1994 and 4.50 percent in 1993. The expected long-term rate of return on plan assets used in determining pension cost was 9.00 percent in 1995, 9.00 percent in 1994 and 8.40 percent in 1993.

During 1995, the Company offered to certain employees an Enhanced Vested Benefits program (EVB). The Company recorded an additional one-time expense for special termination benefits associated with EVB of approximately $42,196,000, including $21,600,000 of additional retirement plan costs.

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 (NP&L), has maintained its own postretirement benefit plans, currently provide certain health care and life insurance benefits for retired employees. However, NP&L employees who retire after January 1, 1996, will be covered by Duke Power Company's postretirement benefit plan. 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 $23,000,000 into these funding mechanisms in 1995 and $12,269,000 in 1994.

Net periodic postretirement benefit cost for the years ended December 31, 1995, 1994 and 1993, include the following components (dollars in thousands):

	1995		1994		1993	
Service cost benefit earned during the year		$ 5,874		$ 5,415		$ 4,974
Interest cost on accumulated postretirement benefit obligation		27,201		25,321		25,482
Actual return on plan assets	(14,726)		(1,451)		(4,143)	
Amount deferred for recognition	7,260		(3,469)		334	
Expected return on plan assets		(7,466)		(4,920)		(3,809)
Straight-line — 20 year amortization of transitional obligation		13,293		13,293		13,479
Other amortization		555		366		278
Net periodic postretirement benefit cost		$ 39,457		$ 39,475		$ 40,404

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, and 1994, is as follows (dollars in thousands):

	1995		1994	
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		$105,506		$ 69,987
Actives eligible to retire	(25,780)		(11,902)	
Actives not eligible to retire	(97,389)		(90,499)	
Retirees and surviving spouses	(253,688)		(239,978)	
Accumulated postretirement benefit obligation		(376,857)		(342,379)
Unrecognized prior service cost		712		783
Unrecognized net experience loss		25,955		14,448
Unrecognized transitional obligation		212,695		225,988
(Accrued) postretirement benefit cost		$ (31,989)		$ (31,173)

In determining the accumulated postretirement benefit obligation (APBO), the weighted-average assumed discount rate used was 7.50 percent in 1995, 8.25 percent in 1994 and 7.50 percent in 1993. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 4.75 percent in 1995, 5.40 percent in 1994 and 4.50 percent in 1993. The expected long-term rate of return on 401(h) assets used in determining postretirement benefits cost was 9.00 percent in 1995, 9.00 percent in 1994 and 8.40 percent in 1993. For Retired Lives Reserve assets, 8.00 percent was used in 1995, 6.50 percent in 1994 and 7.13 percent in 1993.

The assumed medical inflation rate was approximately 10.5 percent in 1995. This rate decreases by 0.5 percent to 1.0 percent per year until a rate of 5.5 percent is achieved in the year 2001, which remains fixed thereafter.

A 1.0 percent increase in the medical and dental trend rates produces a 4.81 percent ($1,589,000) increase in the aggregate service and interest cost. The increase in the APBO attributable to a 1.0 percent increase in the medical and dental trend rates is 9.22 percent ($38,281,000) as of December 31, 1995.

NOTE 13. COMMITMENTS AND CONTINGENCIES

A. Construction Program

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including allowance for funds used during construction, are $2.3 billion and $661 million, respectively, for 1996 through 2000. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

Projected capital expenditures of subsidiaries and diversified activities are $1.0 billion for 1996 through 2000. These projections are subject to periodic review and revisions and may vary significantly as the business plans of the Associated Enterprises Group evolve to meet the opportunity presented by its markets.

B. Nuclear Insurance

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

Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $8.9 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $8.7 billion, which will be increased by $79.3 million as each additional commercial nuclear reactor is licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. The $8.7 billion could also be reduced by $79.3 million for certain nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs and public liability damages exceed primary insurances, licensees may be assessed up to $79.3 million for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $79.3 million amount is subject to indexing for inflation and may be subject to state premium taxes. This amount is further subject to a surcharge of 5 percent (which is included in the above $8.7 billion figure) if funds are insufficient to pay claims and associated costs. If retrospective premiums were to be assessed, the other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of such assessment.

The Company is a member of Nuclear Mutual Limited (NML), which provides $500 million in primary property damage coverage for each of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $36 million. This amount represents 5 times the Company's annual premium to NML. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NML policies applicable to Catawba.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. NEIL provides excess insurance coverage of $2.25 billion for the Catawba Nuclear Station and $1.5 billion for each of the Oconee and McGuire Nuclear Stations. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, the Company will be liable, on a pro rata basis, for additional assessments of up to $61 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 participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Each unit of the Oconee, McGuire and Catawba Nuclear Stations is insured for up to approximately $3.5 million per week, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100 percent for 52 weeks and 80 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $30 million. This amount represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage 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 Company and North Carolina Municipal Power Agency Number 1 and Piedmont Municipal Power Agency, two of the other joint owners of the Catawba Nuclear Station, entered into a settlement in September 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the North Carolina Utilities Commission on January 16, 1996 and the Public Service Commission of South Carolina on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information, see Note 3.) In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or financial position of the Company.

Note 14. Nuclear Decommissioning Costs

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the North Carolina Utilities Commission and the Public Service Commission of South Carolina have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume each unit will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 - 2013, Oconee 3 - 2014; McGuire 1 - 2021, McGuire 2 - 2023; and Catawba 1 - 2024, Catawba 2 - 2026.

The Nuclear Regulatory Commission issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1995, the Company expensed approximately $56,470,000 which was contributed to the external funds and accrued an additional $1,319,000 to the internal reserve. Nuclear units are depreciated at a rate of 4.70 percent, of which 1.61 percent is for decommissioning. The balance of the external funds as of December 31, 1995, was $273,466,000. The balance of the internal reserve as of December 31, 1995, was $206,155,000 and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

Note 15. Reclassification

In the Consolidated Statements of Income and Consolidated Statements of Cash Flows, certain 1993 information has been reclassified to conform with 1994 classifications.

Independent Auditors' Report

Duke Power Company:

We have audited the accompanying consolidated balance sheets of Duke Power Company and subsidiaries (the Company) as of December 31, 1995 and 1994, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1995. 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, 1995 and 1994, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1995 in conformity with generally accepted accounting principles.

Deloitte & Touche LLP

Charlotte, North Carolina
February 9, 1996

Deloitte & Touche LLP

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, procedures, and a strong internal audit program augment Company's accounting controls.

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

Jeffrey L. Boyer
Controller

RESULTS OF OPERATIONS

Earnings and Dividends

Earnings per share increased 13 percent from $2.88 in 1994 to $3.25 in 1995. The increase was primarily due to increased kilowatt-hour sales to weather sensitive classes.

Earnings per share increased from $2.80 in 1993 to $3.25 in 1995, indicating an average annual growth rate of 8 percent. Total Company earned return on average common equity was 14.3 percent in 1995 compared to 13.3 percent in 1994 and 13.6 percent in 1993.

The Company continued its practice of annually increasing the common stock dividend. Common dividends per share increased at an average annual rate of 4 percent from $1.84 in 1993 to $2.00 in 1995. Indicated annual dividends per share increased to $2.04.

Revenues and Sales

Operating revenues increased at an average annual rate of 2 percent from 1993 to 1995, primarily because of increased retail kilowatt-hour sales to weather sensitive classes and growth in the general service and industrial customer classes. As discussed below, increased retail sales were partially offset by decreased sales to wholesale customers. Revenues from subsidiaries and diversified operations contributed $73 million to the increase in revenues over the three-year period, primarily from increased developed lot and land sales and engineering services and construction fees.

Wholesale revenues declined in 1995 and are expected to decline again in 1996 as a result of the retention of significantly larger portions of ownership entitlement by the other joint owners of the Catawba Nuclear Station. This increased retention reduces the joint owners' supplemental requirements supplied by the Company. The effect on earnings of such wholesale revenue declines is partially offset by declines in purchased power costs from the other joint owners which are not subject to levelization. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

Kilowatt-hour sales from Duke Power electric operations increased 2 percent in 1995 compared to 1994. Sales to residential, general service and other industrial customers increased by 4 percent, 5 percent and 4 percent, respectively, as a result of warmer summer weather, cooler winter weather and continued economic growth in Duke Power's service area. However, sales to textile customers decreased 1 percent. Wholesale sales decreased 19 percent primarily due to a decrease of 36 percent in supplemental sales requirements to the other joint owners of the Catawba Nuclear Station. A new record peak demand of 15,542 megawatts was set in August 1995 during warmer than normal temperatures.

Operating Expenses

From 1994 to 1995, other operation and maintenance expenses increased 5 percent. Increased activities of the subsidiaries and diversified operations associated with both engineering services and other project development efforts contributed to this increase. Increases in distribution and transmission expenses were offset by reductions in nuclear and fossil outage costs. In 1995 and 1994, the Company had relatively constant costs associated with work force reduction programs and certain claims that are expected to be non-recurring in nature.

Other operation and maintenance expenses increased at an average annual rate of 6 percent from 1993 to 1995. Costs associated with the enhanced vested retirement benefit program in 1995 as well as other non-recurring costs contributed to this increase in addition to increased activities of the subsidiaries and diversified operations associated with engineering services and other project development efforts. (For additional information on the vested retirement program, see Current Issues, "Resource Optimization," page 38.)

Fuel expense increased at an average annual rate of 1 percent from 1993 to 1995. The increase was due primarily to higher system production requirements, offset by improved nuclear generation.

Net interchange and purchased power expenses decreased from $535 million in 1993 to $468 million in 1995, an average annual decrease of 6 percent. This decrease was primarily the result of lower purchased power costs from the other joint owners not subject to levelization as the other joint owners retained significantly larger portions of their ownership entitlement. In 1996, net interchange and purchased power is expected to decrease again as purchased power costs from the other joint owners continue to decline.

From 1993 to 1995, depreciation and amortization expense decreased at an average annual rate of 4 percent, primarily because the reduction in the amortization of property losses more than offset increased depreciation associated with additional investments. These investments were primarily associated with distribution plant, including investment to support customer growth, commercial operation of 12 units of the Lincoln Combustion Turbine Station, and fossil plant resulting from bringing refurbished units back on-line. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs, "Meeting Future Power Needs," page 38.)

Interest Expense and Other Income

Interest expense increased at an average annual rate of 3 percent from 1993 to 1995, primarily due to long-term debt financing activities in 1994.

Allowance for funds used during construction (AFUDC) and other deferred returns, net of associated taxes, represented 13 percent of earnings for common stock in 1995 compared to 10 percent in 1993. AFUDC and other deferred returns are expected to be less than 11 percent of total earnings during the next three years.

The deferred return, net of associated taxes, on the purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station represented 7 percent of earnings for common stock in 1995, compared to 7 percent in 1994 and 6 percent in 1993. The growth in this return is due

to the increasing cumulative impact of the Company's funding of purchased power costs through 1995, which the Company expects to collect through current rates in future periods. The deferred purchased capacity balance is expected to begin to decline in 1996. (For additional information on purchased capacity levelization, see Capital Needs, "Purchased Capacity Levelization," page 37.)

AFUDC, net of associated taxes, represented 5 percent of earnings for common stock in 1995 compared to 6 percent in 1994 and 4 percent in 1993. The changes were primarily the result of the construction and subsequent commercial operation of the Lincoln Combustion Turbine Station as 12 units were brought on-line at various times during 1995. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs, "Meeting Future Power Needs," page 38.)

Liquidity and Resources

Duke Power Company Rate Matters

The Company's most recent general rate increase requests in the North Carolina and South Carolina retail jurisdictions were filed and approved in 1991. Additionally, Duke Power has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all of Duke Power's regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

Catawba Settlements

The Company and North Carolina Municipal Power Agency Number 1 (NCMPA) and Piedmont Municipal Power Agency (PMPA), two of the four other joint owners of the Catawba Nuclear Station, entered into a settlement in September 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the North Carolina Utilities Commission (NCUC) on January 16, 1996 and the Public Service Commission of South Carolina (PSCSC) on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or the financial position of the Company.

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners, which previously have been approved by the Company's retail regulatory commis[illegible] (For additional information on Catawba joint ownersh[illegible] Note 3 to the Consolidated Financial Statements.) In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years will conform to the settlement agreements, which were approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

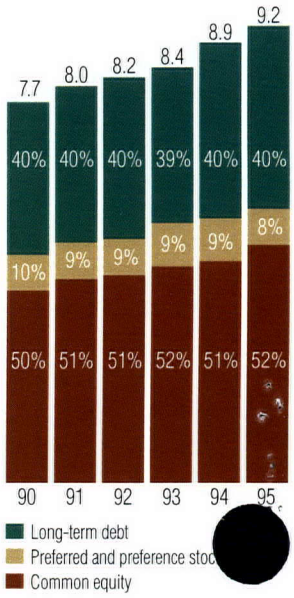
Cash From Operations

Consolidated net cash provided by operating activities in 1995 accounted for 81 percent of total cash from operating, financing and investing activities compared with 67 percent in 1994 and 46 percent in 1993. When 1993 and 1995 refinancing activities are excluded, substantially all of the Company's capital needs were met by cash generated from operating activities. Refinancing activities were insignif[illegible]nt in 1994.

Financing and Investing Activities

The Company's consolidated capital structure at year-end 1995, including subsidiary long-term debt, was 52 percent common equity, 40 percent long-term debt and 8 percent preferred stock. This structure is consistent with the Company's target to maintain a double-A credit rating. As of December 31, 1995, Duke Power's bonds were rated "AA" by Fitch Investors Service, "Aa2" by Moody's Investors Service, and "AA-" by Standard & Poor's Group and Duff & Phelps.

Capital Structure
Billions of dollars



The Company had total credit facilities of $669.9 million and $440.0 million as of December 31, 1995 and 1994, respectively. The Company had unused credit facilities of $440.6 million and $259.9 million as of December 31, 1995 and 1994, respectively.

In response to favorable market conditions in 1993, the Company issued $1.5 billion in long-term debt and $220 million in preferred stock, most of which was used to retire higher cost debt and preferred stock. In 1995, the Company issued $178 million of long-term debt, of

which $72 million was used to retire higher cost long-term debt. The Company also retired $96 million of preferred stock and $80 million of long-term debt in 1995.

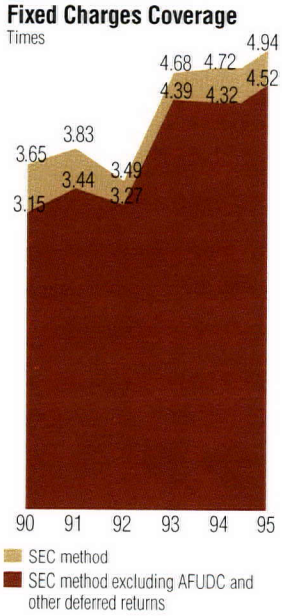
In order to obtain variable rate financing at an attractive [illegible] the Company entered into interest rate swap agreements associated with the November 29, 1994 issuance of $200 million aggregate principal amount of its First and Refunding Mortgage Bonds 8% Series B due 1999 and the August 21, 1995 issuance of $100 million aggregate principal amount of its First and Refunding Mortgage Bonds 7 1/2% Series B due 2025. The interest rate swaps are reset quarterly based upon the three-month London Interbank Offered Rate (LIBOR). As a result of the interest rate swap contracts, interest expense is recognized at the weighted average rate for the year tied to the LIBOR rate. The weighted average rates at December 31, 1995 and 1994 were 6.14% and 5.95%, respectively, for the 8% Series B due 1999 and 7.06% in 1995 for the 7 1/2% Series B due 2025.

The Company has also entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Japanese yen associated with various steam generator purchase contracts. The hedge transaction with a notional amount of approximately $25 million at December 31, 1994, was fully liquidated by November 1995. The Company recorded any gains or losses associated with the hedge as an adjustment to the capitalized cost of the steam generators.

Duke Energy Group, Inc. has entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Chilean peso associated with expected equity contributions over the next two years to a joint venture. The hedge transaction had a notional amount of approximately $17 million at December 31, 1995. Duke Energy Group, Inc. records gains or losses associated with the hedge as an adjustment to investments in joint ventures.

Duke Power's embedded cost of long-term debt, excluding debt of subsidiaries, was 7.94 percent for 1995 compared to 7.98 percent in 1994 and 8.01 percent in 1993. The embedded cost of preferred stock was 7.06 percent in 1995 compared to 6.99 percent in 1994 and 6.76 percent in 1993. The decreases in the embedded cost of long-term debt are primarily the result of the Company's refinancing activities and the resulting lower-cost debt. The increase in the embedded cost of preferred stock from 1993 to 1995 reflects the impact of increased adjustable dividend rates on a certain series of preferred stock and the retirement of preferred stock in 1995.

Fixed Charges Coverage
Times



Fixed Charges Coverage

Consolidated fixed charges coverage using the SEC method increased to 4.94 times for 1995 compared [illegible]72 and 4.68 times in 1994 [illegible]993, respectively. Coverage increased primarily because of higher earnings. Consolidated fixed charges coverage, excluding AFUDC and other deferred returns, was 4.52 times for 1995 compared with 4.32 in 1994 and 4.39 in 1993 and the Company goal of 3.5 times. Coverage was higher in 1995 than 1994 and 1993 as a result of increased earnings excluding AFUDC and other deferred returns.

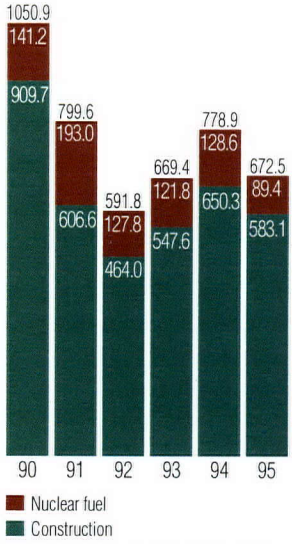
Capital Needs

Property Additions and Retirements

Additions to property and nuclear fuel of $794 million and retirements of $288 million resulted in an increase in gross plant of $506 million in 1995.

Since January 1, 1993, additions to property and nuclear fuel of $2.4 billion and retirements of $864 million have resulted in an increase in gross plant of $1.5 billion.

Duke Power Construction Costs* Millions of dollars



*Includes AFUDC and excludes NP&L and Duke Power's other subsidiaries.

Construction Expenditures

Plant construction costs for generating facilities supporting Duke Power electric operations, including AFUDC, increased from $182 million in 1993 to $281 million in 1995, primarily because of construction of the Lincoln Combustion Turbine Station and the steam generator replacement project. (For more information, see Capital Needs, "Meeting Future Power Needs," page 38 and Current Issues, "Stress Corrosion Cracking," page 39.) Construction costs for distribution plant, including AFUDC, decreased from $240 million in 1993 to $221 million in 1995.

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including AFUDC, are $2.3 billion and $661 million, respectively, for 1996 through 2000. These construction expenditures are primarily for distribution and production related activities representing $997 million and $774 million, respectively. These projections are subject to periodic reviews and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

Projected capital expenditures of subsidiaries and diversified activities are $1.0 billion for 1996 through 2000 of which a significant portion is for real estate development. These projections are subject to periodic review and revision and may vary significantly as the business plans of the Associated Enterprises Group evolve to meet the opportunity presented by its markets.

For 1996 through 2000, the Company anticipates substantially funding its projected construction and capital expenditures through the internal generation of funds.

Purchased Capacity Levelization

The rates established in Duke Power's electric retail jurisdictions permit recovery of its investment in both units of the Catawba Nuclear Station and the costs associated with contractual purchases of capacity from the other joint owners of the Catawba

Nuclear Station. The contracts relating to the sales of portions of the station obligate the Company to purchase a declining amount of capacity from the other joint owners. In the North Carolina retail jurisdiction, regulatory treatment of these contracts provides revenue for recovery of the capital costs and the fixed operating and maintenance costs of purchased capacity on a levelized basis. In the South Carolina retail jurisdiction, revenues are provided for the recovery of the capital costs of purchased capacity on a levelized basis, while current rates include recovery of fixed operating and maintenance expenses.

Such rate treatments require the Company to fund portions of the purchased capacity payments until these costs, including returns, are recovered at a later date. The Company recovers the accumulated costs and returns when the sum of the declining purchased capacity payments and accrual of returns for the current period drop below the levelized revenues. In the North Carolina retail jurisdiction, and wholesale jurisdiction regulated by the Federal Energy Regulatory Commission (FERC), purchased capacity payments and the accrual of deferred returns continue to exceed levelized revenues. However, in 1996, the levelized revenues are expected to exceed the purchased capacity payments and accrual of deferred returns. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments and accrual of deferred returns. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups.

Meeting Future Power Needs

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

The Company is constructing a combustion turbine facility in Lincoln County, North Carolina. The Lincoln Combustion Turbine Station, designed to provide capacity at periods of peak demand, will consist of 16 combustion turbines with a total generating capacity of 1,200 megawatts. The estimated total cost of the project is approximately $400 million. Units 1 through 12 began commercial operation during 1995 and the remaining four units are scheduled to begin commercial operation in 1996.

In 1995, the Company issued two requests for proposals (RFP) to solicit competitive bids for its future electric generating capacity resources. The short-term RFP could provide options for up to 675 megawatts of capacity with terms of 1 to 4 years. The long-term RFP solicits bids to provide up to 300 megawatts of purchased power to be available beginning in 1998 or 1999, for contract periods of between 5 and 20 years in duration. The Company has evaluated a total of 16 proposals received for both the short-term RFP and the long-term RFP and has begun negotiation with the bidders with the best proposals. Contracts are expected to be awarded in May 1996.

The purchase of capacity and energy is also an integral part of meeting future power needs. As of January 1, 1996, the Company has 300 megawatts of firm purchased capacity from other generators of electricity under contract, including 62 megawatts from qualifying facilities.

Demand-side management programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The Company ultimately expects recovery through rates of associated deferred costs, not to exceed $75 million including deferred returns in the North Carolina retail jurisdiction. The annual costs deferred, including the return, were approximately $16 million and $11 million in North Carolina and South Carolina, respectively, in 1995 and $15 million and $10 million in North Carolina and South Carolina, respectively, in 1994. As of December 31, 1995, the balance of deferred demand-side management costs as presented on the Consolidated Balance Sheets in "Other deferred debits" is $58 million and $38 million in North Carolina and South Carolina, respectively.

Current Issues

While the Company improved its financial performance in 1995 compared to 1994, its ability to maintain and improve its current level of earnings will depend on several factors. As industry becomes increasingly competitive, the Company's ability to control costs will be an important factor in maintaining a pricing structure that is both attractive to customers and profitable to the Company. Wheeling of third party energy to a retail customer is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states regarding retail competition which could result in changes in the industry. (For additional information on competition, see Current Issues, "Competition," page 40.) Management cannot predict the outcome of these matters and their impact, if any, on the Company's future financial position and results of operation. The Company is focusing on providing competitive prices to its industrial customers, as well as to wholesale customers who have access to alternative sources of energy. Other significant factors impacting the Company's future earnings levels include continued economic growth in the Piedmont Carolinas, the success of the Company's subsidiaries and diversified activities, and the outcomes of various legislative and regulatory actions.

Resource Optimization. The Company has been engaged in a concentrated effort to more efficiently and effectively use its resources through better work practices. In 1995, the Company offered to certain employees an Enhanced Vested Benefits program (EVB) which gave targeted employees, who left the Company, an enhanced vested retirement package and the Company's standard severance pay based on years of service. This program will result in the departure of approximately 900 employees by the end of the first quarter of 1996. During 1994,

the Company offered an Enhanced Voluntary Separation program (EVS) which gave most employees the option of leaving the Company for a lump-sum payment and the Company's [illegible]ard severance pay based on years of service. This program [illegible]d in the departure of approximately 1,300 employees in 1994. Implementing various efficiency practices has resulted in streamlined workflows and provided the opportunity for work force reduction programs such as EVB and EVS. The number of full-time employees has decreased from 19,945 at year-end 1990 to 17,121 at year-end 1995.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Such estimates presume each unit will be decommissioned as soon as possible following the end of its license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 - 2013, Oconee 3 - 2014; McGuire 1 - 2021, McGuire 2 - 2023; and Catawba 1 - 2024, Catawba 2 - 2026.

The Nuclear Regulatory Commission issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a [illegible]r unit subject to radioactive contamination. In addition [illegible]e required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1995, the Company expensed approximately $56 million, which was contributed to the external funds, and accrued an additional $1 million to the internal reserve. The balance of the external funds as of December 31, 1995, was $273 million. The balance of the internal reserve as of December 31, 1995, was $206 million and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets.

Both the NCUC and the PSCSC have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

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

The Clean Air Act Amendments of 1990. The Clean Air Act Amendments of 1990 require a two-phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national objective of clean air in the most cost-effective manner and has already reduced emissions through the use of low-sulfur coal in its fossil plants, efficient plant operations and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. To meet the Phase II requirements by 2000, the Company's current strategy includes the use of lower sulfur coal, emission allowance purchases, low nitrogen oxide burners and emission monitoring equipment. A one-time cost associated with bringing the Company into compliance with the Act could range from $94 million to $320 million. Additional operating expenses of approximately $55 million will be incurred for fuel premiums and emission allowance purchases each year after 2000. This strategy is contingent upon developments in the emissions allowance market, lower sulfur coal fuel premiums, future regulatory and legislative actions, and advances in clean air technology.

Stress Corrosion Cracking. Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company is planning for the replacement of steam generators at three units that have experienced SCC and has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. The current schedule for completion of the effort is as follows: Catawba Unit 1 - 1996, McGuire Unit 1 - 1997 and McGuire Unit 2 - 1997. The order of replacement is subject to change based on operational and project circumstances. The Catawba Unit 2 steam generators have not been scheduled for replacement. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $170 million, excluding the cost of replacement power and the reimbursement of applicable costs by the other joint owners of Catawba Unit 1. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and

Catawba stations and on behalf of the other joint owners of the Catawba Station, began a legal action in 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba stations steam generators that were defective in design, workmanship, and materials, requiring replacement well short of their stated design life. The lawsuit was settled in 1994. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the Company's results of operations or financial position.

Competition. The Energy Policy Act of 1992 (EPACT) is a major driver towards a more competitive market for wholesale sales of power. EPACT reformed provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, EPACT allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. In addition, EPACT permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that independent suppliers can sell at wholesale to customers wherever located. It does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

The FERC, responsible in large measure for implementation of the EPACT, has moved vigorously to implement its mandate, interpreting the statute broadly in issuing orders for third-party transmission service and issuing a number of rules of general applicability. The FERC in late March of 1995 issued a Notice of Proposed Rulemaking (the "NOPR") in which it announced its intent to impose a final rule, applicable to all electric utilities subject to its jurisdiction, which will require all such utilities to adopt open-access transmission tariffs containing identical terms and conditions. The FERC should issue its final rule in 1996.

Open transmission access for wholesale customers as contemplated by the FERC's NOPR would provide energy suppliers, including the Company, with opportunities to sell and deliver capacity and energy at market-based prices. Engaging in such transactions could result in improved utilization of the Company's existing assets. In addition, such access would provide another supply option through which the Company can buy capacity and energy at attractive rates, influencing its competitive price position. However, sales to existing wholesale customers of the Company could be impacted by open access as contemplated by the NOPR either due to competitive pressure on the wholesale price of electricity, or the potential loss of sales as wholesale customers seek other options to meet their capacity and energy requirements at market-based prices. Wholesale sales, excluding transactions with other utilities, represented approximately 6.7 percent of the Company's total kilowatt-hour sales in 1995. Supplemental sales to the other joint owners of the Catawba Nuclear Station comprised the majority of such sales. Such supplemental sales will be declining in 1996 as a result of the retention of significantly larger portions of ownership entitlement by the other joint owners. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

In early 1995, prior to issuance of the FERC's NOP[illegible] Company and certain of its affiliates filed three applications with the FERC, all of which are designed to enable effective participation in the competitive environment of the changing electric utility industry. Duke Power filed an application for permission to sell at market-based rates up to 2,500 megawatts of capacity and energy from its own assets. Two of the Company's affiliates, Duke Energy Marketing Corporation (DEMC) and Duke/Louis Dreyfus L.L.C. (D/LD), filed applications with the FERC to become power marketers. All of the applications were supported by transmission tariffs which establish the rates, terms and conditions for transmission service to third parties on the Company's transmission system.

Late in 1995, the FERC granted the applications of Duke, DEMC, and D/LD; accepted Duke's transmission tariffs; and ordered a hearing on the rates to be charged for service under those tariffs. The terms and conditions of service are subject to the outcome of the FERC's final rule, and the rates are subject to the outcome of hearings before the FERC.

Wheeling of third party energy to a retail customer is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states regarding retail competition which could result in changes in the industry.

Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of pro[illegible] electric power to its retail and wholesale customers. If cost-[illegible] regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced and utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require affected utilities to write off their associated regulatory assets. The regulatory assets of the Company are classified as "Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

Commitments and Contingencies. The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which may involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of [illegible] proceedings will not have a material adverse effect on the [illegible] of operations or the financial position of the Company.

Subsidiaries and Diversified Operations. The Company continues to aggressively pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Among the Company's current industry pursuits are: ownership of electric power facilities, power marketing, real estate, communications, engineering consulting and various energy services. Although these opportunities are primarily concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. The Company undertakes a continuous evaluation of the various lines of business it may enter or exit, with the objectives of enhancing shareholder value and managing any associated risk.

Domestically, non-electric property of the Company's subsidiaries and diversified activities was $335 million and $286 million at December 31, 1995 and 1994, respectively. The Company had equity investments in joint ventures, which own assets within the United States, of $58 million and $14 million at December 31, 1995 and 1994, respectively.

Internationally, the Company had equity investments in joint ventures, which own generation and transmission facilities, of $105 million and $94 million at December 31, 1995 and 1994, respectively. Additionally, the Company, through its non-regulated subsidiaries, had loaned $23 million to certain of these joint ventures at December 31, 1995.

The Company's subsidiaries and diversified activities contributed $54 million to net income in 1995 compared with $52 million in 1994 and $22 million in 1993. From 1993 to 1995, increased developed lot and land sales, and engineering services and construction fees generated additional income. These increases were offset by personal communications services joint venture losses in 1995. Additionally, a one-time gain on the sale of an investment in preferred stock of an independent power development company in 1994 contributed to the increase in diversified income from 1993 to 1994.

SELECTED FINANCIAL DATA

	1995	1994	1993	1992	1991
Condensed consolidated statements of income (thousands)					
Operating revenues	$ 4,676,684	$ 4,488,913	$ 4,466,233	$ 4,122,503	$ 3,9[illegible]
Operating expenses	3,327,633	3,309,087	3,258,422	3,087,422	2,968,239
Operating income	1,349,051	1,179,826	1,207,811	1,035,081	994,366
Interest expense and other income	(168,072)	(143,931)	(171,419)	(223,028)	(117,725)
Income before income taxes	1,180,979	1,035,895	1,036,392	812,053	876,641
Income taxes	466,441	397,019	409,977	303,970	293,018
Net income	714,538	638,876	626,415	508,083	583,623
Dividends on preferred and preference stock	48,903	49,724	52,429	56,407	54,683
Earnings for common stock	$ 665,635	$ 589,152	$ 573,986	$ 451,676	$ 528,940
Common stock data					
Shares of common stock — year-end (thousands)	204,859	204,859	204,859	204,859	204,699
— average (thousands)	204,859	204,859	204,859	204,819	203,431
Per share of common stock					
Earnings	$3.25	$2.88	$2.80	$2.21	$2.60
Dividends	$2.00	$1.92	$1.84	$1.76	$1.68
Book value — year-end	$23.36	$22.13	$21.17	$20.26	$19.86
Market price — high-low	$47⅞-37⅜	$43-32⅞	$44⅞-35⅜	$37½-31⅜	$35-26¾
— year-end	$47⅜	$38⅛	$42⅜	$36⅛	$35
Balance sheet data (thousands)					
Total assets	$13,358,484	$12,862,228	$12,293,605	$11,012,795	$10,617,552
Long-term debt	$ 3,711,405	$ 3,567,122	$ 3,285,397	$ 3,288,111	$ 3,235,492
Preferred stock with sinking fund requirements	$ 234,000	$ 279,500	$ 281,000	$ 279,519	$ 228,650
Electric and other statistics (a)					
Kilowatt-hour sales (millions)					
Residential	19,669	18,870	19,465	17,789	[illegible]
General service	18,160	17,289	16,904	15,818	[illegible]
Industrial	29,782	29,290	28,198	27,041	26,270
Other energy and wholesale (b)	8,330	10,274	11,337	10,360	10,132
Total kilowatt-hour sales billed	75,941	75,723	75,904	71,008	69,906
Unbilled kilowatt-hour sales	796	(160)	154	34	(19)
Total kilowatt-hour sales	76,737	75,563	76,058	71,042	69,887
Average revenue per billed KWH					
Residential	7.33¢	7.31¢	7.32¢	7.38¢	7.10¢
General service	5.93¢	5.96¢	6.00¢	6.10¢	5.91¢
Industrial	4.23¢	4.24¢	4.31¢	4.36¢	4.35¢
Sources of energy (millions of KWH)					
Generated — Coal	32,389	32,714	34,097	28,999	26,455
— Nuclear (c)	39,836	35,587	34,390	33,925	37,048
— Hydro (d)	1,685	1,460	1,582	1,834	1,545
— Oil and gas (e)	255	35	43	5	7
Total generation	74,165	69,796	70,112	64,763	65,055
Net interchange and purchased power	1,175	1,276	1,750	1,403	587
Total output	75,340	71,072	71,862	66,166	65,642
Purchases from other Catawba joint owners	6,070	9,046	8,810	9,466	8,525
Total sources of energy	81,410	80,118	80,672	75,632	74,167
Line loss and Company usage	4,673	4,555	4,614	4,590	4,280
Total kilowatt-hour sales	76,737	75,563	76,058	71,042	69,887
System average heat rate (c)	9,867	9,863	9,872	9,929	9,944
System load factor (c)	57.6%	57.7%	59.4%	58.9%	[illegible]

	1995	1994	1993	1992	1991
Electric operating results (thousands) (a)					
Electric revenues	$ 4,422,438	$ 4,279,329	$ 4,281,876	$ 3,961,484	$ 3,816,960
Electric expenses					
Operation					
Fuel used in electric generation	744,226	705,019	732,246	659,593	657,725
Net interchange and purchased power	467,264	553,802	535,033	540,840	545,840
Wages, benefits and materials	805,665	781,842	701,994	636,729	622,121
Maintenance of plant facilities	415,610	429,617	375,457	403,162	354,679
Depreciation and amortization	446,284	450,215	488,441	491,339	431,624
General taxes	243,985	239,714	231,680	215,493	204,688
Total operating expenses	3,123,034	3,160,209	3,064,851	2,947,156	2,816,677
Operating income	1,299,404	1,119,120	1,217,025	1,014,328	1,000,283
Income taxes	438,825	361,653	402,960	289,633	293,460
Electric operating income	$ 860,579	$ 757,467	$ 814,065	$ 724,695	$ 706,823

(a) Excludes Nantahala Power and Light Company operations.
(b) Includes sales to Nantahala Power and Light Company.
(c) Includes 12.5% of Catawba generation.
(d) 1991 includes KWH of the Bad Creek Hydroelectric Station prior to commercial operation.
(e) 1995 includes KWH of the Lincoln Combustion Turbine Station prior to commercial operation.

Quarterly Financial Data

Dollars in Thousands (except per-share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
1995 by quarter					
Operating revenues	$1,111,065	$1,052,403	$1,379,978	$1,133,238	$4,676,684
Operating income	$ 369,414	$ 263,876	$ 504,507	$ 211,254	$1,349,051
Net income	$ 201,276	$ 137,523	$ 285,200	$ 90,539	$ 714,538
Earnings per share	$0.92	$0.61	$1.33	$0.39	$3.25
1994 by quarter					
Operating revenues	$1,099,002	$1,083,310	$1,272,525	$1,034,076	$4,488,913
Operating income	$ 326,584	$ 242,419	$ 430,861	$ 179,962	$1,179,826
Net income	$ 173,617	$ 128,002	$ 243,741	$ 93,516	$ 638,876
Earnings per share	$0.79	$0.56	$1.13	$0.40	$2.88

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

Stock Market Information

The Company had 129,265 holders of record of common stock as of December 31, 1995, and 129,637 holders as of December 31, 1994. During 1995, approximately 59,641,300 shares of common stock were traded, compared with 75,971,600 during the previous year. A significant portion of the number of shares traded in 1994 was due to the public offering of 14 million shares of stock by The Duke Endowment in March 1994. 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		Dividends Per Share	Stock Price Range High	Stock Price Range Low
1995 by quarter				**1994 by quarter**			
Fourth	$0.51	$47⅞	$43⅛	Fourth	$0.49	$42⅛	$38
Third	0.51	43¾	40	Third	0.49	39⅞	35½
Second	0.49	42¾	38¼	Second	0.47	37	32⅞
First	0.49	40¾	37⅜	First	0.47	43	35¾

SUBSIDIARIES AND DIVERSIFIED ACTIVITIES HIGHLIGHTS

During 1994, the Company reorganized, placing all its subsidiaries and diversified activities into the Associated Enterprises Group (AEG). AEG includes the following:

- **Church Street Capital Corp.** (CSCC) manages investment funds, serves as the parent company and provides equity funding and credit enhancement for the non-electric operating subsidiaries. CSCC investment highlights are as follows (dollars in thousands):

  Short-term investments and marketable securities

1995	1994	1993
$76,300	$170,642	$155,871

  Investment income (after tax) (a)

1995	1994	1993
$ 4,783	$ 7,562	$ 3,548

- **Crescent Resources, Inc.** is engaged in real estate development and forest management.
- **Duke Energy Group, Inc.** develops, owns and manages investments in electric power facilities, both nationally and internationally, and markets electric power and natural gas.
- **Duke Engineering & Services, Inc.** markets engineering, construction, quality assurance, consulting and other engineering-related services for facilities other than coal-generating plants, both nationally and internationally.
- **Duke/Fluor Daniel**, a joint venture with Fluor Daniel, Inc., provides engineering, construction, and support of operating and maintenance activities, primarily for coal-fired generating plants, both nationally and internationally.
- **Duke Merchandising** sells and services quality appliances and electronics primarily to Duke Power customers.
- **DukeNet Communications, Inc.** develops and manages communication systems.
- **Duke Water Operations** serves areas of Anderson, South Carolina, and Rutherfordton, North Carolina.
- **Nantahala Power and Light Company** provides electric service to a five-county area in western North Carolina by its operation of eleven hydroelectric stations and purchase of supplemental power.

Operating Results

Dollars in Thousands — Year ended December 31,	1995	1994	1993
Operating revenues			
Crescent Resources, Inc.	$ 85,361	$ 64,724	$ 46,784
Duke Energy Group, Inc. (b)	10,017	9,478	6,033
Nantahala Power and Light Company (c)	62,510	68,595	67,142
All Other Business Units (d)	141,337	109,932	106,340
Total Associated Enterprises Group	$299,225	$252,729	$2[illegible]
Operating income			
Crescent Resources, Inc.	$ 63,973	$ 46,236	$ 30,004
Duke Energy Group, Inc.	(1,422)	(1,035)	(2,929)
Nantahala Power and Light Company	9,262	12,224	8,844
All Other Business Units (d)	20,407	15,506	1,939
Total Associated Enterprises Group	$ 92,220	$ 72,931	$ 37,858
Net income			
Crescent Resources, Inc.	$ 35,500	$ 26,525	$ 16,327
Duke Energy Group, Inc. (e)	170	5,749	(1,949)
Nantahala Power and Light Company	4,037	6,169	4,261
All Other Business Units (d)	14,550	13,593	2,876
Total Associated Enterprises Group	$ 54,257	$ 52,036	$ 21,515

Financial Position

Dollars in Thousands — December 31,	1995	1994	1993
Total assets			
Crescent Resources, Inc.	$381,073	$294,175	$219,206
Duke Energy Group, Inc. (f)	149,391	110,656	144,499
Nantahala Power and Light Company	144,069	125,883	107,872
All Other Business Units (d)	283,774	279,430	265,977
Total Associated Enterprises Group	$958,307	$810,144	$737,554
Total liabilities			
Crescent Resources, Inc.	$185,996	$134,574	$ 8[illegible]
Duke Energy Group, Inc.	9,783	4,672	[illegible]
Nantahala Power and Light Company	86,691	72,542	60,[illegible]00
All Other Business Units (d)	43,498	22,312	30,902
Total Associated Enterprises Group	$325,968	$234,100	$209,590

Cash Flows

Dollars in Thousands — Year ended December 31,	1995	1994	1993
Cash provided by (used in) operating activities			
Crescent Resources, Inc.	$ 40,144	$ 37,691	$ 36,254
Duke Energy Group, Inc.	(3,521)	(6,614)	(1,438)
Nantahala Power and Light Company	8,419	12,817	14,869
All Other Business Units (d)	1,769	10,589	8,795
Total Associated Enterprises Group	$ 46,811	$ 54,483	$ 58,480
Cash provided by investing activities			
Crescent Resources, Inc.	$ 5,910	$ 2,524	$ 1,310
Duke Energy Group, Inc. (g)	14,253	40,740	28,785
Nantahala Power and Light Company	—	—	—
All Other Business Units (h)	97,793	5,100	21,377
Total Associated Enterprises Group	$117,956	$ 48,364	$ 51,472
Cash used in investing activities			
Crescent Resources, Inc.	$ 84,603	$ 78,689	$ 43,444
Duke Energy Group, Inc.	44,776	19,575	116,498
Nantahala Power and Light Company	23,944	23,989	19,254
All Other Business Units (i)	66,768	18,500	1,450
Total Associated Enterprises Group	$220,091	$140,753	$180,646
Cash provided by (used in) financing activities (j)			
Crescent Resources, Inc. (k)	$ 38,521	$ 37,589	$ 945
Duke Energy Group, Inc. (l)	—	—	—
Nantahala Power and Light Company	15,536	10,896	3,206
All Other Business Units (m)	5,302	(6,993)	71,537
Total Associated Enterprises Group	$ 59,359	$ 41,492	$ 75,688

Other Information

December 31,	1995	1994	1993
Full-time employees at year-end			
Crescent Resources, Inc.	94	89	77
Duke Energy Group, Inc.	43	35	24
Nantahala Power and Light Company	182	184	194
All Other Business Units	1,036	703	755
Total Associated Enterprises Group	1,355	1,011	1,050

(a) Earnings for 1995, 1994 and 1993 exclude elimination of intercompany profits of $59,000, $49,000 and $509,000, respectively.
(b) Includes Duke Energy Group, Inc.'s allocable share of net income from joint ventures. (See Note 11.)
(c) Nantahala Power and Light Company's Operating revenues include revenues from the sale of electricity to Duke Power of $1,205,000, $12,131,000 and $13,683,000 for 1995, 1994 and 1993, respectively.
(d) All Other Business Units amounts include Associated Enterprises Group intercompany eliminations.
(e) 1994 includes a gain of $4,800,000, after tax, from the sale of preferred stock.
(f) Includes Duke Energy Group, Inc.'s investments in joint ventures. (See Note 11.)
(g) 1994 includes proceeds from the sale of preferred stock of $32,468,000 and debt securities of $3,360,000. 1993 includes proceeds from the sale of debt securities of $19,654,000.
(h) 1995 and 1993 include the net change in short-term investments for the period of $56,392,000 and $20,653,000, respectively. Also, 1995 includes proceeds from the sale of a [illegible]nd capture program of $40,953,000.
([illegible]) [illegible] includes the net change in short-term investments for the period of $12,060,000.
(j) Excludes capital infusion and return of capital transactions between parent, Church Street Capital Corp., and its subsidiaries.
(k) 1993 excludes capital infusion from parent, Church Street Capital Corp., of $6,000,000.
(l) 1995 and 1993 exclude net capital infusions from parent, Church Street Capital Corp., of $33,455,000 and $91,864,000, respectively. 1994 excludes net return of capital to Church Street Capital Corp. of $12,100,000.
(m) 1993 includes capital infusion from Duke Power to Church Street Capital Corp. of $75,000,000.

Board of Directors

William H. Grigg
Chairman of the Board and Chief Executive Officer [1, 5, 6]
Duke Power Company
Director since 1972

G. Alex Bernhardt
President, Chief Executive Officer and Director
Bernhardt Furniture Company [4]
Director since 1991

Crandall C. Bowles
Executive Vice President
Springs Industries, Inc. [3, 5]
Director since 1988

Robert J. Brown
Chairman and President
B & C Associates, Inc. [2]
Director since 1994

William A. Coley
President
Associated Enterprises Group [1, 4]
Duke Power Company
Director since 1990

Steve C. Griffith, Jr.
Vice Chairman of the Board and General Counsel [1]
Duke Power Company
Director since 1982

Paul H. Henson
Chairman
Kansas City Southern Industries, Inc. [3, 4, 6]
Director since 1976

George Dean Johnson, Jr.
President and Chief Executive Officer
Extended Stay America [5, 6]
Director since 1986

James V. Johnson
Retired Vice Chairman and Director, Public Affairs
Coca-Cola Bottling Co. Consolidated [2]
Director since 1982

W. W. Johnson
Chairman of the Executive Committee
NationsBank Corporation [5, 6]
Director since 1984

A. Max Lennon
President
Mars Hill College [2]
Director since 1988

James G. Martin
Vice President, Development and Chairman
Research Development Board, Charlotte-Mecklenburg Hospital Authority [4]
Director since 1994

Buck Mickel
Retired Vice Chairman
Fluor Corporation [3, 4]
Director since 1976

Richard B. Priory
President and Chief Operating Officer [1, 5]
Duke Power Company
Director since 1990

Russell M. Robin
Attorney
Robinson, Bradshaw & Hinson, P.A. [2]
Director since 1995

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 the Company's internal accounting control and internal audit programs and making necessary recommendations to the Board as appropriate.

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

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.

OFFICERS

William H. Grigg
Chairman of the Board and Chief Executive Officer

Steve C. Griffith, Jr.
Vice Chairman of the Board and General Counsel

William A. Coley
President
Associated Enterprises Group

Richard B. Priory
President and Chief Operating Officer

Donald H. Denton, Jr.
Senior Vice President and Chief Planning Officer

Jim R. Hicks
Senior Vice President, Customer Operations

Richard J. Osborne
Senior Vice President and Chief Financial Officer

Ruth G. Shaw
Senior Vice President, Corporate Resources and Chief Administrative Officer

Michael S. Tuckman
Senior Vice President, Nuclear Generation

Sue A. Becht
Treasurer

Jeffrey L. Boyer
Controller

Sharon A. Decker
Vice President, Communications and Community Relations

Excell O. Ferrell, III
Vice President, Deliver Products & Services

Ronald L. Gibson
Vice President, Develop Customer Operations Plans & Strategies

James E. Grogan
Vice President, Electric System Support

James W. Hampton
Vice President, Oconee Nuclear Site

Donald E. Hatley
Vice President, Public Affairs

David L. Hauser
Vice President, Procurement, Services and Materials

J. William Hillhouse, Jr.
Vice President, Central Region

James D. Hinton
Vice President, Power Delivery

John P. Holland
Vice President, Northwestern Region

Robert S. Lilien
Vice President and Tax Counsel

John F. Lomax
Vice President, Business & Community Relations

David H. Maner
Vice President, Northern Region

William R. McCollum, Jr.
Vice President, Catawba Nuclear Site

Maurice D. McIntosh
Vice President, Fossil and Hydro Generation

Ted C. McMeekin
Vice President, McGuire Nuclear Site

Barbara B. Orr
Vice President, Southern Region

William F. Reinke
Vice President, System Planning and Operating

Christopher C. Rolfe
Vice President, Organization Effectiveness

Ellen T. Ruff
Secretary and Deputy General Counsel

Cecil O. Smith, Jr.
Vice President, Information Technology Services

William R. Stimart
Vice President, Rates and Regulatory Affairs

Virginia M. Britton
Assistant Controller

Carol D. Denton
Assistant Secretary

S. L. Love
Assistant Treasurer

Robert T. Lucas III
Assistant Secretary

Phyllis T. Simpson
Assistant Secretary

Associated Enterprises Group

Steven M. Kessler
President, Duke Merchandising

John F. Norris, Jr.
President and Chief Executive Officer
Duke Engineering & Services, Inc.

Richard J. Osborne
President
Church Street Capital Corp.

Richard C. Ranson
Chairman and Chief Executive Officer
Crescent Resources, Inc.

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

Marion H. Smith, Jr.
President and Chief Executive Officer
DukeNet Communications, Inc.

N. E. Tucker, Jr.
President and Chairman of the Board
Nantahala Power and Light Company

M. Rhem Wooten, Jr.
President
Duke Energy Group, Inc.

Retiring Officer

The following officer has retired:

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

GLOSSARY

Annual Total Return to Shareholders
Annualized change in value of stock price plus dividends.

Base Load
Duke's "24-hour-a-day" load, or the amount of electric power delivered or needed at the lowest point of demand during the day. At Duke Power, base load is met primarily by the Company's nuclear-fueled generating plants.

Business Unit
A unit within Duke Power that is clearly responsible for controlling its own profitability. There are ten business units within Duke Power.

Dividend Payout Ratio
The percentage 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.

Earnings Coverage of Fixed Charges
Calculated by dividing earnings before taxes and interest expense by interest expense. This is an indicator of credit quality commonly used by bond investors.

General Service Customers
Retail customers of Duke Power other than residential or industrial customers, such as churches, restaurants, schools, and businesses.

Indicated Annual Dividend
The most recently declared quarterly dividend rate per 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, combustion turbine units, and purchased power.

Power Marketer
A power marketer buys and sells electricity in various blocks of capacity and energy. A marketer takes title to the power, as opposed to a power broker who receives a fee for matching buyers and sellers.

Return on Average Common Equity
A measure of profitability calculated by dividing annual earnings for common stock by average common stock equity.

Steam Generators
In a nuclear power plant, large heat exchangers that transfer energy from water heated in one system to create steam from water in another system.

INVESTOR INFORMATION

Corporate Headquarters

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

Annual Meeting

The 1996 Annual Meeting of Duke Power Shareholders will be:

Date: Thursday, April 25, 1996
Time: 10:00 a.m.
Place: Peace Center for the Performing Arts
101 West Broad Street
Greenville, S.C.

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

InvestorLine, our automated telephone system, offers the following information:

Mailing Address
Closing Stock Price
Account Information
Stock Transfer Instructions

Just call our current 800 phone number. A representative can assist you directly by pressing the star key (*) at any time.

Visit our home page on the World Wide Web at http://www.dukepower.com.

Financial Publications

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

1995 Annual Report on Form 10-K as filed with the Securities and Exchange Commission

1995 Statistical Supplement and Financial Forecast

Audiotape recording of excerpts from the 1995 Annual Report to Shareholders

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

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.

The Company's First and Refunding Mortgage Bonds and certain issues of preferred stock are listed on the New York Stock Exchange. Quotations for these issues are listed only when traded.

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. Bank drafts for monthly purchases of common stock as well as a safekeeping option for depositing common stock certificates in the Plan are available.

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 acknowledgment are not acceptable pursuant to applicable regulations.

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

Dividend Payment

Duke Power has paid quarterly cash dividends on its common stock for 69 consecutive years.

Dividends on the Company's common and preferred stock in 1996 are expected to be paid on:

March 18, June 17, September 16, and December 16

Registrar

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

Bond Trustee

Chemical Bank
c/o Texas Commerce Bank
Corporate Trust Services
P.O. Box 2320
Dallas, Texas 75221-2320

If you have any questions regarding your bond account, write to Chemical Bank at the above address or call (800) 648-8380.

Duke Power is an Equal Opportunity Employer.

Recycled/Recyclable

DUKE ENERGY
422 South Church Street
Charlotte, North Carolina
28242-0001

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

[✓] **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
[Fee Required]

For the fiscal year ended December 31, 1995 or

[ ] **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
[No Fee Required]

For the transition period from _____ to _____

Commission file number 1-4928

DUKE POWER COMPANY

(Exact name of registrant as specified in its charter)

North Carolina **(State or other jurisdiction of incorporation or organization)**	56-0205520 **(I.R.S. Employer Identification No.)**
422 South Church Street, Charlotte, North Carolina **(Address of principal executive offices)**	28242-0001 **(Zip Code)**

704-594-0887
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, without par value	New York Stock Exchange, Inc.
Preferred Stock A, par value $25	
7.72%, 1992 Series	New York Stock Exchange, Inc.
6.375%, 1993 Series	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5 3/8% Due 1997	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5 7/8% Due 2001	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 5 7/8% Series C Due 2003	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 1/4% Series B Due 2004	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 3/8% Due 2008	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 5/8% Series B Due 2003	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 3/4% Due 2025	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 6 7/8% Series B Due 2023	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2000	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Series B Due 2000	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2005	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7% Due 2033	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7 3/8% Due 2023	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7 7/8% Due 2024	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8% Series B Due 1999	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8% Due 2004	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8 3/8% Series B Due 2021	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8 5/8% Due 2022	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 8 3/4% Due 2021	New York Stock Exchange, Inc.
First and Refunding Mortgage Bonds, 7 1/2% Series B Due 2025	New York Stock Exchange, Inc.

Securities registered pursuant to Section 12(g) of the Act:

Title of class
Preferred Stock, par value $100

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No _____

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

Estimated aggregate market value of the voting stock held by nonaffiliates of the registrant at March 8, 1996 ..... $9,850,948,807

Number of shares of Common Stock, without par value, outstanding at March 8, 1996 204,859,339

Documents incorporated by reference:

The registrant is incorporating herein by reference certain sections of its proxy statement relating to the 1996 annual meeting of shareholders to provide information required by the following parts of this annual report:

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

DUKE POWER COMPANY
FORM 10-K
ANNUAL REPORT TO
THE SECURITIES AND EXCHANGE COMMISSION
FOR THE YEAR ENDED DECEMBER 31, 1995

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DUKE POWER COMPANY

PART I.

Item 1. *Business.*

Duke Power Company (the Company) is primarily engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas. It is one of the nation's largest investor-owned electric utilities.

The Company is also engaged in a variety of diversified operations, most of which are organized in separate subsidiaries. The Company's subsidiaries and diversified activities are in the Associated Enterprises Group (AEG). AEG includes Church Street Capital Corp.; Crescent Resources, Inc.; Duke Energy Group, Inc.; Duke Engineering & Services, Inc.; Duke/Fluor Daniel; Duke Merchandising; DukeNet Communications, Inc.; Duke Water Operations; and Nantahala Power and Light Company (NP&L). For additional information on subsidiaries and diversified activities, see "Subsidiaries and Diversified Activities" on page 10, "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — Subsidiaries and Diversified Operations" on page 26 and "Subsidiaries and Diversified Activities Highlights" on page 50.

During 1995, the Company's operating revenues, including AEG, were $4.7 billion. The Company's executive offices are located in the Power Building, 422 South Church Street, Charlotte, North Carolina 28242-0001 (Telephone No. 704-594-0887).

Service Area

The Company's service area (excluding NP&L), approximately two-thirds of which lies in North Carolina, covers about 20,000 square miles with an estimated population of 5.0 million and includes a number of cities, of which the largest are Charlotte, Greensboro, Winston-Salem and Durham in North Carolina and Greenville and Spartanburg in South Carolina. The Company supplies electric service directly to approximately 1.8 million residential, commercial and industrial customers in more than 200 cities, towns and unincorporated communities. Electricity is sold at wholesale to incorporated municipalities and to several public and private utilities. In addition, sales are made through contractual agreements to former wholesale municipal or cooperative customers of the Company who had purchased portions of the Catawba Nuclear Station (collectively, the "other Catawba joint owners"). (See "Joint Ownership of Generating Facilities.") NP&L services an additional 53,000 mostly residential customers in five counties in western North Carolina.

The Company's service area is undergoing increasingly diversified industrial development. The textile industry, machinery and equipment manufacturing, and chemical and chemical-related industries are of major significance to the economy of the area. Other industrial activities include rubber and plastic products, paper and allied products, and various other light and heavy manufacturing and service businesses. The largest industry served is the textile industry, which accounted for approximately $494 million of the Company's revenues for 1995, representing 11 percent of electric revenues and 39 percent of industrial revenues.

Energy Requirements and Capability

The following table sets forth the Company's generating capability as of December 31, 1995, its sources of electric energy for 1995 and certain information presently projected for 1996:

Source	Generating Capability — MW(a)(b)(c)		Generation — MWH (thousands)(c)
	Actual December 31, 1995	Projected December 31, 1996	Actual 1995
Coal	7,699	7,699	32,389
Nuclear (d)	5,078	5,078	39,836
Hydro and other	4,166	4,466(e)	1,940
Total	16,943	17,243	74,165
Plus: Purchases from other Catawba joint owners			6,070
Purchased power and net interchange			1,175
Total			81,410

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

(b) Excludes firm purchases and sales. (See "Energy Management and Future Power Needs.")

(c) Excludes NP&L.

(d) Nuclear capability and related generation for 1995 and related projections for 1996 reflect the Company's 12.5% ownership share of the Catawba Nuclear Station. (See "Joint Ownership of Generating Facilities.")

(e) Includes four units of the Lincoln Combustion Turbine Station with generating capacity of 300 MW which were placed into commercial operation in early 1996. (See "Capital Requirements.")

NP&L operates 11 hydroelectric stations with a total capacity of 100 megawatts and also purchases supplemental power. The Company supplies supplemental power to NP&L under the terms of an interconnection agreement approved by the Federal Energy Regulatory Commission (FERC).

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

According to 1994 industry statistics published in 1996, the Company ranked first in the nation in terms of efficiency of its steam-fossil generating system as measured by the conversion of fuel energy to electric energy. Published rankings indicate that individual units at Marshall Steam Station and Belews Creek Steam Station ranked first, third, fourth, fifth, eighth and tenth most efficient in the nation in 1994. The Company's nuclear system continued its tradition of operating efficiency, operating at 90 percent of capacity for 1995, in comparison with the industry's latest available average capacity factor of 74 percent for 1994. The Company's system nuclear capacity factor reflects the Company's 12.5% ownership share of the Catawba Nuclear Station.

The Company normally experiences seasonal peak loads in summer and winter which are relatively in balance. The Company currently forecasts a 1.8 percent compound annual growth in peak load through 2010. An all-time peak load of 15,542 MW occurred on August 14, 1995 during exceptionally warm summer weather. This peak load excludes the portion of the demand of the other joint owners of the Catawba Nuclear Station met by their retained ownership.

Rate Matters

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

The most recent general rate increase requests in the Company's retail jurisdictions were filed and approved in 1991. The Company also filed its most recent general rate increase request within the FERC wholesale jurisdiction in 1991. A negotiated settlement between the Company and the wholesale customers was approved by the FERC in 1992.

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

During 1992, NP&L filed an application for a general rate increase with the NCUC. A general rate increase was approved in June 1993.

Fuel And Purchased Power Cost Adjustment Procedures. Duke Power has procedures in all three of its regulatory jurisdictions to adjust rates for fluctuations in fuel expense. The North Carolina legislature enacted a statute in 1987 assuring the legality of adjustments of past over- and under-recovery of fuel costs in rates. The North Carolina legislature repealed the expiration provision of this statute in March 1995. In the North Carolina retail jurisdiction, a review of fuel costs in rates is required annually and during general rate case proceedings. Fuel costs are reviewed semiannually in the wholesale and South Carolina retail jurisdictions. All jurisdictions allow Duke Power to adjust rates for past over- or under-recovery of fuel costs. Therefore, Duke Power reflects in revenues the difference between actual fuel costs incurred and fuel costs recovered through rates.

Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

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

Energy Management and Future Power Needs

The Company's strategy for meeting customers' present and future energy needs is composed of three components: demand-side resources, purchased power resources and supply-side resources. By utilizing these resources, the Company expects to maintain a reserve margin of approximately 18 to 20 percent of its anticipated peak load requirements through 2000. The Company continues to engage in a comprehensive energy management program as part of its Integrated Resource Plan (IRP). Integrated resource planning is the process used by utilities to evaluate a variety of resources. The goal is to provide adequate and reliable electricity in an environmentally responsible manner through cost-effective power management. The Company files an IRP with the NCUC and the PSCSC once every three years. During each of the intervening years, the Company files a Short Term Action Plan which updates the IRP for any changes in projections for the next three years. The PSCSC issued an order on December 14, 1995 approving the Company's 1995 IRP. On February 20, 1996, the NCUC issued a similar order.

Demand-side management (DSM) programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for DSM programs and allowed the deferral for later recovery of certain DSM costs that exceed the level reflected in rates, including a return on deferred costs. In 1993, the NCUC and the PSCSC issued orders approving "shared savings" mechanisms for accomplishments achieved in the Company's DSM programs, and deferral of such shared savings. The Company ultimately expects recovery through rates of associated deferred costs, not to exceed $75 million including deferred returns in the North Carolina retail jurisdiction. The annual costs deferred, including the return, were approximately $27 million in 1995 and $25 million in 1994. The total costs deferred, including the return, are $58 million and $38 million in North Carolina and South Carolina, respectively.

The purchase of capacity and energy is an integral part of meeting future power needs. As of December 31, 1995, the Company had under contract 300 MW of capacity from other generators of electricity, including 62 MW from qualifying facilities. In 1995, the Company issued two requests for proposals (RFP) to solicit competitive bids for its future electric generating capacity resources. The short-term RFP could provide options for up to 675 megawatts of capacity with terms of 1 to 4 years. The long-term RFP solicits bids to provide up to 300 megawatts of purchased power to be available beginning in 1998 or 1999, for contract periods of between 5 and 20 years in duration. The Company has evaluated a total of 16 proposals received for both the short-term RFP and the long-term RFP and has begun negotiation with the bidders with the best proposals. Contracts are expected to be awarded in May 1996.

Capital Requirements

Projected capital expenditures, excluding costs related to portions of the Catawba Nuclear Station owned by the other Catawba joint owners, for the years set forth below, as now scheduled, are as follows (in millions):

	1996	1997	1998	1999	2000	Total
Duke Power — Electric						
Generation	$193	$210	$124	$115	$132	$ 774
Transmission	40	41	42	42	42	207
Distribution	199	198	199	200	201	997
Other	72	64	65	60	60	321
Nuclear Fuel	120	136	116	164	125	661
Total Duke Power — Electric	624	649	546	581	560	2,960
Associated Enterprises Group	226	194	178	206	219	1,023
Total Company	$850	$843	$724	$787	$779	$3,983

The Company's procedures for estimating capital expenditures for Duke Power — Electric (which include allowance for funds used during construction) utilize, among other things, past construction experience, current construction costs, allowances for inflation and the Company's business plan. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances for Duke Power — Electric are due to various factors, including revised load estimates, environmental matters and cost and availability of capital. Projections of the AEG capital expenditures are subject to periodic review and revision and may vary significantly as the business plans of AEG evolve to meet the opportunity presented by its markets.

The Company has substantially completed construction of a combustion turbine facility in Lincoln County, North Carolina to provide capacity at periods of peak demand. The Lincoln Combustion Turbine Station consists of 16 combustion turbines with a total generating capacity of 1,200 megawatts. The estimated total cost of the project is approximately $400 million. Twelve of the 16 units were placed into commercial operation in 1995, and as of March 1, 1996, the final four units were placed into commercial operation. During 1991, the NCUC granted the Certificate of Public Convenience and Necessity and the North Carolina Division of Environmental Management issued a final air permit for the facility. All appeals related to the issuance of the final air permit were resolved in 1995.

Joint Ownership of Generating Facilities

In order to reduce its need for external financing, the Company, through several transactions beginning in 1978, sold an 87½ percent undivided interest in the Catawba Nuclear Station to the other Catawba joint owners.

These transactions contemplate that the Company will operate the facility, interconnect its transmission system, wheel a certain portion of the capacity and energy of such facility to the respective participants, provide back-up services for such capacity, buy for its own use (whether or not the facility is generating electricity) that portion of the capacity not then contractually required by the respective participants, and provide supplemental power as required by the purchasers to enable them to provide service on a firm basis. The transactions also include a reliability exchange between the Catawba Nuclear Station and the McGuire Nuclear Station of the Company, which provides for an exchange of 50 percent of each other Catawba joint owner's retained capacity from its ownership interest in the Catawba units for like amounts of capability and output from units of the McGuire Nuclear Station. The implementation of the reliability exchange has not had, nor does the Company anticipate that such implementation will have, a material effect on earnings. (See Note 3, "Notes to Consolidated Financial Statements.")

The Company and North Carolina Municipal Power Agency Number 1 (NCMPA) and Piedmont Municipal Power Agency (PMPA), two of the four other joint owners of the Catawba Nuclear Station, entered into a settlement in September 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the NCUC on January 16, 1996 and the PSCSC on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity

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

Nuclear Station	Uranium Material	Conversion Service	Enrichment Service	Fabrication Service
Oconee	1997	1998	2000	2006
McGuire	1997	1998	2000	2009
Catawba	1997	1998	2000	2009

Uranium material requirements will be met through various supplier contracts, with uranium material produced primarily in the U.S. and Canada. The Company believes that it will be able to renew contracts as they expire or to enter into similar contractual arrangements with other nuclear fuel materials and services suppliers. Requirements not met by long-term supply contracts have been and will be fulfilled with uranium spot market purchases.

The Department of Energy (DOE) recently requested Expressions of Interest (EOI) to facilitate in the disposal of plutonium. The Company and Commonwealth Edison, along with the other joint owners of the Catawba Nuclear Station, responded to the EOI in early 1996. As this project is in its early developmental stage, management cannot predict the outcome of this process. However, the Company believes these matters should not have a material effect on the results of operations or financial position of the Company.

The Nuclear Waste Policy Act of 1982 requires that the DOE begin disposing of spent fuel no later than January 31, 1998. The Company has entered into the required contracts with the DOE for the disposal of nuclear fuel and began making payments in July 1983 for disposal costs of fuel currently being utilized. These payments, combined with a one-time payment for disposal costs of fuel consumed prior to April 7, 1983, have totaled about $510 million through 1995 related to the Company's ownership interest in nuclear plants. In December 1995, the DOE released a report which indicated that it expects a facility for spent fuel disposal will not be available until the year 2015. The DOE continues to pursue a centralized interim storage facility, with a target operation date of 1998, for earlier acceptance of spent fuel from utilities. The Company believes that it will be able to provide adequate on-system storage capacity until such time as the DOE begins receiving spent fuel.

Regulation

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

Environmental Matters. The Company is subject to federal, state, and local regulations with regard to air and water quality, hazardous and solid waste disposal, and other environmental matters. North Carolina has enacted a declaration of environmental policy requiring all state agencies to administer their responsibilities in accordance with such policy. The NCUC has adopted rules requiring consideration of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed generation facilities. South Carolina law also requires consideration by the PSCSC of environmental effects in determining whether certificates of public convenience and necessity will be granted for proposed major utility facilities, which include certain generation and transmission facilities. All of the Company's facilities which are currently under construction have been designed to comply with presently applicable environmental regulations. Such compliance has, however, increased the cost of electric service by requiring changes in the design and operation of existing facilities, as well as changes or delays in the design, construction and operation of new facilities. In 1995, the Company's construction costs for environmental protection totaled approximately $52 million, while the on-going environmental operation costs were approximately $25 million. The Company's 1996-2000 construction program includes costs for environmental protection which are estimated to be approximately $40 million, including $9.8 million in 1996, $4.1 million in 1997, $7.4 million in 1998, $9.7 million in 1999 and $9.4 million in 2000. These costs include expenditures associated with the Clean Air Act Amendments of 1990. However, governmental regulations establishing environmental protection

levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3, "Notes to Consolidated Financial Statements.") In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Fuel Supply

The Company presently relies principally on nuclear fuel and coal for the generation of electric energy. The Company's reliance on oil and gas is minimal and will remain minimal even with the addition of the Lincoln Combustion Turbine Station, which is designed to operate on either natural gas or oil.

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

	Generation by Source			Cost of Fuel per Net KWH Generated (Cents)		
	Year Ended December 31			Year Ended December 31		
	1995	1994	1993	1995	1994	1993
Coal	43.7%	46.9%	48.6%	1.56	1.54	1.6[illegible]
Nuclear (1)	53.7	51.0	49.1	0.57	0.56	0.5[illegible]
Oil and gas	—	—	—	—	—	—
All Fuels (cost based on weighted average) (1)	97.4	97.9	97.7	1.03	1.03	1.07
Hydroelectric (2)	2.6	2.1	2.3			
	100.0%	100.0%	100.0%			

(1) Statistics related to nuclear generation and all fuels reflect the Company's 12.5% ownership in the Catawba Nuclear Station.

(2) Generating figures are net of that output required to replenish pumped storage units during off-peak periods and do not include NP&L.

Coal. The Company obtains a large amount of its coal under long-term supply contracts with mining operators utilizing both underground and surface mining. The Company has on hand an adequate supply of coal. The Company's long-term supply contracts, all of which have price adjustment provisions, have expiration dates ranging from 1996 to 2003. The Company believes that it will be able to renew such contracts as they expire or to enter into similar contractual arrangements with other coal suppliers for quantities and qualities of coal required. The coal covered by the Company's long-term supply contracts is produced from mines located in eastern Kentucky, southern West Virginia and southwestern Virginia. The Company's requirements not met by long-term supply contracts have been and will be fulfilled with spot market purchases. The average sulfur content of coal being purchased by the Company is approximately 1 percent. Such coal satisfies the current emission limitation for sulfur dioxide for existing facilities. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — The Clean Air Act Amendments of 1990.")

standards are continually evolving and have not, in some cases, been fully established. These projections are subject to periodic review and revisions. Actual construction costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including cost and availability of capital.

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

WATER QUALITY. The Federal Water Pollution Control Act Amendments of 1987 (referred to herein as the "Clean Water Act") require permits for facilities that discharge into waters. The Company holds numerous such permits, which are issued periodically. The issuance of such permits is delegated by the EPA to state agencies in North and South Carolina. The Clean Water Act has been scheduled for review and reauthorization by Congress since 1994, but no legislation has been enacted. Until Congress acts upon the reauthorization, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

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

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as "Superfund", requires any individual or entity which may have owned or operated a contaminated site, as well as transporters or generators of hazardous wastes which were sent to such site, to assume joint and several responsibility for remediation of the site. Such parties are known as "potentially responsible parties" (PRPs). Some contamination sites are remediated pursuant to state acts which are similar to CERCLA. The Company has participated in site remediation activities in the past as a PRP at Superfund sites or similar state sites in the Charlotte area, near Chester, S.C., and in Pennsylvania and West Virginia. The Company's involvement in one Superfund site and one state site was resolved in early 1996. The Company is currently participating in PRP groups with regard to Superfund sites in Concord, North Carolina and Lenoir, North Carolina. While the total cost of remediation at these federal and state contamination sites may be substantial, the Company shares probable liability with other PRPs, many of which have substantial assets. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

Other contamination sites in which the Company is involved arise from the operation of manufactured gas plant (MGP) sites, which were commonplace in the Carolinas until the 1950s. Some such sites are still owned by the Company, and others are now owned by third parties. In North Carolina, the Company is participating in a state-sponsored program to investigate and, where appropriate, remediate MGP sites. In South Carolina, the Company is in the process of remediating an MGP site in Greenville. Management is of the opinion that resolution of these matters will not have a material adverse effect on the results of operations or financial position of the Company.

CERCLA has been scheduled for review and reauthorization by Congress since 1994, but has not been examined outside of the legislative committee structure. Until CERCLA reform occurs, management will be unable to assess what effect, if any, such reauthorization will have on the Company's operations.

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

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

Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company is planning for the replacement of steam generators at three units that have experienced SCC and has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. The current schedule for completion of the effort is as follows: Catawba Unit 1 — 1996, McGuire Unit 1 — 1997 and McGuire Unit 2 — 1997. The order of replacement is subject to change based on operational and project circumstances. The Catawba Unit 2 steam generators have not been scheduled for replacement. Steam generator replacement at each unit is expected to take approximately four months and cost approximately $170 million per unit, excluding the cost of replacement

power and the reimbursement of applicable costs by the other Catawba joint owners for Catawba Unit 1. The $170 million per unit cost estimate includes the cost of removal of steam generators being replaced. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the other joint owners, began a legal action in 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba Stations steam generators that were defective in design, workmanship and materials, requiring replacement well short of their stated design life. The lawsuit was settled in 1994. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the results of operations or financial position of the Company.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the NCUC and the PSCSC have granted the Company recovery of the estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume that units will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021; McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The NRC issued a rulemaking in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1995, the Company expensed approximately $56 million, which was contributed to the external funds and accrued an additional $1 million to the internal reserve. The balance of the external funds as of December 31, 1995, was $273 million. The balance of the internal reserve as of December 31, 1995, was $206 million and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid approximately $9.2 million during 1995 and $35.6 million cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of approximately $101 million in the Consolidated Balance Sheets at December 31, 1995.

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

Hydroelectric Licenses. The principal hydroelectric projects of the Company are licensed by FERC under Part I of the Federal Power Act. Eleven developments on the Catawba-Wateree River in North Carolina and South Carolina, with a nameplate rating of approximately 805 MW, are licensed for a term expiring in 2008. The Company also holds a license for the Keowee-Toxaway Project for a term expiring in 2016, covering the Keowee Hydro Station and the Jocassee Pumped Storage Station for a combined total of approximately 770 MW, on the upper tributaries of the Savannah River in northwestern South Carolina. Additionally, the Company is the licensee through 2027 for the Bad Creek Hydroelectric Station which uses Lake Jocassee as its lower reservoir and has a nameplate rating of 1,065 MW. NP&L holds licenses for 11 hydroelectric projects with a nameplate rating of 100 MW with license terms expiring 2001-2006. The Federal Power Act provides, among other things, that, upon the expiration of any license issued thereunder, the United States may (a) grant a new license to the licensee for the project, (b) take over the project upon payment to the licensee of its "net investment" in the project (but not in excess of the fair value thereof) plus severance damages, or (c) grant a license for the project to a new licensee subject to payment to the former licensee of the amount specified in (b) above.

Interconnections

The Company has major interconnections and arrangements with its neighboring utilities which it currently considers adequate for coordinated planning, emergency assistance, exchange of capacity and energy, and reliability of power supply.

Competition

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

The Energy Policy Act of 1992 (EPACT) is a major driver towards a more competitive market for wholesale sales of power. EPACT reformed provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, EPACT allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. In addition, EPACT permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that independent suppliers can sell at wholesale to customers wherever located. It does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

The FERC, responsible in large measure for implementation of the EPACT, has moved vigorously to implement its mandate, interpreting the statute broadly in issuing orders for third-party transmission service and issuing a number of rules of general applicability. The FERC, in late March of 1995, issued a Notice of Proposed Rulemaking (the "NOPR") in which it announced its intent to impose a final rule, applicable to all electric utilities subject to its jurisdiction, which will require all such utilities to adopt open-access transmission tariffs containing identical terms and conditions. The FERC should issue its final rule in 1996.

Open transmission access for wholesale customers as contemplated by the FERC's NOPR would provide energy suppliers, including the Company, with opportunities to sell and deliver capacity and energy at market-based prices. Engaging in such transactions could result in improved utilization of the Company's existing assets. In addition, such access would provide another supply option through which the Company can buy capacity and energy at attractive rates, influencing its competitive price position. However, sales to existing wholesale customers of the Company could be impacted by open access as contemplated by the NOPR either due to competitive pressure on the wholesale price of electricity, or the potential loss of sales as wholesale customers seek other options to meet their capacity and energy requirements at market-based prices. Wholesale sales, excluding transactions with other utilities, represented approximately 6.7 percent of the Company's total kilowatt-hour sales in 1995. Supplemental sales to the other joint owners of the Catawba Nuclear Station comprised the majority of such sales. Such supplemental sales will be declining in 1996 as a result of the retention of significantly larger portions of ownership entitlement by the other joint owners. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

In early 1995, prior to issuance of the FERC's NOPR, the Company and certain of its affiliates filed three applications with the FERC, all of which are designed to enable effective participation in the competitive environment of the changing electric utility industry. Duke Power filed an application for permission to sell at market-based rates up to 2,500 megawatts of capacity and energy from its own assets. Two of the Company's affiliates, Duke Energy Marketing Corporation (DEMC) and Duke/Louis Dreyfus L.L.C. (D/LD), filed applications with the FERC to become power marketers. All of the applications were supported by transmission tariffs which establish the rates, terms and conditions for transmission service to third parties on the Company's transmission system.

Late in 1995, the FERC granted the applications of Duke, DEMC, and D/LD; accepted Duke's transmission tariffs; and ordered a hearing on the rates to be charged for service under those tariffs. The terms and conditions of service are subject to the outcome of the FERC's final rule, and the rates are subject to the outcome of hearings before the FERC.

Wheeling of third party energy to a retail customer is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states regarding retail competition which could result in changes in the industry.

Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based price of electricity, profits could be reduced and utilities might be required to reduce their recorded asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require affected utilities to write off their associated regulatory assets. The regulatory assets of the Company are classified as "Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

Subsidiaries and Diversified Activities

The Company continues to aggressively pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Although these opportunities are primarily concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. The Company undertakes a continuous evaluation of the various lines of business it may enter or exit, with the objectives of enhancing shareholder value and managing any associated risk. (See "Subsidiaries and Diversified Activities Highlights" on page 50.)

Major subsidiaries and diversified activities include the following:

Crescent Resources, Inc. (Crescent) pursues both residential and commercial real estate development, in addition to providing forest management activities focused on growing trees suitable for use in the construction, furniture and paper industries. At December 31, 1995, Crescent owned approximately 2,398,000 square feet of office, retail and warehouse space and had approximately 400,000 square feet of commercial properties under construction. Additionally, Crescent had approximately 250,000 acres of land under its management at year end.

Duke Energy Group, Inc. (Duke Energy) develops, owns and manages electric power facilities in the United States and abroad. Duke Energy also markets electric power and natural gas through a joint venture with Louis Dreyfus Electric Power. Domestically, Duke Energy concentrates on advanced fossil-fueled generation including pulverized coal, circulating fluidized bed, coal gasification and natural gas technologies. Internationally, Duke Energy pursues advanced coal-fueled, hydroelectric and gas-fueled generation as well as transmission projects. Duke Energy has equity interests in two U.S. electric generation facilities and four international projects.

Nantahala Power and Light Company (NP&L) is a franchised electric utility which operates 11 hydroelectric plants with a total capacity of 100 megawatts. NP&L has approximately 53,000 customers in western North Carolina. NP&L sold 949,000 MWH in 1995 compared to 907,000 MWH in 1994, excluding sales to Duke Power.

Other Business Units include Church Street Capital Corp., which manages investment funds and provides equity funding and credit enhancements for its subsidiaries; Duke Engineering & Services, Inc., which markets engineering, construction, quality assurance, consulting and other engineering-related services for facilities other than coal-fired generating plants, both nationally and internationally; Duke/Fluor Daniel, a joint venture with Fluor Daniel, Inc., which provides engineering, construction and support of operating and maintenance activities, primarily for coal-fired generating plants, both nationally and internationally; Duke Merchandising, which sells and services quality electric appliances and electronics; DukeNet Communications, Inc., which develops and manages communications systems; and Duke Water Operations, which provides franchised water services for Anderson, South Carolina and Rutherfordton, North Carolina.

Employees

At December 31, 1995, the Company had 17,121 full-time employees, which included 1,355 full-time employees of subsidiaries and diversified activities. About 1,950 electrical operating employees are represented by the International Brotherhood of Electrical Workers (IBEW). During the last quarter of 1995, the Company reached new labor agreements with the IBEW for one year terms.

The number of full-time employees has decreased to the 1995 year-end level from 19,945 at year-end 1990. (See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — Resource Optimization.")

(c) 1995 includes KWH of the Lincoln Combustion Turbine Station prior to commercial operation.

(d) Does not include operating statistics of NP&L.

(e) Includes sales to NP&L.

(f) 1991 restated to eliminate certain duplicate customers.

Executive Officers of the Company

WILLIAM H. GRIGG, 63, Chairman of the Board and Chief Executive Officer. Mr. Grigg served as Chairman of the Board, President and Chief Executive Officer, effective April 28, 1994, until July 27, 1994 when he assumed his present position. He served as Vice Chairman of the Board beginning in 1991, and Executive Vice President, Customer Group, beginning in 1988.

STEVE C. GRIFFITH, JR., 62, Vice Chairman of the Board and General Counsel. Mr. Griffith served as Executive Vice President and General Counsel from 1991 until he assumed his present position in July 1994. He served as Senior Vice President and General Counsel from 1982 until 1991.

RICHARD B. PRIORY, 49, President and Chief Operating Officer. Mr. Priory served as Executive Vice President, Power Generation Group, from 1991 until he assumed his present position in July 1994. He was Senior Vice President, Generation and Information Services, from 1988 to 1991.

WILLIAM A. COLEY, 52, President, Associated Enterprises Group. Mr. Coley was named Senior Vice President, Power Delivery, in 1988; Senior Vice President, Customer Group, in 1990; and Executive Vice President, Customer Group, in 1991. He was named to his present position in July 1994.

RICHARD J. OSBORNE, 44, Senior Vice President and Chief Financial Officer. Prior to assuming his current position in July 1994, Mr. Osborne served as Vice President and Chief Financial Officer beginning in 1991 and Vice President, Finance, from 1988 to 1991.

JEFFREY L. BOYER, 39, Controller. Mr. Boyer served as Director of Corporate Accounting for more than five years prior to assuming his present position in July 1994.

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

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

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

Item 2. ***Properties.***

At December 31, 1995, the Company operated three nuclear generating stations, eight coal-fired stations and twenty-seven hydroelectric stations, all of which are located in North Carolina or South Carolina.

DUKE POWER COMPANY

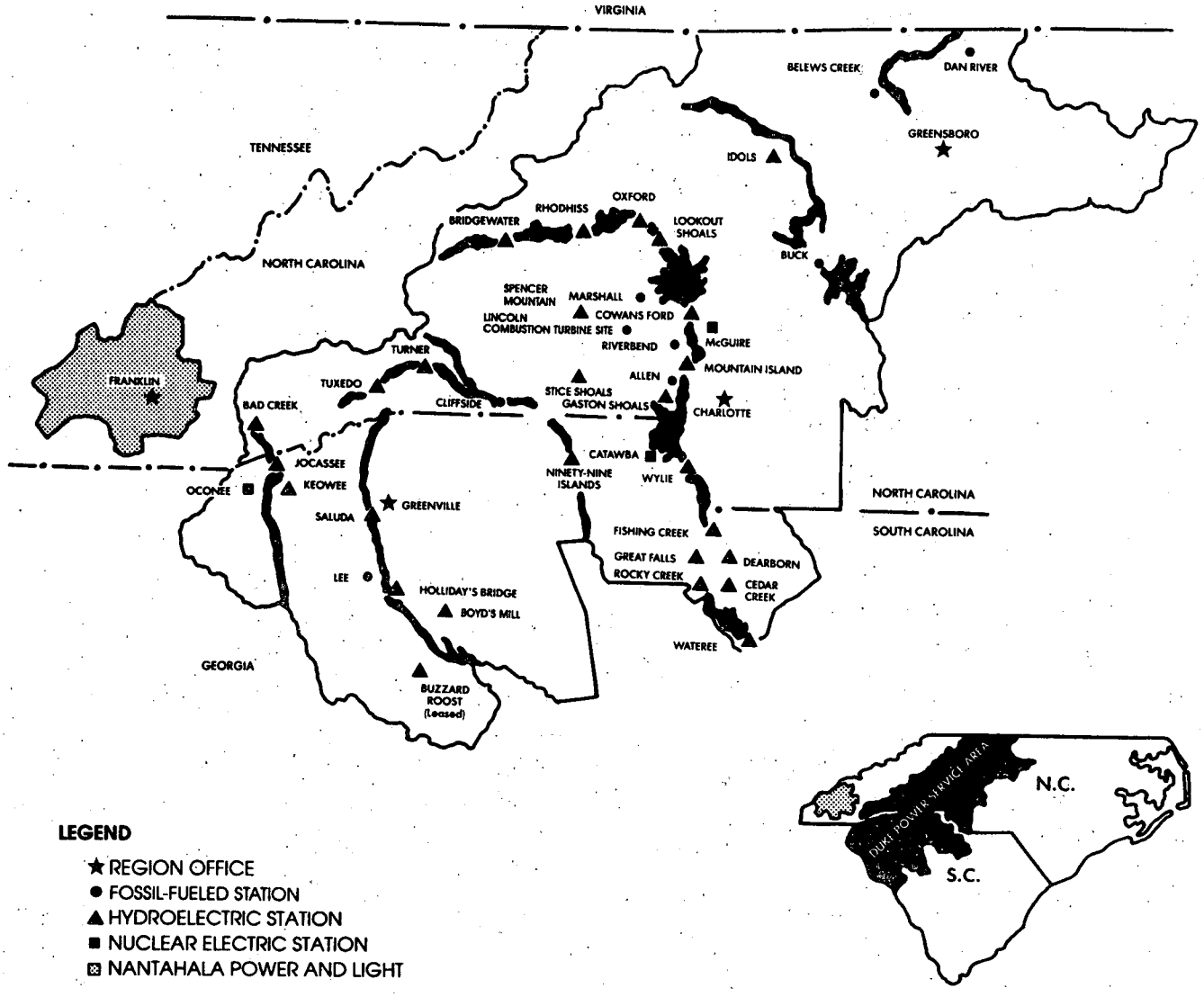
OPERATING STATISTICS

	Year ended December 31				
	1995	1994	1993	1992	1991
Sources of Electric Energy (d)					
Millions of kilowatt-hours:					
Generated — net output:					
Coal	32,389	32,714	34,097	28,999	26,455
Nuclear (a)	39,836	35,587	34,390	33,925	37,048
Hydro (b)	1,685	1,460	1,582	1,834	1,545
Oil and gas (c)	255	35	43	5	7
Total generation	74,165	69,796	70,112	64,763	65,055
Purchased power and net interchange	1,175	1,276	1,750	1,403	587
Total output	75,340	71,072	71,862	66,166	65,642
Plus: Purchases from Other Catawba Joint Owners	6,070	9,046	8,810	9,466	8,525
Total sources of energy	81,410	80,118	80,672	75,632	74,167
Line loss and company usage	4,673	4,555	4,614	4,590	4,280
Total kilowatt-hour sales	76,737	75,563	76,058	71,042	69,887
Average Cost Per Ton of Coal Burned	$ 41.72	$ 40.68	$ 42.21	$ 43.47	$ 45.21
Electric Energy Sales (d)					
Millions of kilowatt-hours:					
Residential	19,669	18,870	19,465	17,789	17,918
General service	18,160	17,289	16,904	15,818	15,586
Industrial					
Textile	12,151	12,285	11,954	11,685	11,315
Other	17,631	17,005	16,244	15,356	14,955
Other energy and wholesale (e)	8,330	10,274	11,337	10,360	10,132
Total kilowatt-hour sales billed	75,941	75,723	75,904	71,008	69,906
Unbilled kilowatt-hour sales	796	(160)	154	34	(19)
Total kilowatt-hour sales	76,737	75,563	76,058	71,042	69,887
Electric Revenue (d)					
Thousands of dollars:					
Residential	$1,441,362	$1,379,740	$1,424,173	$1,312,227	$1,272,322
General service	1,076,791	1,031,061	1,014,124	964,853	921,337
Industrial					
Textile	494,066	498,190	487,576	482,172	475,191
Other	766,750	745,154	726,399	696,413	668,765
Other energy and wholesale (e)	461,367	540,256	476,862	460,849	441,777
Other electric revenue	182,102	84,928	152,742	44,970	37,568
Total electric revenues	$4,422,438	$4,279,329	$4,281,876	$3,961,484	$3,816,960
Number of Customers — end of year (d)					
Residential	1,526,323	1,493,166	1,460,876	1,439,845	1,415,605
General service (f)	246,276	239,355	232,272	227,675	222,917
Industrial					
Textile	1,390	1,422	1,396	1,390	1,385
Other	7,320	7,320	7,338	7,314	7,255
Other energy and wholesale	8,470	8,187	7,957	7,773	7,605
Total customers	1,789,779	1,749,450	1,709,839	1,683,997	1,654,767
Residential Customer Statistics (d)					
Average number for the year	1,514,434	1,483,497	1,455,609	1,431,403	1,409,775
Average annual use — KWH	12,988	12,720	13,372	12,427	12,710
Average annual billing	$ 951.75	$ 930.06	$ 978.40	$ 916.74	$ 902.50
Average annual billed revenue per KWH (d)					
Cents:					
Residential	7.33	7.31	7.32	7.38	7.10
General service	5.93	5.96	6.00	6.10	5.91
Industrial	4.23	4.24	4.31	4.36	4.35
Other energy and wholesale (e)	5.54	5.26	4.21	4.45	4.36

(a) Includes 12.5% of Catawba generation.

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

Duke Power Service Area



LEGEND

- ★ REGION OFFICE
- ● FOSSIL-FUELED STATION
- ▲ HYDROELECTRIC STATION
- ■ NUCLEAR ELECTRIC STATION
- ⊠ NANTAHALA POWER AND LIGHT

Subsequent Event

The Company's Board of Directors has authorized the implementation of a program to repurchase up to $1 billion of the Company's Common Stock from time to time over the next five years. The repurchases will be made either on the open market (in accordance with applicable regulations) or through privately negotiated transactions. The Board's authorization provides flexibility for the Company's management to undertake the repurchase program at its discretion, and does not establish a target stock price or timetable for repurchases. The timing and amount of repurchases will be determined by cash available to the Company for such purpose and by the availability of alternative investment opportunities.

The following is a list of the major generating stations owned by the Company at December 31, 1995:

Facility	Energy Source	Net MW
Oconee	Nuclear	2,538
McGuire	Nuclear	2,258
Catawba (a)	Nuclear	282
Belews Creek	Coal	2,240
Marshall	Coal	2,090
Allen	Coal	1,140
Cliffside	Coal	760
Others	Coal	1,469
Bad Creek	Hydroelectric	1,065
Jocassee	Hydroelectric	610
Others	Hydroelectric	1,007
Combustion turbines (b)	Oil and gas	1,484

(a) Represents Duke's 12.5% ownership share in Catawba Nuclear Station.

(b) Includes 900 MW of the Lincoln Combustion Turbine Station which were in commercial operation as of December 31, 1995.

The Company has substantially completed the construction of the Lincoln Combustion Turbine Station, a 16-turbine facility designed to provide capacity at periods of peak demand. The station has a total generating capacity of 1,200 megawatts. Twelve of the 16 units were placed into commercial operation in 1995, and as of March 1, 1996, the final four units were placed into commercial operation. The facility is designed to operate on either natural gas or oil.

In addition to the electric generating plants described above, the Company owned, as of December 31, 1995, approximately 8,300 conductor miles of transmission lines and approximately 73,500 conductor miles of distribution lines. As of such date, the Company's transmission and distribution systems comprised approximately 1,600 substations with an installed transformer capacity of approximately 84,200,000 kVA.

NP&L's generation facilities consist of eleven hydroelectric plants with an aggregate nameplate capacity of approximately 100 MW. The transmission backbone of the system is a 161 kV line from Santeetlah to substations at Robbinsville, Nantahala Plant, Oak Grove, Webster and Thorpe Plant.

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

Substantially all electric plant is mortgaged under the Indenture relating to the First and Refunding Mortgage Bonds of the Company.

For additional information concerning the properties of the Company, see "Business — Energy Requirements and Capability."

Item 3. ***Legal Proceedings.***

Reference is made to "Business — Regulation", "Management's Discussion and Analysis of Results of Operations and Financial Condition, Current Issues — Commitments and Contingencies" and "Note 13, Notes to Consolidated Financial Statements, Commitments and Contingencies — Other."

Item 4. ***Submission Of Matters To A Vote Of Security Holders.***

No matters were submitted to a vote of the Company's security holders during the last quarter of 1995.

PART II.

Item 5. ***Market for the Registrant's Common Equity and Related Stockholder Matters.***

The Common Stock of the Company is traded on the New York Stock Exchange. At December 31, 1995, there were approximately 129,265 holders of shares of such Common Stock.

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

Common Stock	Dividends Per Share	Stock Price Range	
		High	Low
1995 By Quarter			
Fourth	$0.51	$47 7/8	$43 1/8
Third	0.51	43 3/4	40
Second	0.49	42 3/4	38 1/4
First	0.49	40 3/4	37 3/8
1994 By Quarter			
Fourth	$0.49	$42 1/8	$38
Third	0.49	39 7/8	35 1/2
Second	0.47	37	32 7/8
First	0.47	43	35 3/4

Item 6.

SELECTED FINANCIAL DATA

	1995	1994	1993	1992	1991
Condensed consolidated statements of income (thousands)					
Operating revenues	$ 4,676,684	$ 4,488,913	$ 4,466,233	$ 4,122,503	$ 3,962,605
Operating expenses	3,327,633	3,309,087	3,258,422	3,087,422	2,968,239
Operating income	1,349,051	1,179,826	1,207,811	1,035,081	994,366
Interest expense and other income	(168,072)	(143,931)	(171,419)	(223,028)	(117,725)
Income before income taxes	1,180,979	1,035,895	1,036,392	812,053	876,641
Income taxes	466,441	397,019	409,977	303,970	293,018
Net income	714,538	638,876	626,415	508,083	583,623
Dividends on preferred and preference stock	48,903	49,724	52,429	56,407	54,683
Earnings for common stock	$ 665,635	$ 589,152	$ 573,986	$ 451,676	$ 528,940
Common stock data					
Shares of common stock					
year-end (thousands)	204,859	204,859	204,859	204,859	204,699
average (thousands)	204,859	204,859	204,859	204,819	203,431
Per share of common stock					
Earnings	$ 3.25	$ 2.88	$ 2.80	$ 2.21	$ 2.60
Dividends	$ 2.00	$ 1.92	$ 1.84	$ 1.76	$ 1.68
Book value — year-end	$ 23.36	$ 22.13	$ 21.17	$ 20.26	$ 19.86
Market price — high-low	$ 47 7/8-37 3/8	$ 43-32 7/8	$ 44 7/8-35 3/8	$ 37 1/2-31 3/8	$ 35-26 3/4
— year-end	$ 47 3/8	$ 38 1/8	$ 42 3/8	$ 36 1/8	$ 35
Balance sheet data (thousands)					
Total assets	$13,358,484	$12,862,228	$12,293,605	$11,012,795	$10,617,552
Long-term debt	$ 3,711,405	$ 3,567,122	$ 3,285,397	$ 3,288,111	$ 3,235,492
Preferred stock with sinking fund requirements	$ 234,000	$ 279,500	$ 281,000	$ 279,519	$ 228,650

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

Results of Operations

Earnings and Dividends. Earnings per share increased 13 percent from $2.88 in 1994 to $3.25 in 1995. The increase was primarily due to increased kilowatt-hour sales to weather sensitive classes.

Earnings per share increased from $2.80 in 1993 to $3.25 in 1995, indicating an average annual growth rate of 8 percent. Total Company earned return on average common equity was 14.3 percent in 1995 compared to 13.3 percent in 1994 and 13.6 percent in 1993.

The Company continued its practice of annually increasing the common stock dividend. Common dividends per share increased at an average annual rate of 4 percent from $1.84 in 1993 to $2.00 in 1995. Indicated annual dividends per share increased to $2.04.

Revenues and Sales. Operating revenues increased at an average annual rate of 2 percent from 1993 to 1995, primarily because of increased retail kilowatt-hour sales to weather sensitive classes and growth in the general service and industrial customer classes. As discussed below, increased retail sales were partially offset by decreased sales to wholesale customers. Revenues from subsidiaries and diversified operations contributed $73 million to the increase in revenues over the three-year period, primarily from increased developed lot and land sales and engineering services and construction fees.

Wholesale revenues declined in 1995 and are expected to decline again in 1996 as a result of the retention of significantly larger portions of ownership entitlement by the other joint owners of the Catawba Nuclear Station. This increased retention reduces the joint owners' supplemental requirements supplied by the Company. The effect on earnings of such wholesale revenue declines is partially offset by declines in purchased power costs from the other joint owners which are not subject to levelization. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

Kilowatt-hour sales from Duke Power electric operations increased 2 percent in 1995 compared to 1994. Sales to residential, general service and other industrial customers increased by 4 percent, 5 percent and 4 percent, respectively, as a result of warmer summer weather, cooler winter weather and continued economic growth in Duke Power's service are However, sales to textile customers decreased 1 percent. Wholesale sales decreased 19 percent primarily due to a decrease 36 percent in supplemental sales requirements to the other joint owners of the Catawba Nuclear Station. A new record peak demand of 15,542 megawatts was set in August 1995 during warmer than normal temperatures.

Operating Expenses. From 1994 to 1995, other operation and maintenance expenses increased 5 percent. Increased activities of the subsidiaries and diversified operations associated with both engineering services and other project development efforts contributed to this increase. Increases in distribution and transmission expenses were offset by reductions in nuclear and fossil outage costs. In 1995 and 1994, the Company had relatively constant costs associated with work force reduction programs and certain claims that are expected to be non-recurring in nature.

Other operation and maintenance expenses increased at an average annual rate of 6 percent from 1993 to 1995. Costs associated with the enhanced vested retirement benefit program in 1995 as well as other non-recurring costs contributed to this increase in addition to increased activities of the subsidiaries and diversified operations associated with engineering services and other project development efforts. (For additional information on the vested retirement program, see Current Issues, "Resource Optimization," page 23.)

Fuel expense increased at an average annual rate of 1 percent from 1993 to 1995. The increase was due primarily to higher system production requirements, offset by improved nuclear generation.

Net interchange and purchased power expenses decreased from $535 million in 1993 to $468 million in 1995, an average annual decrease of 6 percent. This decrease was primarily the result of lower purchased power costs from the other joint owners not subject to levelization as the other joint owners retained significantly larger portions of their ownership entitlement. In 1996, net interchange and purchased power is expected to decrease again as purchased power costs from the other joint owners continue to decline.

From 1993 to 1995, depreciation and amortization expense decreased at an average annual rate of 4 percent, primarily because the reduction in the amortization of property losses more than offset increased depreciation associated with additional investments. These investments were primarily associated with distribution plant, including investment to suppo customer growth, commercial operation of 12 units of the Lincoln Combustion Turbine Station, and fossil plant resulti

from bringing refurbished units back on-line. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs, "Meeting Future Power Needs," page 23.)

Interest Expense and Other Income. Interest expense increased at an average annual rate of 3 percent from 1993 to 1995, primarily due to long-term debt financing activities in 1994.

Allowance for funds used during construction (AFUDC) and other deferred returns, net of associated taxes, represented 13 percent of earnings for common stock in 1995 compared to 10 percent in 1993. AFUDC and other deferred returns are expected to be less than 11 percent of total earnings during the next three years.

The deferred return, net of associated taxes, on the purchased capacity levelization deferral related to the joint ownership of the Catawba Nuclear Station represented 7 percent of earnings for common stock in 1995, compared to 7 percent in 1994 and 6 percent in 1993. The growth in this return is due to the increasing cumulative impact of the Company's funding of purchased power costs through 1995, which the Company expects to collect through current rates in future periods. The deferred purchased capacity balance is expected to begin to decline in 1996. (For additional information on purchased capacity levelization, see Capital Needs, "Purchased Capacity Levelization," page 22.)

AFUDC, net of associated taxes, represented 5 percent of earnings for common stock in 1995 compared to 6 percent in 1994 and 4 percent in 1993. The changes were primarily the result of the construction and subsequent commercial operation of the Lincoln Combustion Turbine Station as 12 units were brought on-line at various times during 1995. (For additional information on the Lincoln Combustion Turbine Station, see Capital Needs, "Meeting Future Power Needs," page 23.)

Liquidity and Resources

Duke Power Company Rate Matters. The Company's most recent general rate increase requests in the North Carolina and South Carolina retail jurisdictions were filed and approved in 1991. Additionally, Duke Power has a bulk power sales agreement with Carolina Power & Light Company (CP&L) to provide CP&L 400 megawatts of capacity as well as associated energy when needed for a six-year period which began July 1, 1993. Electric rates in all of Duke Power's regulatory jurisdictions were reduced by adjustment riders to reflect capacity revenues received from this CP&L bulk power sales agreement.

Catawba Settlements. The Company and North Carolina Municipal Power Agency Number 1 (NCMPA) and Piedmont Municipal Power Agency (PMPA), two of the four other joint owners of the Catawba Nuclear Station, entered into a settlement in September 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the North Carolina Utilities Commission (NCUC) on January 16, 1996 and the Public Service Commission of South Carolina (PSCSC) on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or the financial position of the Company.

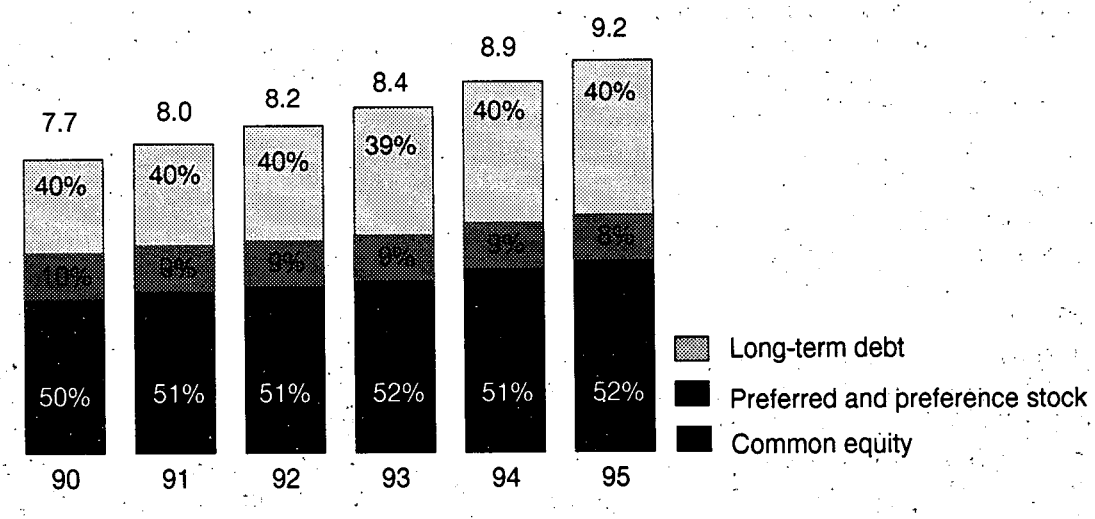
The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners, which previously have been approved by the Company's retail regulatory commissions. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.) In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years will conform to the settlement agreements, which were approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

Cash from Operations. Consolidated net cash provided by operating activities in 1995 accounted for 81 percent of total cash from operating, financing and investing activities compared with 67 percent in 1994 and 46 percent in 1993. When

1993 and 1995 refinancing activities are excluded, substantially all of the Company's capital needs were met by cash generated from operating activities. Refinancing activities were insignificant in 1994.

Financing and Investing Activities. The Company's consolidated capital structure at year-end 1995, including subsidiary long-term debt, was 52 percent common equity, 40 percent long-term debt and 8 percent preferred stock. This structure is consistent with the Company's target to maintain a double-A credit rating. As of December 31, 1995, Duke Power's bonds were rated "AA" by Fitch Investors Service, "Aa2" by Moody's Investors Service, and "AA-" by Standard & Poor's Group and Duff & Phelps.

Capital Structure
Billions of dollars



The Company had total credit facilities of $669.9 million and $440.0 million as of December 31, 1995 and 1994, respectively. The Company had unused credit facilities of $440.6 million and $259.9 million as of December 31, 1995 and 1994, respectively.

In response to favorable market conditions in 1993, the Company issued $1.5 billion in long-term debt and $220 million in preferred stock, most of which was used to retire higher cost debt and preferred stock. In 1995, the Company issued $178 million of long-term debt, of which $72 million was used to retire higher cost long-term debt. The Company also retired $96 million of preferred stock and $80 million of long-term debt in 1995.

In order to obtain variable rate financing at an attractive cost, the Company entered into interest rate swap agreements associated with the November 29, 1994 issuance of $200 million aggregate principal amount of its First and Refunding Mortgage Bonds 8% Series B due 1999 and the August 21, 1995 issuance of $100 million aggregate principal amount of its First and Refunding Mortgage Bonds 7½% Series B due 2025. The interest rate swaps are reset quarterly based upon the three-month London Interbank Offered Rate (LIBOR). As a result of the interest rate swap contracts, interest expense is recognized at the weighted average rate for the year tied to the LIBOR rate. The weighted average rates at December 31, 1995 and 1994 were 6.14% and 5.95%, respectively, for the 8% Series B due 1999 and 7.06% in 1995 for the 7½% Series B due 2025.

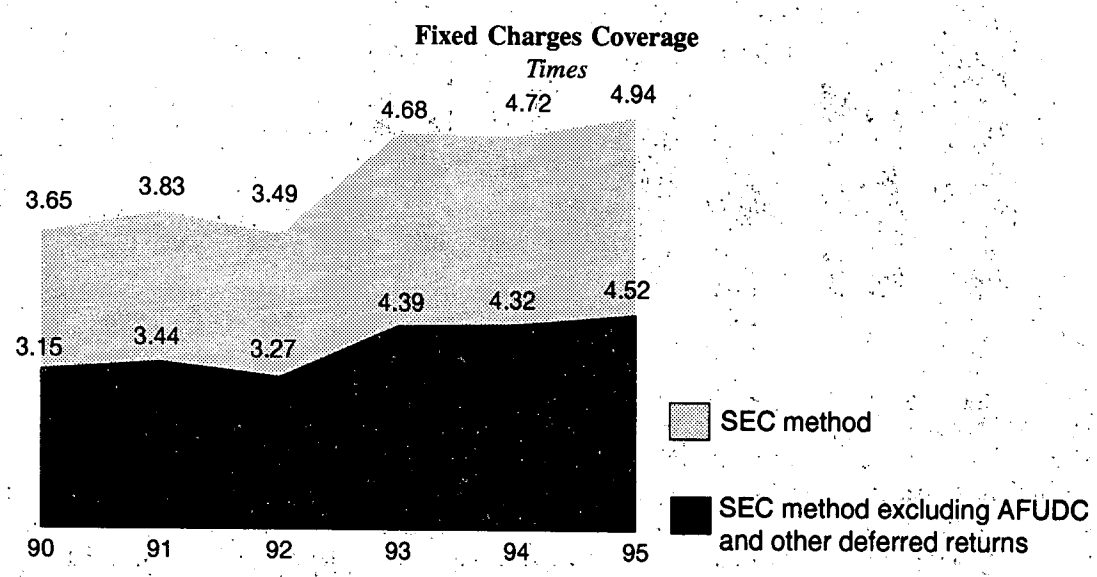
The Company has also entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Japanese yen associated with various steam generator purchase contracts. The hedge transaction with a notional amount of approximately $25 million at December 31, 1994, was fully liquidated by November 1995. The Company recorded any gains or losses associated with the hedge as an adjustment to the capitalized cost of the steam generators.

Duke Energy Group, Inc. has entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Chilean peso associated with expected equity contributions over the next two years to a joint venture. The hedge transaction had a notional amount of approximately $17 million at December 31, 1995. Duke Energy Group, Inc. records gains or losses associated with the hedge as an adjustment to investments in joint ventures.

Duke Power's embedded cost of long-term debt, excluding debt of subsidiaries, was 7.94 percent for 1995 compared to 7.98 percent in 1994 and 8.01 percent in 1993. The embedded cost of preferred stock was 7.06 percent in 1995 compared to

6.99 percent in 1994 and 6.76 percent in 1993. The decreases in the embedded cost of long-term debt are primarily the result of the Company's refinancing activities and the resulting lower-cost debt. The increase in the embedded cost of preferred stock from 1993 to 1995 reflects the impact of increased adjustable dividend rates on a certain series of preferred stock and the retirement of preferred stock in 1995.

Fixed Charges Coverage. Consolidated fixed charges coverage using the SEC method increased to 4.94 times for 1995 compared to 4.72 and 4.68 times in 1994 and 1993, respectively. Coverage increased primarily because of higher earnings. Consolidated fixed charges coverage, excluding AFUDC and other deferred returns, was 4.52 times for 1995 compared with 4.32 in 1994 and 4.39 in 1993 and the Company goal of 3.5 times. Coverage was higher in 1995 than 1994 and 1993 as a result of increased earnings excluding AFUDC and other deferred returns.



Capital Needs

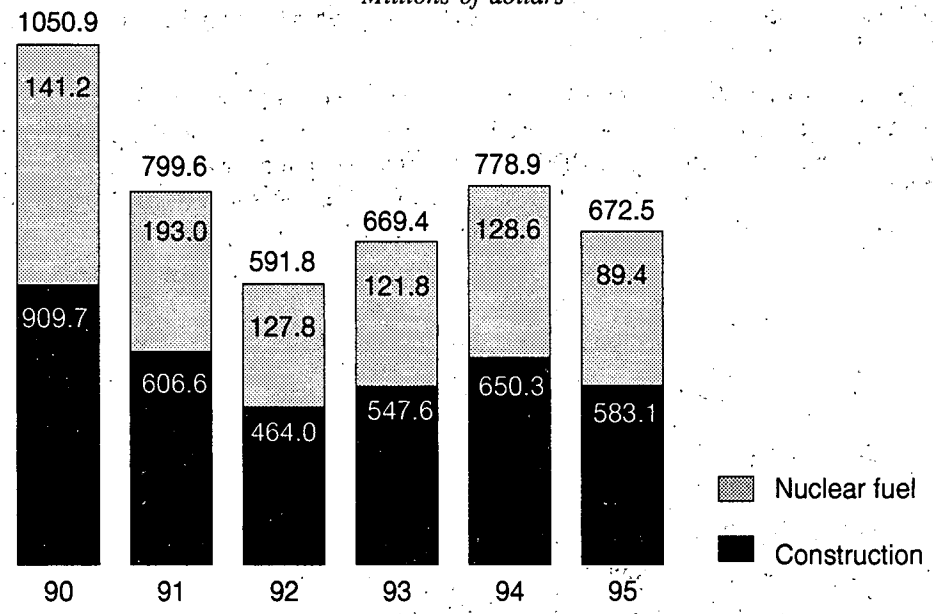
Property Additions and Retirements. Additions to property and nuclear fuel of $794 million and retirements of $288 million resulted in an increase in gross plant of $506 million in 1995.

Since January 1, 1993, additions to property and nuclear fuel of $2.4 billion and retirements of $864 million have resulted in an increase in gross plant of $1.5 billion.

Construction Expenditures. Plant construction costs for generating facilities supporting Duke Power electric operations, including AFUDC, increased from $182 million in 1993 to $281 million in 1995, primarily because of construction of the Lincoln Combustion Turbine Station and the steam generator replacement project. (For more information, see Capital Needs, "Meeting Future Power Needs," page 23 and Current Issues, "Stress Corrosion Cracking," page 24.) Construction costs for distribution plant, including AFUDC, decreased from $240 million in 1993 to $221 million in 1995.

Duke Power Construction Costs*

Millions of dollars



* Includes AFUDC and excludes NP&L and Duke Power's other subsidiaries.

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including AFUDC, are $2.3 billion and $661 million, respectively, for 1996 through 2000. These construction expenditures are primarily for distribution and production related activities representing $997 million and $774 million, respectively. These projections are subject to periodic reviews and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

Projected capital expenditures of subsidiaries and diversified activities are $1.0 billion for 1996 through 2000 of which a significant portion is for real estate development. These projections are subject to periodic review and revision and may vary significantly as the business plans of the Associated Enterprises Group evolve to meet the opportunity presented by its markets.

For 1996 through 2000, the Company anticipates substantially funding its projected construction and capital expenditures through the internal generation of funds.

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

Such rate treatments require the Company to fund portions of the purchased capacity payments until these costs, including returns, are recovered at a later date. The Company recovers the accumulated costs and returns when the sum of the declining purchased capacity payments and accrual of returns for the current period drop below the levelized revenues. In the North Carolina retail jurisdiction, and wholesale jurisdiction regulated by the Federal Energy Regulatory Commission (FERC), purchased capacity payments and the accrual of deferred returns continue to exceed levelized revenues. However, in 1996, the levelized revenues are expected to exceed the purchased capacity payments and accrual of deferred returns. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments and accrual of deferred returns. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including final true-ups.

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

The Company is constructing a combustion turbine facility in Lincoln County, North Carolina. The Lincoln Combustion Turbine Station, designed to provide capacity at periods of peak demand, will consist of 16 combustion turbines with a total generating capacity of 1,200 megawatts. The estimated total cost of the project is approximately $400 million. Units 1 through 12 began commercial operation during 1995 and the remaining four units are scheduled to begin commercial operation in 1996.

In 1995, the Company issued two requests for proposals (RFP) to solicit competitive bids for its future electric generating capacity resources. The short-term RFP could provide options for up to 675 megawatts of capacity with terms of 1 to 4 years. The long-term RFP solicits bids to provide up to 300 megawatts of purchased power to be available beginning in 1998 or 1999, for contract periods of between 5 and 20 years in duration. The Company has evaluated a total of 16 proposals received for both the short-term RFP and the long-term RFP and has begun negotiation with the bidders with the best proposals. Contracts are expected to be awarded in May 1996.

The purchase of capacity and energy is also an integral part of meeting future power needs. As of January 1, 1996, the Company has 300 megawatts of firm purchased capacity from other generators of electricity under contract, including 62 megawatts from qualifying facilities.

Demand-side management programs benefit the Company and its customers by promoting energy efficiency, providing for load control through interruptible control features, shifting usage to off-peak periods and increasing strategic sales of electricity. In return for participation in demand-side management programs, customers may be eligible to receive various incentives which help reduce their net investment in high-efficiency equipment or their electric bills. The November 1991 rate orders of the NCUC and the PSCSC provided for recovery in rates of a designated level of costs for demand-side management programs and allowed the deferral for later recovery of certain demand-side management costs that exceed the level reflected in rates, including a return on the deferred costs. The Company ultimately expects recovery through rates of associated deferred costs, not to exceed $75 million including deferred returns in the North Carolina retail jurisdiction. The annual costs deferred, including the return, were approximately $16 million and $11 million in North Carolina and South Carolina, respectively, in 1995 and $15 million and $10 million in North Carolina and South Carolina, respectively, in 1994. As of December 31, 1995, the balance of deferred demand-side management costs as presented on the Consolidated Balance Sheets in "Other deferred debits" is $58 million and $38 million in North Carolina and South Carolina, respectively.

Current Issues

While the Company improved its financial performance in 1995 compared to 1994, its ability to maintain and improve its current level of earnings will depend on several factors. As the industry becomes increasingly competitive, the Company's ability to control costs will be an important factor in maintaining a pricing structure that is both attractive to customers and profitable to the Company. Wheeling of third party energy to a retail customer is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states regarding retail competition which could result in changes in the industry. (For additional information on competition, see Current Issues, "Competition.") Management cannot predict the outcome of these matters and their impact, if any, on the Company's future financial position and results of operation. The Company is focusing on providing competitive prices to its industrial customers, as well as to wholesale customers who have access to alternative sources of energy. Other significant factors impacting the Company's future earnings levels include continued economic growth in the Piedmont Carolinas, the success of the Company's subsidiaries and diversified activities, and the outcomes of various legislative and regulatory actions.

Resource Optimization. The Company has been engaged in a concentrated effort to more efficiently and effectively use its resources through better work practices. In 1995, the Company offered to certain employees an Enhanced Vested Benefits program (EVB) which gave targeted employees, who left the Company, an enhanced vested retirement package and the Company's standard severance pay based on years of service. This program will result in the departure of approximately 900 employees by the end of the first quarter of 1996. During 1994, the Company offered an Enhanced Voluntary Separation program (EVS) which gave most employees the option of leaving the Company for a lump-sum payment and the Company's standard severance pay based on years of service. This program resulted in the departure of approximately 1,300 employees in 1994. Implementing various efficiency practices has resulted in streamlined workflows and provided the opportunity for

work force reduction programs such as EVB and EVS. The number of full-time employees has decreased from 19,945 at year-end 1990 to 17,121 at year-end 1995.

Nuclear Decommissioning Costs. Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Such estimates presume each unit will be decommissioned as soon as possible following the end of its license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021, McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The Nuclear Regulatory Commission issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1995, the Company expensed approximately $56 million, which was contributed to the external funds, and accrued an additional $1 million to the internal reserve. The balance of the external funds as of December 31, 1995, was $273 million. The balance of the internal reserve as of December 31, 1995, was $206 million and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets.

Both the NCUC and the PSCSC have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

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

The Clean Air Act Amendments of 1990. The Clean Air Act Amendments of 1990 require a two-phase reduction by electric utilities in the aggregate annual emissions of sulfur dioxide and nitrogen oxide by the year 2000. The Company currently meets all requirements of Phase I. The Company supports the national objective of clean air in the most cost-effective manner and has already reduced emissions through the use of low-sulfur coal in its fossil plants, efficient plant operations and by using nuclear generation. The sulfur dioxide provisions of the Act allow utilities to choose among various alternatives for compliance. To meet the Phase II requirements by 2000, the Company's current strategy includes the use of lower sulfur coal, emission allowance purchases, low nitrogen oxide burners and emission monitoring equipment. A one-time cost associated with bringing the Company into compliance with the Act could range from $94 million to $320 million. Additional operating expenses of approximately $55 million will be incurred for fuel premiums and emission allowance purchases each year after 2000. This strategy is contingent upon developments in the emissions allowance market, lower sulfur coal fuel premiums, future regulatory and legislative actions, and advances in clean air technology.

Stress Corrosion Cracking. Stress corrosion cracking (SCC) has occurred in the steam generators of Units 1 and 2 at the McGuire Nuclear Station and Unit 1 at the Catawba Nuclear Station. Catawba Unit 2, which has certain design differences and came into service at a later date, has not yet shown the degree of SCC which has occurred in McGuire Units 1 and 2 and Catawba Unit 1. It is, however, too early in the life of Catawba Unit 2 to determine the extent to which SCC may be a problem. Although the Company has taken steps to mitigate the effects of SCC, the inherent potential for future SCC in the McGuire and Catawba steam generators still exists. The Company is planning for the replacement of steam generators at three units that have experienced SCC and has signed an agreement with Babcock & Wilcox International to purchase replacement steam generators. The current schedule for completion of the effort is as follows: Catawba Unit 1 — 1996, McGuire Unit 1 — 1997 and McGuire Unit 2 — 1997. The order of replacement is subject to change based on operational and project circumstances. The Catawba Unit 2 steam generators have not been scheduled for replacement. Steam generator

replacement at each unit is expected to take approximately four months and cost approximately $170 million, excluding the cost of replacement power and the reimbursement of applicable costs by the other joint owners of Catawba Unit 1. Stress corrosion problems are excluded under the Company's nuclear insurance policies.

The Company, in connection with its McGuire and Catawba stations and on behalf of the other joint owners of the Catawba Station, began a legal action in 1990, alleging that Westinghouse Electric Corporation knowingly supplied to the McGuire and Catawba stations steam generators that were defective in design, workmanship, and materials, requiring replacement well short of their stated design life. The lawsuit was settled in 1994. While the court order does not allow disclosure of the terms of the settlement, the Company believes the litigation was settled on terms that provided satisfactory consideration to the Company and will not have a material effect on the Company's results of operations or financial position.

Competition. The Energy Policy Act of 1992 (EPACT) is a major driver towards a more competitive market for wholesale sales of power. EPACT reformed provisions of the Public Utility Holding Company Act of 1935 (PUHCA) and Part II of the Federal Power Act to remove certain barriers to competition for the supply of electricity. For example, EPACT allows utilities to develop independent electric generating plants in the United States for sales to wholesale customers, as well as to contract for utility projects internationally, without becoming subject to regulation under PUHCA as an electric utility holding company. In addition, EPACT permits the FERC to order transmission access for third parties to transmission facilities owned by another entity so that independent suppliers can sell at wholesale to customers wherever located. It does not, however, permit the FERC to issue an order requiring transmission access to retail customers.

The FERC, responsible in large measure for implementation of the EPACT, has moved vigorously to implement its mandate, interpreting the statute broadly in issuing orders for third-party transmission service and issuing a number of rules of general applicability. The FERC in late March of 1995 issued a Notice of Proposed Rulemaking (the "NOPR") in which it announced its intent to impose a final rule, applicable to all electric utilities subject to its jurisdiction, which will require all such utilities to adopt open-access transmission tariffs containing identical terms and conditions. The FERC should issue its final rule in 1996.

Open transmission access for wholesale customers as contemplated by the FERC's NOPR would provide energy suppliers, including the Company, with opportunities to sell and deliver capacity and energy at market-based prices. Engaging in such transactions could result in improved utilization of the Company's existing assets. In addition, such access would provide another supply option through which the Company can buy capacity and energy at attractive rates, influencing its competitive price position. However, sales to existing wholesale customers of the Company could be impacted by open access as contemplated by the NOPR either due to competitive pressure on the wholesale price of electricity, or the potential loss of sales as wholesale customers seek other options to meet their capacity and energy requirements at market-based prices. Wholesale sales, excluding transactions with other utilities, represented approximately 6.7 percent of the Company's total kilowatt-hour sales in 1995. Supplemental sales to the other joint owners of the Catawba Nuclear Station comprised the majority of such sales. Such supplemental sales will be declining in 1996 as a result of the retention of significantly larger portions of ownership entitlement by the other joint owners. (For additional information on Catawba joint ownership, see Note 3 to the Consolidated Financial Statements.)

In early 1995, prior to issuance of the FERC's NOPR, the Company and certain of its affiliates filed three applications with the FERC, all of which are designed to enable effective participation in the competitive environment of the changing electric utility industry. Duke Power filed an application for permission to sell at market-based rates up to 2,500 megawatts of capacity and energy from its own assets. Two of the Company's affiliates, Duke Energy Marketing Corporation (DEMC) and Duke/Louis Dreyfus L.L.C. (D/LD), filed applications with the FERC to become power marketers. All of the applications were supported by transmission tariffs which establish the rates, terms and conditions for transmission service to third parties on the Company's transmission system.

Late in 1995, the FERC granted the applications of Duke, DEMC, and D/LD; accepted Duke's transmission tariffs; and ordered a hearing on the rates to be charged for service under those tariffs. The terms and conditions of service are subject to the outcome of the FERC's final rule, and the rates are subject to the outcome of hearings before the FERC.

Wheeling of third party energy to a retail customer is not generally allowed in the Company's service territory. However, there are discussions and events at the national level and within certain states regarding retail competition which could result in changes in the industry.

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

reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced and utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require affected utilities to write off their associated regulatory assets. The regulatory assets of the Company are classified as "Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

Commitments and Contingencies. The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which may involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or the financial position of the Company.

Subsidiaries and Diversified Operations. The Company continues to aggressively pursue both domestic and international diversified business opportunities that are synergistic with the Company's core business to provide additional value to the Company's shareholders. Among the Company's current industry pursuits are: ownership of electric power facilities, power marketing, real estate, communications, engineering consulting and various energy services. Although these opportunities are primarily concentrated in areas that utilize the Company's expertise, they present different and potentially greater risks than does the Company's core business. The Company only pursues opportunities in which the expected returns are commensurate with the risks and makes efforts to mitigate such risks. The Company undertakes a continuous evaluation of the various lines of business it may enter or exit, with the objectives of enhancing shareholder value and managing any associated risk.

Domestically, non-electric property of the Company's subsidiaries and diversified activities was $335 million and $286 million at December 31, 1995 and 1994, respectively. The Company had equity investments in joint ventures, which own assets within the United States, of $58 million and $14 million at December 31, 1995 and 1994, respectively.

Internationally, the Company had equity investments in joint ventures, which own generation and transmission facilities of $105 million and $94 million at December 31, 1995 and 1994, respectively. Additionally, the Company, through its nonregulated subsidiaries, had loaned $23 million to certain of these joint ventures at December 31, 1995.

The Company's subsidiaries and diversified activities contributed $54 million to net income in 1995 compared with $52 million in 1994 and $22 million in 1993. From 1993 to 1995, increased developed lot and land sales, and engineering services and construction fees generated additional income. These increases were offset by personal communications services joint venture losses in 1995. Additionally, a one-time gain on the sale of an investment in preferred stock of an independent power development company in 1994 contributed to the increase in diversified income from 1993 to 1994.

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

DUKE POWER COMPANY

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DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME

	Year ended December 31,		
	1995	1994	1993
	Dollars in Thousands		
Operating revenues (Notes 1, 2 and 11)	$4,676,684	$4,488,913	$4,466,233
Operating expenses			
Fuel used in electric generation (Note 1)	744,226	705,019	732,246
Net interchange and purchased power (Notes 2 and 3)	468,293	553,355	535,125
Other operation and maintenance	1,403,547	1,341,659	1,254,028
Depreciation and amortization (Note 1)	458,131	459,781	496,971
General taxes	253,436	249,273	240,052
Total operating expenses	3,327,633	3,309,087	3,258,422
Operating income	1,349,051	1,179,826	1,207,811
Interest expense and other income (Note 1)			
Interest expense	(289,318)	(270,217)	(274,051)
Allowance for funds used during construction and other deferred returns	125,040	111,872	82,600
Other, net	(3,794)	14,414	20,032
Total interest expense and other income	(168,072)	(143,931)	(171,419)
Income before income taxes	1,180,979	1,035,895	1,036,392
Income taxes (Notes 1 and 4)	466,441	397,019	409,977
Net income	714,538	638,876	626,415
Dividends on preferred and preference stock	48,903	49,724	52,429
Earnings for common stock	$ 665,635	$ 589,152	$ 573,986
Common stock data (Note 6)			
Average shares outstanding (thousands)	204,859	204,859	204,859
Earnings per share	$ 3.25	$ 2.88	$ 2.80
Dividends per share	$ 2.00	$ 1.92	$ 1.84

See Notes to Consolidated Financial Statements.

DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year ended December 31,		
	1995	1994	1993
	Dollars in Thousands		
Balance — Beginning of year	$2,605,920	$2,410,825	$2,223,718
Add — Net income	714,538	638,876	626,415
Total	3,320,458	3,049,701	2,850,133
Deduct			
Dividends			
Common stock	409,716	393,370	376,937
Preferred and preference stock	48,903	49,724	52,429
Capital stock transactions, net	3,564	687	9,942
Total deductions	462,183	443,781	439,308
Balance — End of year	$2,858,275	$2,605,920	$2,410,825

See Notes to Consolidated Financial Statements.

DUKE POWER COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	1995	1994	1993
	Dollars in Thousands		
Cash flows from operating activities			
Net Income	$ 714,538	$ 638,876	$ 626,415
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash items			
Depreciation and amortization	674,816	647,515	664,355
Deferred income taxes and investment tax credit amortization	5,989	94,261	62,897
Allowance for equity funds used during construction	(23,082)	(27,411)	(17,221)
Purchased capacity levelization	(33,149)	(268,925)	(20,049)
Other, net	76,029	22,460	73,607
(Increase) Decrease in			
Accounts receivable	(136,838)	47,586	(37,131)
Inventory	(14,549)	(28,568)	24,904
Prepayments	(7,178)	(435)	(2,396)
Increase (Decrease) in			
Accounts payable	11,694	(52,506)	(28,184)
Taxes accrued	14,454	(51,641)	25,797
Interest accrued and other liabilities	28,934	14,523	30,508
Total adjustments	597,120	396,859	777,087
Net cash provided by operating activities	1,311,658	1,035,735	1,403,502
Cash flows from investing activities			
Construction expenditures and other property additions	(713,299)	(772,452)	(599,759)
Investment in nuclear fuel	(76,603)	(108,711)	(111,731)
External funding for decommissioning	(56,470)	(52,524)	(52,524)
Pre-funded pension cost	—	(30,000)	(50,000)
Investment in joint ventures	(54,945)	(6,718)	(70,345)
Net change in investment securities	54,425	17,922	46,489
Net cash used in investing activities	(846,892)	(952,483)	(837,870)
Cash flows from financing activities			
Proceeds from the issuance of			
First and refunding mortgage bonds	173,839	343,824	1,395,682
Preferred stock	—	—	215,633
Pollution control bonds	—	—	76,265
Short-term notes payable, net	48,200	86,300	(105,200)
Construction loans and other	47,643	57,032	13,280
Payments for the redemption of			
First and refunding mortgage bonds	(157,365)	(81,781)	(1,399,336)
Preferred stock	(100,516)	(1,500)	(224,295)
Pollution control bonds	—	—	(79,310)
Construction loans and other	(9,416)	(18,885)	(12,454)
Dividends paid	(458,018)	(443,633)	(427,868)
Other	(1,153)	(20,991)	(6,752)
Net cash used in financing activities	(456,786)	(79,634)	(554,355)
Net increase in cash	7,980	3,618	11,277
Cash at beginning of year	37,430	33,812	22,535
Cash at end of year	$ 45,410	$ 37,430	$ 33,812

See Notes to Consolidated Financial Statements.

DUKE POWER COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 1995	December 31, 1994
	Dollars in Thousands	
ASSETS		
Current assets		
Cash (Notes 5 and 10)	$ 45,410	$ 37,430
Short-term investments (Notes 1 and 10)	76,300	132,692
Receivables (less allowance for losses: 1995 — $6,352; 1994 — $6,637) (Note 1)	689,703	552,865
Inventory — at average cost	341,841	319,385
Prepayments and other	22,900	15,722
Total current assets	1,176,154	1,058,094
Investments and other assets		
Investments in joint ventures (Note 11)	163,274	108,330
Other investments, at cost or less (Note 10)	85,194	83,226
Nuclear decommissioning trust funds (Notes 10 and 14)	273,466	172,390
Pre-funded pension cost (Note 12)	80,000	80,000
Total investments and other assets	601,934	443,946
Property, plant and equipment (Notes 1, 3, 9, 13 and 14)		
Electric plant in service (at original cost)		
Production	7,154,332	6,747,397
Transmission	1,532,302	1,439,435
Distribution	4,105,513	3,965,393
Other	1,030,226	1,020,192
Electric plant in service	13,822,373	13,172,417
Less accumulated depreciation and amortization	5,122,192	4,810,004
Electric plant in service, net	8,700,181	8,362,413
Nuclear fuel	731,691	757,983
Less accumulated amortization	453,921	415,560
Nuclear fuel, net	277,770	342,423
Construction work in progress (including nuclear fuel in process: 1995 — $25,500; 1994 — $52,273)	382,582	558,730
Total electric plant, net	9,360,533	9,263,566
Other property — at cost (less accumulated depreciation: 1995 — $29,956; 1994 — $24,137)	354,713	302,383
Total property, plant and equipment, net	9,715,246	9,565,949
Deferred debits (Notes 1, 3, 4 and 13)		
Purchased capacity costs	965,473	932,324
Debt expense	180,930	186,306
Regulatory asset related to income taxes	490,676	489,292
Regulatory asset related to DOE assessment fee	101,274	102,467
Other	126,797	83,850
Total deferred debits	1,865,150	1,794,239
Total assets	$13,358,484	$12,862,228
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 343,692	$ 343,688
Notes payable (Notes 5 and 10)	155,300	107,100
Taxes accrued (Note 1)	34,884	29,999
Interest accrued	73,675	72,157
Current maturities of long-term debt and preferred stock (Notes 8 and 9)	12,071	93,759
Other (Note 13)	149,555	121,539
Total current liabilities	769,177	768,242
Long-term debt (Notes 5, 9 and 10)	3,711,405	3,567,122
Accumulated deferred income taxes (Notes 1 and 4)	2,382,204	2,348,631
Deferred credits and other liabilities		
Investment tax credit (Notes 1 and 4)	261,347	272,594
DOE assessment fee (Note 1)	101,274	102,467
Nuclear decommissioning costs externally funded (Note 14)	273,466	172,390
Other	390,427	318,453
Total deferred credits and other liabilities	1,026,514	865,904
Preferred and preference stock with sinking fund requirements (Notes 8 and 10)	234,000	279,500
Preferred and preference stock without sinking fund requirements (Notes 7 and 10)	450,000	500,000
Commitments and contingencies (Note 13)		
Common stockholders' equity (Note 6)		
Common stock, no par, 300,000,000 shares authorized; 204,859,339 shares outstanding for 1995 and 1994	1,926,909	1,926,909
Retained earnings	2,858,275	2,605,920
Total common stockholders' equity	4,785,184	4,532,829
Total liabilities and stockholders' equity	$13,358,484	$12,862,228

See Notes to Consolidated Financial Statements.

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Nature of Operations

The Company is primarily engaged in the generation, transmission, distribution and sale of electric energy in the central portion of North Carolina and the western portion of South Carolina, comprising the area in both states known as the Piedmont Carolinas. The Company is one of the nation's largest investor-owned electric utilities.

The Company is also engaged in a variety of diversified operations, most of which are organized in separate subsidiaries. The Company's subsidiaries and diversified activities are in the Associated Enterprises Group (AEG). AEG includes Church Street Capital Corp.; Crescent Resources, Inc.; Duke Energy Group, Inc.; Duke Engineering & Services, Inc.; Duke/Fluor Daniel; Duke Merchandising; DukeNet Communications, Inc.; Duke Water Operations; and Nantahala Power and Light Company. Certain of these subsidiaries have invested in both domestic and international joint ventures. (See Note 11.)

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

B. Revenues

Electric revenues are recorded as service is rendered to customers. "Receivables" on the Consolidated Balance Sheets include $206,792,000 and $163,270,000 as of December 31, 1995 and 1994, respectively, for electric service that has been rendered but not yet billed to customers.

C. Additions to Electric Plant

The Company capitalizes all construction-related direct labor and materials as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of money (allowance for funds used during 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.

D. Allowance for Funds Used During Construction (AFUDC)

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

The AFUDC rates of 9.3, 9.6 and 9.3 percent for Duke Power for 1995, 1994 and 1993, respectively, include a component for debt cost on a pre-tax basis. Rates for all periods are compounded semiannually.

E. Other Deferred Returns

Other deferred returns represent the estimated financing costs associated with funding certain regulatory assets. These regulatory assets primarily arise from the Company's funding of purchased capacity costs above levels collected in rates. Other deferred returns are non-cash items. They are primarily recognized as an addition to "Purchased capacity costs" and as an offsetting credit to "Interest expense and other income."

F. Depreciation and Amortization of Electric Plant

Provisions for electric plant depreciation are recorded using the straight-line method. The year-end composite weighted-average depreciation rates were 3.48, 3.46 and 3.47 percent for 1995, 1994 and 1993, respectively.

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

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

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

A provision in the Energy Policy Act of 1992 established a fund for the decontamination and decommissioning of the DOE's uranium enrichment plants. Licensees are subject to an annual assessment for 15 years based on their pro rata share of past enrichment services. The annual assessment is recorded as fuel expense. The Company paid $9,205,000 during 1995 and has paid $35,551,000 cumulatively related to its ownership interest in nuclear plants. The Company has reflected the remaining liability and regulatory asset of $101,274,000 in the Consolidated Balance Sheets at December 31, 1995.

G. Subsidiaries

The Company's consolidated financial statements reflect consolidation of all of its majority-owned subsidiaries. Intercompany transactions have been eliminated in consolidation.

H. Income Taxes

The Company and its subsidiaries file a consolidated federal income tax return.

Deferred income taxes have been provided for temporary differences. Temporary differences occur when events and transactions recognized for financial reporting result in taxable or tax-deductible amounts in future periods. Investment tax credits have been deferred and are being amortized over the estimated useful lives of the related properties.

I. Unamortized Debt Premium, Discount and Expense

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

J. Consolidated Statements of Cash Flows

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

Total income taxes paid were $441,440,000, $372,416,000 and $354,981,000 for the years ended December 31, 1995, 1994 and 1993, respectively.

Interest paid, net of amounts capitalized, was $258,698,000, $236,696,000 and $249,659,000 for the years ended December 31, 1995, 1994 and 1993, respectively.

K. Cost-Based Regulation

As a regulated entity, the Company is subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Accordingly, the Company records certain assets and liabilities that result from the effects of the ratemaking process that would not be recorded under generally accepted accounting principles for non-regulated entities. Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced, and utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require the affected utilities to write off their associated regulatory assets. The regulatory assets of the Company are classified

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

as "Deferred debits" on the Consolidated Balance Sheets. Substantially all of the "Deferred debits" are regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Company's future financial position and results of operations. However, the Company continues to position itself to effectively meet these challenges by maintaining prices that are locally, regionally and nationally competitive.

NOTE 2. RATE MATTERS

Duke Power Company

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

The most recent general rate increase requests in the Company's retail jurisdictions were filed and approved in 1991. The Company also filed its most recent general rate increase request within the FERC wholesale jurisdiction in 1991. A negotiated settlement between the Company and the wholesale customers was approved by the FERC in 1992.

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

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

A bill ratified by the North Carolina legislature in 1987 to assure the legality of such adjustments in rates had its expiration provision repealed in March 1995.

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

Nantahala Power and Light Company

During 1992, Nantahala Power and Light Company (NP&L) filed an application for a general rate increase with the NCUC. A general rate increase was approved in June 1993 which resulted in additional annual revenues of $4.3 million. Purchased power costs of NP&L are reviewed annually and during general rate case proceedings by the NCUC. NP&L is allowed to adjust rates for past over- or under-recovery of purchased power costs. Therefore, NP&L defers the difference between actual purchased power costs incurred and those recovered through rates.

NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES

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

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

Each owner has provided its own financing for its ownership interest in the station.

NOTE 3: JOINT OWNERSHIP OF GENERATING FACILITIES — Continued

The Company retains a 12.5 percent ownership interest in the Catawba Nuclear Station. As of December 31, 1995, $499,209,000 of "Electric plant in service" and "Nuclear fuel" represents the Company's investment in Units 1 and 2. Accumulated depreciation and amortization of $185,264,000 associated with Catawba has been recorded as of year-end. The Company's share of operating costs of Catawba is included in the Consolidated Statements of Income.

In connection with the joint ownership, the Company has entered into contractual agreements with the other joint owners to purchase declining percentages of the generating capacity and energy from the plant. These purchased power agreements were effective beginning with the commercial operation of each unit. Unit 1 and Unit 2 began commercial operation in June 1985 and August 1986, respectively. The purchased power agreements were established for 15 years for NCMPA and PMPA and 10 years for NCEMC and Saluda River. While the purchased power agreements with NCMPA and PMPA extend for 15 years, a significant decrease in the percentage of capacity and energy the Company is obligated to purchase occurs in the 11th calendar year of operation for each unit. This significant decrease occurred in 1995 for Unit 1 and will occur in 1996 for Unit 2. Certain provisions in the agreements with NCEMC and Saluda River have moderated the rate of decrease in the percentage of capacity and energy that the Company is obligated to purchase until 1996 when the Company has no further obligation to purchase capacity and related energy.

The agreements also provide for supplemental power sales by the Company to the other joint owners. Such power sales are to satisfy capacity and energy needs of the other joint owners beyond the capacity and energy which they retain from Catawba or potentially acquire in the form of other resources. As the joint owners retain more capacity and energy from Catawba, or a third party, supplemental power sales are expected to decline.

The agreements with each of the other joint owners include provisions that the Company will provide generating reserves to backstand the other joint owners' retained capacity in the Catawba plant at the system average cost of installed capacity. Additionally, the agreements include certain reliability exchanges designed to manage outage-related risks by exchanging energy entitlements between the Catawba Nuclear Station and the McGuire Nuclear Station, impacting the Company as well as all the other joint owners.

Purchased energy cost payments are based on variable operating costs and are a function of the generation output of Catawba. Purchased capacity payments are based on the fixed costs of the plant and include the capital costs and fixed operating and maintenance costs. Actual purchased capacity costs for 1995 and projected obligations for 1996 through 2000, including the impact of the 1995 settlement agreement with NCMPA and PMPA (See Note 13), are as follows (dollars in thousands):

Year	Purchased Capacity Capital Cost	Purchased Capacity Fixed O&M	Total Purchased Capacity
1995 Actual	$237,978	$83,358	$321,336
1996 Projected	$ 83,870	$41,510	$125,380
1997 Projected	$ 65,803	$35,042	$100,845
1998 Projected	$ 47,609	$26,541	$ 74,150
1999 Projected	$ 34,752	$19,646	$ 54,398
2000 Projected	$ 4,217	$ 2,542	$ 6,759

Effective in its November 1991 rate order, the North Carolina Utilities Commission reaffirmed the Company's recovery, on a levelized basis, of the capital costs and fixed operating and maintenance costs of capacity purchased from the other joint owners. The Public Service Commission of South Carolina in its November 1991 rate order reaffirmed the Company's recovery on a levelized basis of the capital costs of capacity purchased from the other joint owners. Levelization was reaffirmed through inclusion in rates approved in March 1992 by the Federal Energy Regulatory Commission (FERC). The portion of purchased capacity subject to levelization not currently recovered in rates is being deferred, and the Company is recording a return on the accumulated balance. The Company recovers the accumulated balance, including the return, when the sum of the declining purchased capacity payments and accrual of returns for the current period drops below the levelized revenues. Jurisdictional levelizations are intended to recover total costs, including returns, and are subject to adjustments, including

NOTE 3. JOINT OWNERSHIP OF GENERATING FACILITIES — Continued

final true-ups. The Company recovers the costs of purchased energy and the non-levelized portion of purchased capacity on a current basis.

The current levelized revenues approved in the Company's last general rate proceedings are $211,423,000, $94,137,000 and $6,815,000 for North Carolina retail, South Carolina retail and Other Wholesale (FERC), respectively. Purchased power costs, subject to levelization, are deferred based on allocation factors of approximately 62 percent, 26 percent and 2 percent for North Carolina retail, South Carolina retail and Other Wholesale (FERC), respectively. The Company also recovers an allocated amount of purchased power costs in the pricing of supplemental sales made to the other joint owners on a current basis.

In 1995, in the North Carolina retail and FERC wholesale jurisdictions, purchased capacity payments and the accrual of deferred returns continued to exceed levelized revenues. However, in 1996, the levelized revenues are expected to exceed the purchased capacity payments and accrual of deferred returns. In the South Carolina retail jurisdiction, cumulative levelized revenues have exceeded purchased capacity payments and accrual of deferred returns.

For the years ended December 31, 1995, 1994 and 1993, the Company recorded purchased capacity and energy costs from the other joint owners of $388,246,000, $604,505,000 and $547,899,000, respectively. These amounts, after adjustments for the costs of capacity purchased not reflected in current rates, are included in "Net interchange and purchased power" in the Consolidated Statements of Income. As of December 31, 1995 and 1994, $965,473,000 and $932,324,000, respectively, associated with the cost of capacity purchased but not reflected in current rates have been accumulated in the Consolidated Balance Sheets as "Purchased capacity costs."

NOTE 4. INCOME TAX EXPENSE

Accumulated deferred income taxes consist primarily of the following (dollars in thousands):

	December 31, 1995		December 31, 1994	
Excess tax over book depreciation at historical tax rates	$1,387,925		$1,343,605	
Regulatory liability related to adjusting deferred taxes to the current statutory tax rate	(114,538)*		(120,422)*	
Net excess tax over book depreciation		$1,273,387		$1,223,183
Regulatory asset related to restating to a pre-tax basis		605,214*		609,714*
Deferred Catawba purchased capacity costs		374,112		361,018
Book versus tax basis difference		60,443		89,058
Loss on bond redemptions		68,135		70,067
Other		913		(4,409)
Total deferred income taxes		$2,382,204		$2,348,631

* The net regulatory asset related to income taxes is $490,676,000 for 1995 and $489,292,000 for 1994.

Total deferred income tax liability was $2,946,711,000 as of December 31, 1995, and $2,873,373,000 as of December 31, 1994. Total deferred income tax asset was $564,507,000 as of December 31, 1995, and $524,742,000 as of December 31, 1994.

NOTE 4. INCOME TAX EXPENSE — Continued

Income tax expense for the years ended December 31, 1995, 1994 and 1993 consisted of the following (dollars in thousands):

	1995	1994	1993
Current income taxes			
Federal	$377,237	$249,968	$283,930
State	83,215	52,790	63,150
Total current income taxes	460,452	302,758	347,080
Deferred taxes, net			
Federal	13,466	83,359	59,267
State	3,770	22,153	14,887
Total deferred taxes, net	17,236	105,512	74,154
Investment tax credit amortization	(11,247)	(11,251)	(11,257)
Total income tax expense	$466,441	$397,019	$409,977

Income taxes differ from amounts computed by applying the statutory tax rate to pre-tax income for the years ended December 31, 1995, 1994 and 1993 as follows (dollars in thousands):

	1995	1994	1993
Income taxes on pre-tax income at the statutory federal rate of 35%	$413,343	$362,563	$362,737
Increase (reduction) in tax resulting from:			
Allowance for funds used during construction (AFUDC)	(8,079)	(9,594)	(6,027)
Amortization of investment tax credit deferrals	(11,247)	(11,251)	(11,257)
AFUDC in book depreciation/amortization	21,057	19,027	25,694
Deferred income tax flowback at rates higher than statutory	(5,675)	(5,530)	(9,091)
State income taxes, net of federal income tax benefits	56,210	47,872	51,289
Other items, net	832	(6,068)	(3,368)
Total income tax expense	$466,441	$397,019	$409,977

NOTE 5. SHORT-TERM BORROWINGS AND CREDIT FACILITIES

The following credit facilities were available to the Company at December 31, 1995 and 1994, with 25 and 26 commercial banks, respectively:

Type of Facility	Line of Credit at December 31, 1995	Outstanding at December 31, 1995	Line of Credit at December 31, 1994	Outstanding at December 31, 1994
Annually renewable lines of credit	$ 64,900,000	$29,300,000	$ 44,980,000	$10,100,000
Two-year revolving facilities (a)	40,000,000	—	40,000,000	—
Three-year revolving facilities (b)	355,000,000	—	355,000,000	—
Four-year revolving facilities (c)	210,000,000	30,043,000	—	—
	$669,900,000	$59,343,000	$439,980,000	$10,100,000

(a) The Company had $40,000,000 in pollution control bonds, included in long-term debt, outstanding throughout 1995 and 1994 backed by the unused portion of these facilities.

(b) The Company had $130,000,000 in commercial paper, included in long-term debt, outstanding throughout 1995 and 1994 backed by the unused portion of these facilities.

(c) The outstanding balance of $30,043,000 is included in long-term debt.

NOTE 5. SHORT-TERM BORROWINGS AND CREDIT FACILITIES — Continued

Cash balances maintained at the banks on deposit were $17,120,000 as of December 31, 1995, and $13,214,000 as of December 31, 1994. Cash balances and fees compensate banks for their services, even though the Company has no formal compensating-balance arrangements. To compensate certain banks for credit facilities, the Company maintained balances of $45,000 and $49,000 as of December 31, 1995 and 1994, 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):

	Twelve Months Ended		
	December 31, 1995	December 31, 1994	December 31, 1993
Amount outstanding at end of period — average rate of 5.91% as of December 31, 1995, 6.02% as of December 31, 1994, and 3.55% as of December 31, 1993	$155,300	$107,100	$ 20,800
Maximum amount outstanding during the period	$264,300	$143,400	$180,800
Average amount outstanding during the period	$ 88,470	$ 24,161	$ 35,366
Weighted-average interest rate for the period — computed on a daily basis	6.05%	4.58%	3.19%

NOTE 6. COMMON STOCK AND RETAINED EARNINGS

Common Stock

As of December 31, 1995, a total of 7,004,659 shares was reserved for issuance for stock plans.

Retained Earnings

As of December 31, 1995, substantially all of the Company's retained earnings were unrestricted as to the declaration or payment of dividends.

NOTE 7. PREFERRED AND PREFERENCE STOCK WITHOUT SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1995 and 1994:

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

NOTE 7. PREFERRED AND PREFERENCE STOCK WITHOUT SINKING FUND REQUIREMENTS — Continued

As of December 31, 1995 and 1994, there were no shares of preference stock outstanding. Preferred stock without sinking fund requirements as of December 31, 1995 and 1994, was as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1995	1994
4.50% C	1964	350,000	$ 35,000	$ 35,000
5.72% D	1966	350,000	35,000	35,000
6.72% E	1968	350,000	35,000	35,000
7.85% S	1992	600,000	60,000	60,000
7.00% W	1993	500,000	50,000	50,000
7.04% Y	1993	600,000	60,000	60,000
7.72% (Preferred Stock A)	1992	1,600,000	40,000	40,000
6.375% (Preferred Stock A)	1993	2,400,000	60,000	60,000
Adjustable Rate A	1986	500,000	—	50,000
Auction Series A	1990	750,000	75,000	75,000
Total			$450,000	$500,000

NOTE 8. PREFERRED AND PREFERENCE STOCK WITH SINKING FUND REQUIREMENTS

The following shares of stock were authorized with or without sinking fund requirements as of December 31, 1995 and 1994:

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

As of December 31, 1995 and 1994, there were no shares of preference stock outstanding. Preferred stock with sinking fund requirements as of December 31, 1995 and 1994, was as follows (dollars in thousands):

Rate/Series	Year Issued	Shares Outstanding	1995	1994
5.95% B (Preferred Stock A)	1992	800,000	$ 20,000	$ 20,000
6.10% C (Preferred Stock A)	1992	800,000	20,000	20,000
6.20% D (Preferred Stock A)	1992	800,000	20,000	20,000
7.12% Q	1987	470,000	—	47,000
7.50% R	1992	850,000	85,000	85,000
6.20% T	1992	130,000	13,000	13,000
6.30% U	1992	130,000	13,000	13,000
6.40% V	1992	130,000	13,000	13,000
6.75% X	1993	500,000	50,000	50,000
Less: Current sinking fund requirements				
7.12% Q			—	(1,500)
Total			$234,000	$279,500

The annual sinking fund requirements through 2000 are $0 in 1996 and 1997, $4,250,000 in 1998, $24,250,000 in 1999 and $37,250,000 in 2000. Some additional redemptions are permitted at the Company's option.

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

NOTE 9. LONG-TERM DEBT

Long-term debt outstanding as of December 31, 1995 and 1994, was as follows (dollars in thousands):

Series	Year Due	1995	1994
First and Refunding Mortgage Bonds:			
6.47%-6.60%	1995	$ —	$ 40,300
4½%	1995	—	40,000
6.59%	1996	3,000	3,000
5⅜%	1997	72,600	72,600
5⅝%	1997	100,000	100,000
5.17%	1998	50,000	50,000
7.5%	1999	100,000	100,000
6¼%	1999	65,000	65,000
5.76%	1999	5,000	5,000
5.78%	1999	25,000	25,000
5.79%	1999	30,000	30,000
8% B	1999	200,000	200,000
7%	2000	100,000	100,000
7% B	2000	100,000	100,000
5⅞%	2001	150,000	150,000
6⅝% B	2003	100,000	100,000
5⅞% C	2003	75,000	75,000
6.125%	2003	75,000	75,000
8%	2004	75,000	75,000
6¼% B	2004	100,000	100,000
7.37%-7.41%	2004	100,000	100,000
7%	2005	200,000	200,000
6⅜%	2008	125,000	125,000
9⅝%	2020	—	46,982
10⅛% B	2020	—	24,854
8¾%	2021	150,000	150,000
8⅜% B	2021	150,000	150,000
8⅝%	2022	100,000	100,000
7⅜%	2023	200,000	200,000
6⅞% B	2023	200,000	200,000
7⅞%	2024	150,000	150,000
6¾%	2025	150,000	150,000
7½% B	2025	100,000	—
8.27%	2025	21,000	—
8.27%	2025	50,000	—
8.28%	2025	2,000	—
8.30%	2025	5,000	—
8.95%	2027	15,681	15,769
7%	2033	150,000	150,000
Pollution Control bonds:			
7.70%	2012	$ 20,000	$ 20,000
7.75% B	2017	10,000	10,000
7.50%	2017	25,000	25,000
3.76%	2014	40,000	40,000
5.80%	2014	77,000	77,000
Subtotal		3,466,281	3,440,505
Other long-term debt:			
Capitalized leases		7,477	26,039
Other long-term debt		147,410	130,000
Unamortized debt discount and premium, net		(61,674)	(62,918)
Current maturities of long-term debt		(4,295)	(81,926)
Subtotal (a)		3,555,199	3,451,700
Subsidiary long-term debt:			
Crescent Resources, Inc. (b)		130,694	92,102
Nantahala Power and Light		33,288	33,653
Current maturities of long-term debt		(7,776)	(10,333)
Subtotal		156,206	115,422
Total long-term debt		$3,711,405	$3,567,122

(a) Substantially all of Duke Power's electric plant was mortgaged as of December 31, 1995.

(b) Substantial amounts of Crescent Resources, Inc.'s real estate development projects, land and buildings are pledged as collateral.

NOTE 9. LONG-TERM DEBT — Continued

As of December 31, 1995 and 1994, the Company had $40,000,000 in pollution control revenue bonds backed by an unused, two-year revolving credit facility of $40,000,000. In addition, the Company had $130,000,000 in commercial paper outstanding throughout 1995 and 1994 backed by unused three-year revolving credit facilities. These facilities are on a fee basis. Both the $40,000,000 in pollution control bonds and the $130,000,000 in commercial paper are included in long-term debt.

As of December 31, 1995, Crescent Resources, Inc. had $65,526,000 in mortgage loans which mature through 2000 and $35,125,000 in mortgage loans maturing in 2001 or thereafter. Additionally, Crescent Resources, Inc. had $30,043,000 outstanding at December 31, 1995, included in long-term debt on a $50,000,000 four-year revolving credit facility. Interest rates are variable and at December 31, 1995, ranged from 5.50 percent to 7.10 percent. As of December 31, 1995, Nantahala Power and Light Company had $33,000,000 in senior notes maturing in 2011 and 2012. The two notes carry fixed interest rates of 9.21 percent and 7.45 percent and require monthly payments of principal beginning in 1997 and 1998, respectively.

The annual maturities of consolidated long-term debt, including capitalized lease principal payments through 2000, are $12,071,000 in 1996; $215,476,000 in 1997; $63,097,000 in 1998; $473,326,000 in 1999; and $206,583,000 in 2000.

NOTE 10. FINANCIAL INSTRUMENTS

The carrying amounts of "Cash," "Short-term investments," and "Notes payable" on the Consolidated Balance Sheets approximate fair value primarily because of the short maturities of these instruments. "Other investments" substantially consist of notes receivable issued at fixed rates with maturities up to 30 years for which there are no quoted market prices. Due to the numerous outstanding notes, it was not practicable or cost beneficial for the Company to estimate the fair value of these instruments. The majority of estimated fair value amounts of long-term debt and preferred stock as disclosed below were obtained from independent parties. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 1995 and 1994, are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

External funds have been established, as required by the Nuclear Regulatory Commission, as a mechanism to fund certain costs of nuclear decommissioning. (See Note 14.) Currently, these nuclear decommissioning trust funds are invested in U.S. stocks, bonds and cash equivalents. "Nuclear decommissioning trust funds" are presented on the Consolidated Balance Sheets at amounts that approximate fair value.

The carrying amounts and estimated fair values of long-term debt and preferred stocks are as follows (dollars in thousands):

	December 31, 1995		December 31, 1994	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$3,777,672	$3,879,000	$3,696,260	$3,392,000
Preferred stock	$ 684,000	$ 689,000	$ 781,000	$ 697,000

In order to obtain variable rate financing at an attractive cost, the Company entered into interest rate swap agreements associated with the November 29, 1994, issuance of $200 million aggregate principal amount of its First and Refunding Mortgage Bonds, 8% Series B due 1999 and the August 21, 1995, issuance of $100 million aggregate principal amount of its First and Refunding Mortgage Bonds, 7½% Series B due 2025. The interest rate swaps are reset quarterly based upon the London Interbank Offered Rate (LIBOR). As a result of the interest rate swap contracts, interest expense on the Consolidated Statements of Income is recognized at the weighted average rate for the year tied to the LIBOR rate.

The weighted average rates are as follows (dollars in thousands):

Series	Year Due	Face Value	Weighted Average Rate 1995	Weighted Average Rate 1994
8% Series B	1999	$200,000	6.14%	5.95%
7½% Series B	2025	$100,000	7.06%	—

NOTE 10. FINANCIAL INSTRUMENTS — Continued

The Company also entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Japanese yen associated with various steam generator contracts. The hedge transaction, with a notional amount of approximately $25 million at December 31, 1994, was fully liquidated by November 1995. The Company recorded any gains or losses associated with the hedge as an adjustment to the capitalized cost of the steam generators.

Duke Energy Group, Inc. has entered into a hedge transaction to offset currency fluctuations between the U.S. dollar and the Chilean peso associated with expected equity contributions over the next two years to a joint venture. The hedge transaction had a notional amount of approximately $17 million at December 31, 1995. Duke Energy Group, Inc. records any gains or losses associated with the hedge as an adjustment to investments in joint ventures.

NOTE 11. INVESTMENTS IN JOINT VENTURES

Certain investments in joint ventures are accounted for by the equity method. The Company's ownership in domestic and international joint ventures is 50 percent or less. The Company's proportionate share of net income in joint ventures for the years ended December 31, 1995, 1994 and 1993 was $9,237,000, $7,049,000 and $2,601,000, respectively. These amounts are reflected in "Operating revenues" on the Consolidated Statements of Income.

A summary of assets and liabilities of joint ventures follows (dollars in thousands):

	December 31, 1995		December 31, 1994	
	Total	Company's Proportionate Share	Total	Company's Proportionate Share
Assets of joint ventures	$1,445,600	$351,376	$1,117,449	$272,836
Liabilities of joint ventures	$ 615,452	$188,102	$ 504,029	$164,506

Of the $615,452,000 and $504,029,000 of total liabilities outstanding at December 31, 1995 and 1994, respectively, $528,289,000 and $407,605,000 represent non-recourse debt at December 31, 1995 and 1994, respectively, for which the Company bears no responsibility beyond the loss of its investment and loans made to certain joint ventures in the event the joint venture defaults on the debt. These loans were approximately $23,170,000 at December 31, 1995.

NOTE 12. RETIREMENT BENEFITS

A. Retirement Plan

The Company and its operating subsidiaries, with the exception of Nantahala Power and Light Company, which maintains its own retirement plans, have a non-contributory, defined benefit retirement plan covering substantially all their employees. The benefit is based upon an age-related formula which takes into account years of creditable service and the employee's average compensation based upon the highest compensation during a consecutive sixty-month period. The benefit is reduced by an adjustment which is based upon the employee's social security wages. Normal retirement age under the Plan is age 65; however, early retirement benefits are payable as early as age 55 with 10 years of creditable service or age 51 if the employee has at least 30 years of creditable service. The Company's policy is to fund pension costs as accrued. During 1994, the Company made additional contributions of $30,000,000 to enhance the funded position of the plan.

NOTE 12. RETIREMENT BENEFITS — Continued

Net periodic pension cost for the years ended December 31, 1995, 1994 and 1993, include the following components (dollars in thousands):

	1995		1994		1993	
Service cost benefit earned during the year		$ 46,402		$ 43,098		$ 39,514
Interest cost on projected benefit obligation		111,110		96,521		93,347
Actual return on plan assets	(253,314)		(6,138)		(117,898)	
Amount deferred for recognition	144,022		(86,995)		35,652	
Expected return on plan assets		(109,292)		(93,133)		(82,246)
Net amortization		6,161		7,657		4,137
Net periodic pension cost		$ 54,381		$ 54,143		$ 54,752

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1995 and 1994, is as follows (dollars in thousands):

	1995	1994
Accumulated benefit obligation:		
Vested benefits	$(1,289,459)	$(1,070,355)
Nonvested benefits	(6,216)	(4,420)
Accumulated benefit obligation	$(1,295,675)	$(1,074,775)
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	$ 1,424,148	$ 1,167,158
Projected benefit obligation	(1,596,747)	(1,368,740)
Unrecognized net experience loss	286,837	319,519
Unrecognized prior service cost reduction	(35,039)	(38,872)
Remaining unrecognized transitional obligation	801	935
Pre-funded pension cost	$ 80,000	$ 80,000

In determining the projected benefit obligation, the weighted-average assumed discount rate used was 7.50 percent in 1995, 8.25 percent in 1994 and 7.50 percent in 1993. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 4.75 percent in 1995, 5.40 percent in 1994 and 4.50 percent in 1993. The expected long-term rate of return on plan assets used in determining pension cost was 9.00 percent in 1995, 9.00 percent in 1994 and 8.40 percent in 1993.

During 1995, the Company offered to certain employees an Enhanced Vested Benefits program (EVB). The Company recorded an additional one-time expense for special termination benefits associated with EVB of approximately $42,196,000, including $21,600,000 of additional retirement plan costs.

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 (NP&L), which has maintained its own postretirement benefit plans, currently provide certain health care and life insurance benefits for retired employees. However, NP&L employees who retire after January 1, 1996, will be covered by Duke Power Company's postretirement benefit plan. 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,

NOTE 12. RETIREMENT BENEFITS — Continued

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 $23,000,000 into these funding mechanisms in 1995 and $12,269,000 in 1994.

Net periodic postretirement benefit cost for the years ended December 31, 1995, 1994 and 1993, include the following components (dollars in thousands):

	1995		1994		1993	
Service cost benefit earned during the year		$ 5,874		$ 5,415		$ 4,974
Interest cost on accumulated postretirement benefit obligation		27,201		25,321		25,482
Actual return on plan assets	(14,726)		(1,451)		(4,143)	
Amount deferred for recognition	7,260		(3,469)		334	
Expected return on plan assets		(7,466)		(4,920)		(3,809)
Straight-line — 20 year amortization of transitional obligation		13,293		13,293		13,479
Other amortization		555		366		278
Net periodic postretirement benefit cost		$39,457		$39,475		$40,404

A reconciliation of the funded status of the plan to the amounts recognized in the Consolidated Balance Sheets as of December 31, 1995 and 1994, is as follows (dollars in thousands):

	1995		1994	
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		$ 105,506		$ 69,987
Actives eligible to retire	(25,780)		(11,902)	
Actives not eligible to retire	(97,389)		(90,499)	
Retirees and surviving spouses	(253,688)		(239,978)	
Accumulated postretirement benefit obligation		(376,857)		(342,379)
Unrecognized prior service cost		712		783
Unrecognized net experience loss		25,955		14,448
Unrecognized transitional obligation		212,695		225,988
(Accrued) postretirement benefit cost		$ (31,989)		$ (31,173)

In determining the accumulated postretirement benefit obligation (APBO), the weighted-average assumed discount rate used was 7.50 percent in 1995, 8.25 percent in 1994 and 7.50 percent in 1993. The assumed increase in future compensation level is determined on an age-related basis. The weighted-average salary increase was 4.75 percent in 1995, 5.40 percent in 1994 and 4.50 percent in 1993. The expected long-term rate of return on 401(h) assets used in determining postretirement benefits cost was 9.00 percent in 1995, 9.00 percent in 1994 and 8.40 percent in 1993. For Retired Lives Reserve assets, 8.00 percent was used in 1995, 6.50 percent in 1994 and 7.13 percent in 1993.

The assumed medical inflation rate was approximately 10.5 percent in 1995. This rate decreases by 0.5 percent to 1.0 percent per year until a rate of 5.5 percent is achieved in the year 2001, which remains fixed thereafter.

NOTE 12. RETIREMENT BENEFITS — Continued

A 1.0 percent increase in the medical and dental trend rates produces a 4.81 percent ($1,589,000) increase in the aggregate service and interest cost. The increase in the APBO attributable to a 1.0 percent increase in the medical and dental trend rates is 9.22 percent ($38,281,000) as of December 31, 1995.

NOTE 13. COMMITMENTS AND CONTINGENCIES

A. Construction Program

Projected construction and nuclear fuel costs for Duke Power's electric operations, both including allowance for funds used during construction, are $2.3 billion and $661 million, respectively, for 1996 through 2000. These projections are subject to periodic review and revisions. Actual construction and nuclear fuel costs and capital expenditures incurred may vary from such estimates. Cost variances are due to various factors, including revised load estimates, environmental matters and cost and availability of capital.

Projected capital expenditures of subsidiaries and diversified activities are $1.0 billion for 1996 through 2000. These projections are subject to periodic review and revisions and may vary significantly as the business plans of the Associated Enterprises Group evolve to meet the opportunity presented by its markets.

B. Nuclear Insurance

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

Pursuant to the Price-Anderson Act, the Company is required to insure against public liability claims resulting from nuclear incidents to the full limit of liability of approximately $8.9 billion. The maximum required private primary insurance of $200 million has been purchased along with a like amount to cover certain worker tort claims. The remaining amount, currently $8.7 billion, which will be increased by $79.3 million as each additional commercial nuclear reactor is licensed, has been provided through a mandatory industry-wide excess secondary insurance program of risk pooling. The $8.7 billion could also be reduced by $79.3 million for certain nuclear reactors that are no longer operational and may be exempted from the risk pooling insurance program. Under this program, licensees could be assessed retrospective premiums to compensate for damages in the event of a nuclear incident at any licensed facility in the nation. If such an incident occurs and public liability damages exceed primary insurances, licensees may be assessed up to $79.3 million for each of their licensed reactors, payable at a rate not to exceed $10 million a year per licensed reactor for each incident. The $79.3 million amount is subject to indexing for inflation and may be subject to state premium taxes. This amount is further subject to a surcharge of 5 percent (which is included in the above $8.7 billion figure) if funds are insufficient to pay claims and associated costs. If retrospective premiums were to be assessed, the other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of such assessment.

The Company is a member of Nuclear Mutual Limited (NML), which provides $500 million in primary property damage coverage for each of the Company's nuclear facilities. If NML's losses ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $36 million. This amount represents 5 times the Company's annual premium to NML. The other joint owners of Catawba are obligated to assume their pro rata share of any liability for retrospective premiums and other premium assessments resulting from the NML policies applicable to Catawba.

The Company is also a member of Nuclear Electric Insurance Limited (NEIL) and purchases insurance through NEIL's excess property, decontamination and decommissioning liability insurance program. NEIL provides excess insurance coverage of $2.25 billion for the Catawba Nuclear Station and $1.5 billion for each of the Oconee and McGuire Nuclear Stations. If losses ever exceed the accumulated funds available to NEIL for the excess property, decontamination and decommissioning liability program, the Company will be liable, on a pro rata basis, for additional assessments of up to $61 million. This

NOTE 13. COMMITMENTS AND CONTINGENCIES — Continued

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 participates in a NEIL program that provides insurance for the increased cost of generation and/or purchased power resulting from an accidental outage of a nuclear unit. Each unit of the Oconee, McGuire and Catawba Nuclear Stations is insured for up to approximately $3.5 million per week, after a 21-week deductible period, with declining amounts per unit where more than one unit is involved in an accidental outage. Coverages continue at 100 percent for 52 weeks and 80 percent for the next 104 weeks. If NEIL's losses for this program ever exceed its reserves, the Company will be liable, on a pro rata basis, for additional assessments of up to $30 million. This amount represents 5 times the Company's annual premium to NEIL for insurance for the increased cost of generation and/or purchased power resulting from an accidental outage 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 Company and North Carolina Municipal Power Agency Number 1 and Piedmont Municipal Power Agency, two of the four other joint owners of the Catawba Nuclear Station, entered into a settlement in September 1995 which resolved outstanding issues related to how certain calculations affecting bills under the Catawba joint ownership contractual agreements should be performed. The settlement was approved by the North Carolina Utilities Commission on January 16, 1996 and the Public Service Commission of South Carolina on January 23, 1996. As part of the settlement, the Company agreed to purchase additional megawatts (MW) of Catawba capacity during the period 1996 through 1999 and remove certain restrictions related to sales of surplus energy by these two joint owners. The additional capacity purchases are 215 MW in 1996, 165 MW in 1997, 120 MW in 1998 and 100 MW in 1999. The Company expects to recover the costs associated with this settlement as part of the purchased capacity levelization, consistent with prior orders of the retail regulatory commissions. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company and all four of the other joint owners of the Catawba Nuclear Station entered into settlement agreements in 1994 which resolved all issues in contention in arbitration proceedings related to the Catawba joint ownership contractual agreements. The basic contention in each proceeding was that certain calculations affecting bills under these agreements should be performed differently. These items are covered by the agreements between the Company and the other Catawba joint owners which have been previously approved by the Company's retail regulatory commissions. (For additional information, see Note 3.) In 1994, the Company settled its cumulative net obligation through 1993 of approximately $205 million related to these settlement agreements. Billings for 1994 and later years will conform to the settlement agreements, which have been approved by the Company's retail regulatory commissions. Because the Company expects the costs associated with these settlements to be recovered as part of the purchased capacity levelization, which has been approved by the Company's retail regulatory commissions, the Company included approximately $205 million as an increase to "Purchased capacity costs" on its Consolidated Balance Sheets in 1994. Therefore, the Company believes these matters should not have a material adverse effect on the results of operations or financial position of the Company.

The Company is also involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Where appropriate, the Company has made accruals in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies," in order to provide for such matters. Management is of the opinion that the final disposition of these proceedings will not have a material adverse effect on the results of operations or financial position of the Company.

NOTE 14. NUCLEAR DECOMMISSIONING COSTS

Estimated site-specific nuclear decommissioning costs, including the cost of decommissioning plant components not subject to radioactive contamination, total approximately $1.3 billion stated in 1994 dollars based on decommissioning studies completed in 1994. This amount includes the Company's 12.5 percent ownership in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the North Carolina Utilities Commission and the Public Service Commission of South Carolina have granted the Company recovery of estimated decommissioning costs through retail rates over the expected remaining service periods of the Company's nuclear plants. Such estimates presume each unit will be decommissioned as soon as possible following the end of their license life. Although subject to extension, the current operating licenses for the Company's nuclear units expire as follows: Oconee 1 and 2 — 2013, Oconee 3 — 2014; McGuire 1 — 2021, McGuire 2 — 2023; and Catawba 1 — 2024, Catawba 2 — 2026.

The Nuclear Regulatory Commission issued a rule-making in 1988 which requires an external mechanism to fund the estimated cost to decommission certain components of a nuclear unit subject to radioactive contamination. In addition to the required external funding, the Company maintains an internal reserve to provide for decommissioning costs of plant components not subject to radioactive contamination. During 1995, the Company expensed approximately $56,470,000 which was contributed to the external funds and accrued an additional $1,319,000 to the internal reserve. Nuclear units are depreciated at a rate of 4.70 percent, of which 1.61 percent is for decommissioning. The balance of the external funds as of December 31, 1995, was $273,466,000. The balance of the internal reserve as of December 31, 1995, was $206,155,000 and is reflected in accumulated depreciation and amortization on the Consolidated Balance Sheets. Management's opinion is that the decommissioning costs being recovered through rates, when coupled with assumed after-tax fund earnings of 5.5 percent to 5.9 percent, are currently sufficient to provide for the cost of decommissioning.

NOTE 15. RECLASSIFICATION

In the Consolidated Statements of Income and Consolidated Statements of Cash Flows, certain 1993 information has been reclassified to conform with 1994 classifications.

INDEPENDENT AUDITORS' REPORT

Duke Power Company:

We have audited the consolidated financial statements of Duke Power Company and subsidiaries (the Company) listed in the accompanying index for Item 8. Our audits also included the consolidated financial statement schedule listed in the accompanying index. These financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and consolidated financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 1995 and 1994, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1995 in conformity with generally accepted accounting principles. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP

Charlotte, North Carolina
February 9, 1996

RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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

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

JEFFREY L. BOYER
Controller

QUARTERLY FINANCIAL DATA

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	Dollars in Thousands (except per-share data)				
1995 by quarter					
Operating revenues	$1,111,065	$1,052,403	$1,379,978	$1,133,238	$4,676,684
Operating income	$ 369,414	$ 263,876	$ 504,507	$ 211,254	$1,349,051
Net income	$ 201,276	$ 137,523	$ 285,200	$ 90,539	$ 714,538
Earnings per share	$ 0.92	$ 0.61	$ 1.33	$ 0.39	$ 3.25
1994 by quarter					
Operating revenues	$1,099,002	$1,083,310	$1,272,525	$1,034,076	$4,488,913
Operating income	$ 326,584	$ 242,419	$ 430,861	$ 179,962	$1,179,826
Net income	$ 173,617	$ 128,002	$ 243,741	$ 93,516	$ 638,876
Earnings per share	$ 0.79	$ 0.56	$ 1.13	$ 0.40	$ 2.88

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

SUBSIDIARIES AND DIVERSIFIED ACTIVITIES HIGHLIGHTS

During 1994, the Company reorganized, placing all its subsidiaries and diversified activities into the Associated Enterprises Group (AEG). AEG includes the following:

- **Church Street Capital Corp.** (CSCC) manages investment funds, serves as the parent company and provides equity funding and credit enhancement for the non-electric operating subsidiaries. CSCC investment highlights are as follows (dollars in thousands):

  Short-term investments and marketable securities

1995	1994	1993
$76,300	$170,642	$155,871

  Investment income (after tax) (a)

1995	1994	1993
$4,783	$7,562	$3,548

- **Crescent Resources, Inc.** is engaged in real estate development and forest management.
- **Duke Energy Group, Inc.** develops, owns and manages investments in electric power facilities, both nationally and internationally, and markets electric power and natural gas.
- **Duke Engineering & Services, Inc.** markets engineering, construction, quality assurance, consulting and other engineering-related services for facilities other than coal-fired generating plants, both nationally and internationally.
- **Duke/Fluor Daniel,** a joint venture with Fluor Daniel, Inc., provides engineering, construction, and support of operating and maintenance activities, primarily for coal-fired generating plants, both nationally and internationally.
- **Duke Merchandising** sells and services quality appliances and electronics primarily to Duke Power customers.
- **DukeNet Communications, Inc.** develops and manages communication systems.
- **Duke Water Operations** serves areas of Anderson, South Carolina, and Rutherfordton, North Carolina.
- **Nantahala Power and Light Company** provides electric service to a five-county area in western North Carolina by its operation of eleven hydroelectric stations and purchase of supplemental power.

Operating Results

	Year ended December 31,		
	1995	1994	1993
	Dollars in Thousands		
Operating revenues			
Crescent Resources, Inc.	$ 85,361	$ 64,724	$ 46,784
Duke Energy Group, Inc. (b)	10,017	9,478	6,033
Nantahala Power and Light Company (c)	62,510	68,595	67,142
All Other Business Units (d)	141,337	109,932	106,340
Total Associated Enterprises Group	$299,225	$252,729	$226,299
Operating income			
Crescent Resources, Inc.	$ 63,973	$ 46,236	$ 30,004
Duke Energy Group, Inc.	(1,422)	(1,035)	(2,929)
Nantahala Power and Light Company	9,262	12,224	8,844
All Other Business Units (d)	20,407	15,506	1,939
Total Associated Enterprises Group	$ 92,220	$ 72,931	$ 37,858
Net income			
Crescent Resources, Inc.	$ 35,500	$ 26,525	$ 16,327
Duke Energy Group, Inc. (e)	170	5,749	(1,949)
Nantahala Power and Light Company	4,037	6,169	4,261
All Other Business Units (d)	14,550	13,593	2,876
Total Associated Enterprises Group	$ 54,257	$ 52,036	$ 21,515

Financial Position

	December 31,		
	1995	1994	1993
	Dollars in Thousands		
Total assets			
Crescent Resources, Inc.	$381,073	$294,175	$219,206
Duke Energy Group, Inc. (f)	149,391	110,656	144,499
Nantahala Power and Light Company	144,069	125,883	107,872
All Other Business Units (d)	283,774	279,430	265,977
Total Associated Enterprises Group	$958,307	$810,144	$737,554
Total liabilities			
Crescent Resources, Inc.	$185,996	$134,574	$ 86,172
Duke Energy Group, Inc.	9,783	4,672	31,816
Nantahala Power and Light Company	86,691	72,542	60,700
All Other Business Units (d)	43,498	22,312	30,902
Total Associated Enterprises Group	$325,968	$234,100	$209,590

Cash Flows

	Year ended December 31,		
	1995	1994	1993
	Dollars in Thousands		
Cash provided by (used in) operating activities			
Crescent Resources, Inc.	$ 40,144	$ 37,691	$ 36,254
Duke Energy Group, Inc.	(3,521)	(6,614)	(1,438)
Nantahala Power and Light Company	8,419	12,817	14,869
All Other Business Units (d)	1,769	10,589	8,795
Total Associated Enterprises Group	$ 46,811	$ 54,483	$ 58,480
Cash provided by investing activities			
Crescent Resources, Inc.	$ 5,910	$ 2,524	$ 1,310
Duke Energy Group, Inc. (g)	14,253	40,740	28,785
Nantahala Power and Light Company	—	—	—
All Other Business Units (h)	97,793	5,100	21,377
Total Associated Enterprises Group	$117,956	$ 48,364	$ 51,472
Cash used in investing activities			
Crescent Resources, Inc.	$ 84,603	$ 78,689	$ 43,444
Duke Energy Group, Inc.	44,776	19,575	116,498
Nantahala Power and Light Company	23,944	23,989	19,254
All Other Business Units (i)	66,768	18,500	1,450
Total Associated Enterprises Group	$220,091	$140,753	$180,646
Cash provided by (used in) financing activities (j)			
Crescent Resources, Inc. (k)	$ 38,521	$ 37,589	$ 945
Duke Energy Group, Inc. (l)	—	—	—
Nantahala Power and Light Company	15,536	10,896	3,2[illegible]
All Other Business Units (m)	5,302	(6,993)	71,53[illegible]
Total Associated Enterprises Group	$ 59,359	$ 41,492	$ 75,688

Other Information

	December 31,		
	1995	1994	1993
Full-time employees at year-end			
Crescent Resources, Inc.	94	89	77
Duke Energy Group, Inc.	43	35	24
Nantahala Power and Light Company	182	184	194
All Other Business Units	1,036	703	755
Total Associated Enterprises Group	1,355	1,011	1,050

(a) Earnings for 1995, 1994 and 1993 exclude elimination of intercompany profits of $59,000, $49,000 and $509,000, respectively.

(b) Includes Duke Energy Group, Inc.'s allocable share of net income from joint ventures. (See Note 11.)

(c) Nantahala Power and Light Company's Operating revenues include revenues from the sale of electricity to Duke Power of $1,205,000, $12,131,000 and $13,683,000 for 1995, 1994 and 1993, respectively.

(d) All Other Business Units amounts include Associated Enterprises Group intercompany eliminations.

(e) 1994 includes a gain of $4,800,000, after tax, from the sale of preferred stock.

(f) Includes Duke Energy Group, Inc.'s investments in joint ventures. (See Note 11.)

(g) 1994 includes proceeds from the sale of preferred stock of $32,468,000 and debt securities of $3,360,000. 1993 include[illegible] proceeds from the sale of debt securities of $19,654,000.

(h) 1995 and 1993 include the net change in short-term investments for the period of $56,392,000 and $20,653,000, respectively. Also, 1995 includes proceeds from the sale of a dividend capture program of $40,953,000.

(i) 1994 includes the net change in short-term investments for the period of $12,060,000.

(j) Excludes capital infusion and return of capital transactions between parent, Church Street Capital Corp., and its subsidiaries.

(k) 1993 excludes capital infusion from parent, Church Street Capital Corp., of $6,000,000.

(l) 1995 and 1993 exclude net capital infusions from parent, Church Street Capital Corp., of $33,455,000 and $91,864,000, respectively. 1994 excludes net return of capital to Church Street Capital Corp. of $12,100,000.

(m) 1993 includes capital infusion from Duke Power to Church Street Capital Corp. of $75,000,000.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Description	Balance Beginning of Year	Balance End of Year
	Dollars in Thousands	
For the Year Ended December 31, 1995		
Reserves Related to Assets on Balance Sheet	$ 8,059	$ 7,774
Other Reserves		
Operating Reserves (1)	154,722	176,098
For the Year Ended December 31, 1994		
Reserves Related to Assets on Balance Sheet	10,353	8,059
Other Reserves		
Operating Reserves (1)	107,477	154,722
For the Year Ended December 31, 1993		
Reserves Related to Assets on Balance Sheet	10,730	10,353
Other Reserves		
Operating Reserves (1)	78,103	107,477

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

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

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

PART III.

Item 10. ***Directors and Executive Officers of the Registrant.***

Information for this item concerning directors of the Company is set forth in the sections entitled "Election of Directors", "Information Regarding the Board of Directors" and "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1996 annual meeting of shareholders, which are being incorporated herein by reference.

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

Item 11. ***Executive Compensation.***

Information for this item is set forth in the section entitled "Executive Compensation" in the proxy statement of the Company relating to its 1996 annual meeting of shareholders, which is being incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management.***

Information for this item is set forth in the section entitled "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1996 annual meeting of shareholders, which is being incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions.***

Information for this item is set forth in the sections entitled "Information Regarding the Board of Directors" and "Common Stock Ownership of Certain Beneficial Owners and Management" in the proxy statement of the Company relating to its 1996 annual meeting of shareholders, which are being incorporated herein by reference.

PART IV.

Item 14. ***Exhibits, Consolidated Financial Statement Schedules, and Reports on Form 8-K.***

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Consolidated Financial Statements

Consolidated Statements of Income for the Three Years Ended December 31, 1995

Consolidated Statements of Retained Earnings for the Three Years Ended December 31, 1995

Consolidated Statements of Cash Flows for the Three Years Ended December 31, 1995

Consolidated Balance Sheets — December 31, 1995 and 1994

Notes to Consolidated Financial Statements

Selected Quarterly Financial Data (unaudited)

Consolidated Financial Statement Schedule

Schedule II — Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 1995

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

(b) Reports on Form 8-K

No reports on Form 8-K were filed during the last quarter of 1995.

(c) Exhibits — See Exhibit Index on page 58.

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Charlotte and State of North Carolina on the 12th day of March, 1996.

DUKE POWER COMPANY
(Registrant)

By: W. H. GRIGG
Chairman of the Board and Chief Executive Officer

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

Signature	Title	Date
W. H. GRIGG	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	March 12, 1996
RICHARD J. OSBORNE	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 12, 1996
JEFFREY L. BOYER	Controller (Principal Accounting Officer)	March 12, 1996
G. ALEX BERNHARDT CRANDALL C. BOWLES ROBERT J. BROWN W. A. COLEY STEVE C. GRIFFITH, JR. W. H. GRIGG GEORGE DEAN JOHNSON, JR. W. W. JOHNSON MAX LENNON JAMES G. MARTIN BUCK MICKEL R. B. PRIORY RUSSELL M. ROBINSON, II	A Majority of the Directors	March 12, 1996

ELLEN T. RUFF, by signing her name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

/s/ ELLEN T. RUFF
Ellen T. Ruff, Attorney-In-Fact

EXHIBIT INDEX

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

Exhibit Number	
3-A	—Restated Articles of Incorporation of registrant, dated as of October 6, 1993 (filed with Form S-3, File No. 33-50617, effective October 20, 1993, as Exhibit 4(A)).
3-B	—Articles of Amendment of registrant dated November 1, 1993, relating to the 6.375% Cumulative Preferred Stock A, 1993 Series (filed with Form S-3, No. 33-52479, effective March 29, 1994, as Exhibit 4(B)).
*3-C	—By-Laws of registrant, as amended.
4-B-1	—First and Refunding Mortgage from registrant to Guaranty Trust Company of New York, Trustee, dated as of December 1, 1927 (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(a)).
4-B-2	—Supplemental Indenture, dated as of March 12, 1930, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(b)).
4-B-5	—Supplemental Indenture, dated as of September 1, 1936, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(e)).
4-B-6	—Supplemental Indenture, dated as of January 1, 1941, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(f)).
4-B-7	—Supplemental Indenture, dated as of April 1, 1944, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(g)).
4-B-8	—Supplemental Indenture, dated as of September 1, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-7224, effective October 15, 1947, as Exhibit 7(h)).
4-B-9	—Supplemental Indenture, dated as of September 8, 1947, supplementing said Mortgage (filed with Form S-1, File No. 2-10401, effective August 21, 1953, as Exhibit 4-B-9).
4-B-10	—Supplemental Indenture, dated as of February 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-7808, effective February 3, 1949, as Exhibit 7(j)).
4-B-11	—Supplemental Indenture, dated as of March 1, 1949, supplementing said Mortgage (filed with Form S-1, File No. 2-8877, effective April 6, 1951, as Exhibit 7(k)).
4-B-14	—Supplemental Indenture, dated as of October 1, 1954, supplementing said Mortgage (filed with Form S-9, File No. 2-11297, effective December 30, 1954, as Exhibit 2-B-14).
4-B-17	—Supplemental Indenture, dated as of January 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-18).
4-B-18	—Supplemental Indenture, dated as of February 1, 1960, supplementing said Mortgage (filed with Form 10, effective June 29, 1961, as Exhibit 3-B-19).
4-B-21	—Supplemental Indenture, dated as of June 15, 1964, supplementing said Mortgage (filed with Form S-1, File No. 2-25367, effective August 3, 1966, as Exhibit 4-B-20).
4-B-23	—Supplemental Indenture, dated as of April 1, 1967, supplementing said Mortgage (filed with Form S-9, File No. 2-28023, effective February 15, 1968, as Exhibit 2-B-25).
4-B-24	—Supplemental Indenture, dated as of February 1, 1968, supplementing said Mortgage (filed with Form S-9, File No. 2-31304, effective January 21, 1969, as Exhibit 2-B-26).
4-B-48	—Supplemental Indenture, dated as of September 1, 1983, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-48).
4-B-49	—Supplemental Indenture, dated as of September 1, 1984, supplementing said Mortgage (filed with Form S-3, File No. 2-95931, effective April 1, 1985, as Exhibit 4-B-49).
4-B-56	—Supplemental Indenture, dated as of February 15, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1986, File No. 1-4928, as Exhibit 4-B-56).
4-B-58	—Supplemental Indenture, dated as of October 1, 1987, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1987, File No. 1-4928, as Exhibit 4-B-58).
4-B-60	—Supplemental Indenture, dated as of March 1, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-60).
4-B-62	—Supplemental Indenture, dated as of May 15, 1990, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-62).
4-B-63	—Supplemental Indenture, dated as of March 1, 1991, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1990, File No. 1-4928, as Exhibit 4-B-63).

Exhibit Number	
B-64	—Supplemental Indenture, dated as of July 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-64).
4-B-65	—Supplemental Indenture, dated as of December 1, 1991, supplementing said Mortgage (filed with Form S-3, File No. 33-45501, effective February 13, 1992, as Exhibit 4-B-65).
4-B-66	—Supplemental Indenture, dated as of March 1, 1992, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1991, File No. 1-4928, as Exhibit 4-B-66).
4-B-67	—Supplemental Indenture, dated as of June 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-67).
4-B-68	—Supplemental Indenture, dated as of July 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-50592, effective August 11, 1992, as Exhibit 4-B-68).
4-B-69	—Supplemental Indenture, dated as of September 1, 1992, supplementing said Mortgage (filed with Form S-3, File No. 33-53308, effective November 24, 1992, as Exhibit 4-B-69).
4-B-70	—Supplemental Indenture, dated as of February 1, 1993, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, as Exhibit 4-B-70).
4-B-71	—Supplemental Indenture, dated as of March 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-59448, effective March 17, 1993, as Exhibit 4-B-71).
4-B-72	—Supplemental Indenture, dated as of April 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-72).
4-B-73	—Supplemental Indenture, dated as of May 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-73).
4-B-74	—Supplemental Indenture, dated as of June 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-74).
4-B-75	—Supplemental Indenture, dated as of July 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-75).
4-B-76	—Supplemental Indenture, dated as of August 1, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-76).
4-B-77	—Supplemental Indenture, dated as of August 20, 1993, supplementing said Mortgage (filed with Form S-3, File No. 33-50543, effective October 20, 1993, as Exhibit 4-B-77).
B-78	—Supplemental Indenture, dated as of May 1, 1994, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1994, File No. 1-4928, as Exhibit 4-B-78).
4-B-79	—Supplemental Indenture, dated as of November 1, 1994, supplementing said Mortgage (filed with Form 10-K for the year ended December 31, 1994, File No. 1-4928, as Exhibit 4-B-79).
*4-B-80	—Supplemental Indenture, dated as of August 1, 1995, supplementing said Mortgage.
4-C	—Instrument of Resignation, Appointment and Acceptance among Duke Power Company, Morgan Guaranty Trust Company of New York, as Trustee, and Chemical Bank, as Successor Trustee, dated as of August 30, 1994 (filed with Form 10-K for the year ended December 31, 1994, File No. 1-4928, as Exhibit 4-C).
10-A	—Agreement, dated March 6, 1978, between the registrant and the North Carolina Municipal Power Agency No. 1 (filed with Form 8-K for the month of March 1978, File No. 1-4928).
10-B	—Agreement, dated August 1, 1980, between the registrant and Piedmont Municipal Power Agency (filed with Form 8-K for the month of August 1980, File No. 1-4928).
10-C	—Agreement, dated October 14, 1980 between the registrant and North Carolina Electric Membership Corporation (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-D	—Agreement, dated October 14, 1980 between the registrant and Saluda River Electric Cooperative, Inc. (filed with Form 10-Q for the quarter ended September 30, 1980, File No. 1-4928).
10-E†	—Employees' Stock Ownership Plan.
10-F††	—Employee Incentive Plan.
10-G††	—1993 Executive Long-Term Incentive Plan.
10-H†	—Supplemental Security Plan.
10-I†	—Stock Purchase-Savings Program for Employees.
10-J†	—Employees' Retirement Plan.
10-K†	—Supplemental Retirement Plan.
10-L†	—Compensation Deferral Plan.
10-M†	—Compensation Deferral Plan for Outside Directors.
10-N†	—Retirement Plan for Outside Directors.
0-O†	—Supplementary Defined Contribution Plan for Employees.
10-P†	—Directors' Charitable Giving Program.

Exhibit Number	
10-Q†	—Vacation Banking Plan.
10-R†	—Estate Conservation Plan.
10-S†	—Supplemental Insurance Plan.
10-T†	—Group Life Insurance Plan.
10-U†	—Stock Ownership Plan for Nonemployee Directors.
10-V†††	—Executive Short-Term Incentive Plan.
10-W†††	—Executive Long-Term Incentive Plan.
*12	—Computation of Ratio of Earnings to Fixed Charges.
*23	—Consent of Independent Auditors.
*24(a)	—Power of attorney authorizing Ellen T. Ruff and others to sign the annual report on behalf of the registrant and certain of its directors and officers.
*24(b)	—Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.
*27	—Financial Data Schedule.

† Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1992, File No. 1-4928, under the same exhibit number as listed herein.

†† Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1993, File No. 1-4928, under the same exhibit number as listed herein.

††† Compensatory plan or arrangement filed with Form 10-K for the year ended December 31, 1994, File No. 1-4928, under the same exhibit number as listed herein.

EXHIBIT 12

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in Thousands)

	Year Ended December 31,				
	1995	1994	1993	1992	1991
Earnings Before Income Tax	$1,180,979	$1,035,895	$1,036,392	$ 812,053	$ 876,641
Fixed Charges	299,633	278,117	281,428	326,575	310,030
Total	$1,480,612	$1,314,012	$1,317,820	$1,138,628	$1,186,671
Fixed Charges					
Interest on long-term debt	253,058	237,063	243,047	257,149	269,419
Other interest	21,143	16,814	17,704	47,239	23,947
Amortization of debt discount, premium and expense	16,239	16,340	13,300	8,497	5,243
Interest component of rentals	9,193	7,900	7,377	13,690	11,421
Fixed Charges	$ 299,633	$ 278,117	$ 281,428	$ 326,575	$ 310,030
Ratio of Earnings to Fixed Charges	4.94	4.72	4.68	3.49	3.83

CITIZENSHIP

DUKE POWER

SERVICE