CENTERIOR ENERGY

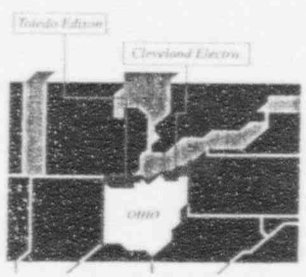
ANNUAL REPORT 1993

"...the single greatest challenge in our history—making the transition from a traditional utility to a more competitive, market-driven business..."

CONTENTS

HIGHLIGHTS

A long-term strategic action plan was developed to guide us through the year 2001. ● We wrote off our investment in Perry Unit 2 and certain deferred charges for a total of $1.023 billion, after taxes. ● Our common stock dividend was reduced to an indicated annual rate of $0.80 per share in January 1994. ● Over 1,500 employees accepted voluntary early retirement in 1993, resulting in a 19% reduction in employees from year-end 1992. ● Davis-Besse continued to operate as one of the nation's best performing nuclear power plants and received its highest marks ever in the Nuclear Regulatory Commission's Systematic Assessment of Licensee Performance. ● A two-year course of action plan was developed and implemented to improve substantially the performance of Perry Unit 1. ● Cleveland Electric reached an agreement that favorably resolved a municipalization threat in the City of Brook Park. ● Voters in the City of Toledo ratified a new franchise agreement for Toledo Edison which runs through the year 2000.



Centerior Energy Corporation was formed in April 1986 upon the affiliation of The Cleveland Electric Illuminating Company and The Toledo Edison Company. With assets of about $11 billion, Centerior Energy is one of the largest electric utility systems in the nation. The Centerior operating companies serve 2.6 million people in a combined service area of 4,200 square miles in Northern Ohio. Centerior Energy is an equal opportunity employer.

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FINANCIAL SUMMARY

Quarterly Range of Common Stock Prices

1993	High	Low
1st Quarter	$20	$18⅜
2nd Quarter	19⅞	17⅝
3rd Quarter	18⅞	17⅜
4th Quarter	17⅞	12

1992	High	Low
1st Quarter	$20	$17⅞
2nd Quarter	18⅝	16⅝
3rd Quarter	17¼	15¾
4th Quarter	20	17⅛

	1993	1992	% Change
Earnings (Loss) Per Share of Common Stock	$ (6.51)	$ 1.50	—
Write-Offs and Other Charges Per Share of Common Stock	$ 7.95	—	—
Earnings Per Share of Common Stock Excluding Write-Offs and Other Charges	$ 1.44	$ 1.50	(4)
Dividends Declared Per Share of Common Stock	$ 1.60	$ 1.60	0
Book Value Per Share of Common Stock at Year End	$12.14	$20.22	(40)
Closing Common Stock Price at Year End	$ 13⅛	$ 19⅝	(33)
Common Stock Share Owners at Year End	163,602	171,255	(4)
Common Stock Shares Outstanding at Year End (millions)	147	143	3
Operating Revenues (millions)	$2,474	$2,438	1
Operating Expenses (millions)	$2,161	$1,901	14
Net Income (Loss) (millions)	$ (943)	$ 212	—
Return on Average Common Stock Equity	(40.3)%	7.4%	—
Return on Average Common Stock Equity Excluding Write-Offs and Other Charges	7.1%	7.4%	—

Kilowatt-hour Sales (Millions of Kilowatt-hours)	1993	1992	% Change
Residential	6,974	6,666	5
Commercial	7,306	7,086	3
Industrial	11,687	11,551	1
Wholesale	3,027	2,814	8
Other	1,022	1,011	1
Total	30,016	29,128	3

	1993	1992	% Change
Employees at Year End	6,748	8,376	(19)

DEAR SHARE OWNER:

THE REGULATORY, LEGISLATIVE AND economic forces impacting Centerior Energy and the electric utility industry brought your Company to a crucial position in 1993. As a result, we took tough and decisive actions to begin to shift our corporate culture and become a powerful, competitive company in the future.

The focus of this shift is a strategic action plan identifying priorities and actions that will guide Centerior Energy over the next eight years. Paramount to the success of this action plan were two decisions that reflect the seriousness of our position. The Board of Directors voted to reduce the quarterly common stock dividend to $0.20 per share and write off $1.023 billion, after taxes, of assets. We notified you in January of these decisions and their meaning within the structure of our plan, which defines our commitment to financial well-being and competitive leadership.

Bob Farling

Many of the past decisions which contributed to Centerior Energy's present status were based on projections of economic growth in our area that did not occur. The economic sluggishness, coupled with increased competitive pressures, continues to exert downward pressure on earnings.

Meanwhile, federal policies continue to move our industry further toward deregulation and unprecedented competition for customers in the once-protected markets of investor-owned utilities.

At Centerior Energy, we are no strangers to competition. As a condition of the licenses granted to operate our nuclear generating plants, we opened our power lines in 1977 to the transmission, or wheeling, of electric power from outside wholesalers to municipal electric systems in our area. However, the next phase of deregulation may well lead to retail wheeling in which any customer with high electricity consumption would have the option of shopping nationally for the lowest-cost electricity.

This situation occurs at a very sensitive time for Centerior Energy. Our electric rates are above the regional and national averages. They reflect the cost of major construction completed in the late 1980s to ensure continued service reliability to our more than one million customers. While these high rates put us at a disadvantage in a competitive environment, our future profits depend on our ability to compete successfully. This was a major factor underlying the strategic review and analysis that led to the development of our eight-year plan. The process had the direct involvement and concurrence of the Board of Directors. We are confident that the resulting plan will be the catalyst that moves Centerior Energy from a traditional regulated utility to a successful, more market-driven business.

Setting the stage for the success of this plan required those very hard decisions that affected the short-term and long-term interests of our share owners.

We recognize that the dividend reduction is a setback to share owners in the short run. However, our earnings projections did not support continuation of the dividend at its former rate, and the Board concluded that it would not be prudent to delay this reduction. Our estimates for future revenues, costs and capital spending requirements indicate that we not only can sustain the dividend at the new rate barring unforeseen circumstances, but we also will have the opportunity to grow the dividend as we achieve our strategic objectives.

These decisions were made now because of the pressures imposed by a number of interrelated factors. Legislative and regulatory decisions have prompted increasing competition while imposing higher operating costs on investor-owned electric utilities. The recent action by several security rating agencies to downgrade the ratings on securities of our operating companies, Cleveland Electric and Toledo Edison, accented our financial difficulties.

We also decided that, once the deferral of expenses and acceleration of benefits under our Rate Stabilization Program are completed in 1995, we should no longer plan to use regulatory accounting practices to the extent we have in the past. As a result, future earnings will be largely cash earnings. This will further move us toward being a more competitive, market-driven company. It also will provide a clearer picture of our progress and strengthen the Company's financial integrity.

Now that these decisions are behind us, we are better positioned to meet today's economic and competitive challenges through implementation of our sweeping strategic action plan. At the heart of the plan are these priorities:

- Maximize share owner return from corporate assets and resources.
- Achieve profitable revenue growth.
- Rank among the nation's top utilities in customer favorability.
- Motivate employees to achieve corporate objectives.
- Attain increasingly competitive power supply costs.

As a major step toward increased competitiveness, we reduced our workforce by 19% in 1993, largely through early retirement. We respect the decision made by the employees who elected early retirement, and we will miss them. Our streamlined management team includes new members who have added a wealth of energy and ideas. Throughout the Company, we have noted the emergence of skilled and experienced employees who are showing the ability to take responsibility and contribute to our progress.

The following pages provide additional highlights from 1993, an overview of our strategic action plan and specific objectives through the year 2001. The plan is a bold and far-reaching blueprint for progress. Your Board and management are determined to make the plan succeed so that we can meet the single greatest challenge in our history – making the transition from a traditional utility to a more competitive, market-driven business whose profitability rewards all share owners.

Sincerely,

Robert J. Farling

Robert J. Farling
Chairman, President and Chief Executive Officer

March 9, 1994

PERSPECTIVE

SETTING THE STAGE FOR OUR strategic action plan required a period of financial transition involving costly but essential actions that had a major impact on 1993 earnings.

The asset write-offs were among those actions. One write-off involved $598 million, after taxes, of previously deferred charges related to a 1989 rate agreement. The deferred charges were scheduled to be amortized and recovered in the 1994-1998 period. However, current projections show that revenues over that period would not provide for such recovery as scheduled due to economic and competitive pressures. Accordingly, we concluded it was necessary to write off the deferred balance. This action moves us closer to reporting earnings on a cash basis with less reliance on regulatory accounting measures. In addition, because we recognized the charges in 1993, they will not have to be recognized in the 1994-1998 period.

The other write-off was a $425 million, after-tax charge for Unit 2 of the Perry Nuclear Power Plant. Based on our current assessment of power requirements in our region, the partially built unit will not be completed or sold. As a result, the investment must be written off.

Another essential action was the 19% reduction in our workforce. While this will result in substantial savings annually beginning in 1994, the early retirement program that enabled the reduction resulted in a one-time charge against 1993 earnings of $87 million, after taxes.

The write-offs, the workforce reduction cost and $39 million, after taxes, of other year-end charges contributed to a loss of $6.51 per share for 1993. However, our basic business remains stable. Without all of these charges, earnings would have been $1.44 per share, compared with $1.50 per share in 1992.

With these actions behind us, we now can focus on carrying out our strategic action plan. The plan is designed to strengthen us financially and competitively. It includes ambitious objectives and specific goals by which we will monitor and measure our progress. The first priority of the plan is to maximize total return to our share owners, who are deserving beneficiaries of the plan's success.

ONE

FINANCE

A KEY FOCUS OF OUR STRATEGIC ACTION PLAN is the rebuilding of the Company's financial strength. We will measure our success by the improvements we achieve in total annual return to share owners, in terms of both dividends and stock price appreciation, relative to the Standard & Poor's Index of 500 stocks.

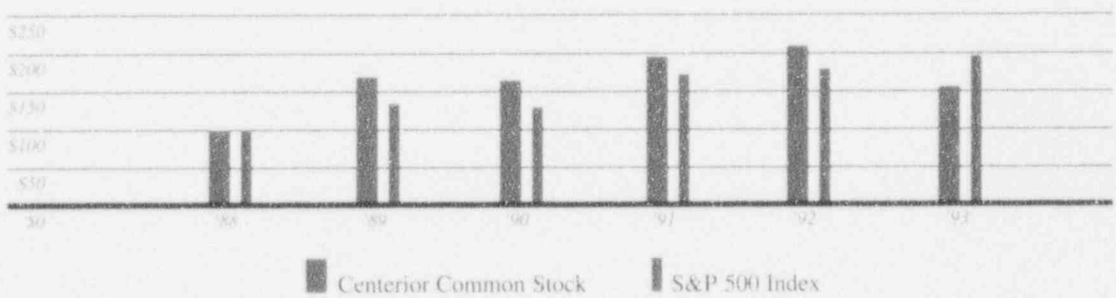
The reduction in the common stock dividend will reduce our cash outflow approximately $120 million annually, which we intend to use to pay off debt more quickly. As a result, we will improve both our capital structure and interest coverage ratios, thus creating opportunities for improved credit ratings on our securities which were lowered by rating agencies in 1993. Improved credit ratings and less outstanding debt will keep down our interest costs. Better credit ratings also will enhance the value of our stock by lowering its risk.

Objective: Provide share owners a total annual return exceeding the Standard & Poor's 500 Index.

Our strategic action plan calls for further reduction in our annual operation and maintenance expenses. This will be challenging because we already reduced those costs by nearly $80 million, or 9%, over the two years prior to 1993. Last year, we experienced some modest increase in those costs, excluding the previously mentioned, one-time charges. For 1994, we anticipate our operation and maintenance expenses will be around $745 million, a $65 million reduction from the adjusted 1993 level. For the rest of the eight-year term of our strategic action plan, we expect to limit any increases in annual operation and maintenance expenses to modest levels below the rate of inflation.

As we work to control costs, capital expenditures will be limited to high priority projects. We have mothballed the last few units operating at our Acme and Lake Shore Plants. This allows us to save some $80 million in capital expenditures while still keeping our reserve margin of generating capacity at an acceptable level. We have no plans to begin construction of new generating facilities until well beyond 2001. At the beginning of 1993, our 10-year capital budget forecast averaged $350 million annually, including spending requirements to comply with federal clean-air legislation. Today, the 10-year budget averages $230 million annually.

FIVE-YEAR COMPARISON OF CUMULATIVE TOTAL RETURN



Five-year total return of $100 invested in Centerior Energy Common Stock at year-end 1988 compared to total return of Standard & Poor's 500 Index for the same period, assuming all dividends were reinvested.

Over the time span of our action plan, we expect that earnings growth will lead to stock price appreciation, thus fulfilling our objective of improved total return to share owners. That earnings growth will come through continued cost control, reductions in our interest charges and, most significantly, from revenue increases, particularly from the aggressive new measures we have developed to increase electricity sales.

From left: Dave Montseau, Vice President–Transmission & Distribution Operations; Fred Lange, Senior Vice President–Fossil & Transmission and Distribution Operations; and Terry Linnert, Vice President–Legal & Governmental Affairs and General Counsel.

TWO REVENUES

TO ACHIEVE REVENUE GROWTH, WE WILL work vigorously to meet more customer needs, compete proactively with other energy providers and encourage economic development in our service area. We also will seek to increase revenues by restructuring our rates to our various customers to suit these changing market conditions.

During the 1970s and 1980s, we cut back on our traditional promotion of kilowatt-hour sales. We did so in response to governmental and societal pressures encouraging energy conservation as a way to defer the added costs and environmental impact of new power plants beyond those already under construction. At the time, work was well under way on Unit 1 of the Perry Nuclear Power Plant and Unit 2 of the Beaver Valley Power Station. Those units are now in service. They give us sufficient generating capacity to accommodate sales growth beyond the year 2001 without the need for additional units.

Objective: Increase annual revenues in an ever-increasing competitive market.

We have resumed promoting electricity sales, but we are doing so in ways consistent with national energy objectives. We are promoting the use of electricity to serve our customers' comfort and convenience, benefit the environment and improve the productivity of businesses while reducing their total energy costs.

Despite the slow-growth economy of our area today, there is considerable potential for increased electricity sales. Unlike other forms of energy, electricity can be applied to many industrial and commercial processes with a flexibility and precision that enhances manufacturing efficiency while decreasing total energy requirements. New electrotechnologies also can reduce emissions from the manufacturing process, thus lowering our customers' costs of complying with pollution control requirements.

To increase our sales and, consequently, our revenues, we are implementing a broad range of new marketing programs which include special communications, direct contact and customer incentives. We especially are targeting specific markets which represent the potential for annual revenue increases in the tens of millions of dollars. For example:

- Electric process heating for use in the automotive, fabricated metals and nonmetals industries. Specific applications include infrared process heating, induction heating and resistance heating.
- Electrical equipment for food service applications.
- Electric baseboard heating, add-on heat pumps, new appliances and portable space heaters in the residential market.
- Use of geothermal heat pumps in new home construction.

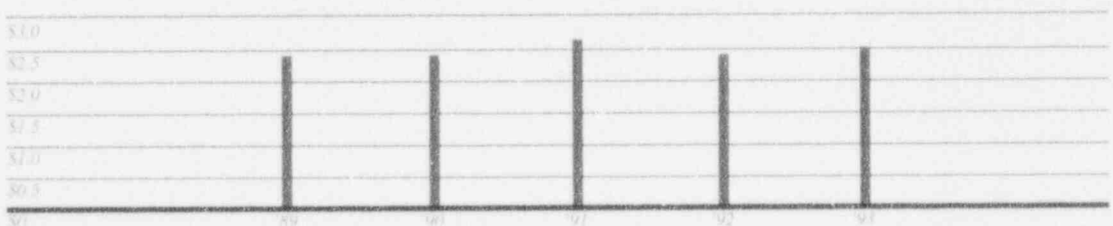
From left: Murray Edelman, Executive Vice President–Operations & Engineering; Jackie Hauserman, Vice President–Customer Support; and Gary Leidich, Vice President–Finance & Administration.

Through a new program called Customer Focus 2000, we have targeted 200 industrial customers, large commercial concerns and residential developers that represent a substantial share of our revenues. We have assigned each of our top management people to serve as a personal liaison with a corporate officer of specific companies. Our objective is to build a rapport with these customers. Then we can better help them in their efforts to remain productive and profitable while, at the same time, discovering new opportunities for kilowatt-hour sales. Customer Focus 2000 was pioneered in the Toledo Edison area in 1993, with good results. We gained greater understanding of the needs of nearly 100 major customers, and 20% of our contacts resulted in sales leads.

In addition to sales promotions, we employ creative new uses for existing assets and resources to add to annual earnings. As one example, we are pursuing partnerships with customers and independent power producers to put underutilized or mothballed generating units to work. As another source of new revenues, we will be marketing our services to local municipalities, water authorities and private entities. In exchange for a fee, we could carry out their meter readings, billing, telephone services, order processing and credit work.

We also are combining revenue-growth strategies with increased promotion of economic development. As one incentive, we return to industrial customers a portion of their electricity payments to be applied to capital investments or other expansion in our service area. In 1993, this plan helped encourage $325 million of capital investments, creating or retaining nearly 3,000

TOTAL REVENUES



Billions

jobs and more than $7 million in annual revenues for us. For example, the Chrysler Corporation received this incentive for starting up production of Dodge Dakota trucks in its Toledo Assembly Plant.

As we work to increase electricity sales, we also are working to retain our customer base. We have negotiated sole-supplier contracts covering 75% of Toledo Edison's industrial sales and 50% of Cleveland Electric's industrial sales. We have achieved major successes in stabilizing municipalization activity. In 1993, we negotiated a new franchise agreement with the City of Toledo and reached an accord with the Cleveland suburb of Brook Park to help prevent creation of municipal electric systems in those communities. Officials in two other cities we serve decided not to proceed at this time with municipalization activities after they examined the risks.

Cleveland Public Power continues its expansion into areas of Cleveland we now serve. CPP's first phase of expansion has converted about 8,000 customers to date. At risk are an estimated 35,000 additional customers over the 1994-1996 period. The number is significant, but these customers represent only about 3% of our total and less than 1.5% of our revenues. The municipal system plans a second phase of expansion to pursue more of our customers starting in 1997. Plans are incomplete and the potential impact on us is not yet known.

To retain our industrial and commercial customers in Cleveland, we are marketing a package of incentives which includes energy-efficiency improvements and reductions in demand charges for increased electricity use. These incentives are offered in return for sole-supplier agreements with us, generally ranging from three to five years. Thus far, approximately 75% of the customers who have made their decisions have elected to stay with us.

CUSTOMER SATISFACTION

AS A HIGH-COST ENERGY SUPPLIER IN A newly competitive industry, we recognize the need to become known for correspondingly high quality service. As part of our strategic action plan, we will continuously measure, analyze and work to increase customer satisfaction with our service.

Good service has many interpretations to our customers. It may be the line mechanic atop a utility pole restoring service after a thunderstorm. It might be the friendly voice answering a customer's telephone call. It may even be the heroic meter reader who crawls into a burning house and carries two children to safety, as occurred in the Cleveland area this past autumn. We are only as good as our customers think we are.

Objective: Raise our customer favorability rating to the top quarter of our industry.

Each year we retain a public opinion research firm to conduct in-depth surveys of a representative sample of our customers. We measure results against past surveys and against 70 other utilities nationwide. Our overall favorability rating in 1993 was 66%. This represents considerable improvement from the low of 45% recorded in 1989. However, we still are three percentage points under the 69% average of all 70 utilities. This puts us in the bottom half. We intend to be in the top quarter before the end of 2001.

To further measure our success in meeting customer expectations, we send follow-up questionnaires to a small sample of customers each month to measure their satisfaction with specific services rendered, such as new electrical installations. Another valuable source of feedback is provided by our three Consumer Advisory Panels who assist us in developing customer communications and new service options. We are developing other means to guide our efforts to enhance customer satisfaction.

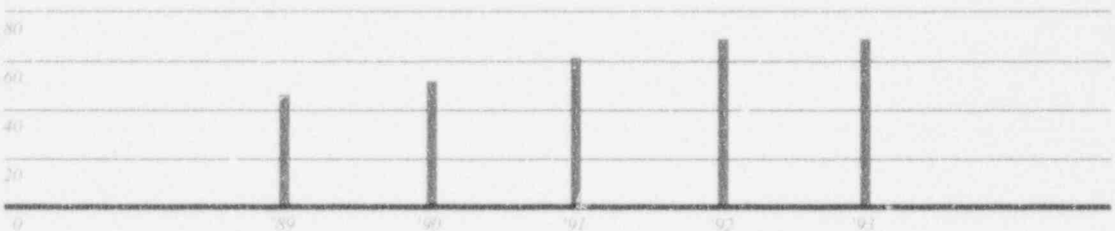
Our action plan includes specific goals to improve basic services affecting customer satisfaction. We intend to reduce customer call-waiting time and the frequency of power interruptions. We also will accelerate service restoration, the replacement of burned-out street lamps and new residential and commercial installations. In many of these categories, our response time already is above average for the electric utility industry. Our goal is to achieve significant improvement in 1994 and to rank in the top 10% of the industry in all categories by 2001.

Our customer responsiveness was severely tested in 1993. A devastating thunderstorm on July 28 disrupted electric service to some 360,000 Cleveland Electric customers, about half of that company's total number of customers. Our service crews, operations personnel and telephone representatives reacted superbly. Service was restored to 97% of the affected customers within four days. However, our greatest disappointment in this emergency was our inability to provide customers with accurate estimates as to when their power might be restored. We are implementing procedural improvements to deal with this.

Among other service improvements in 1993, we activated our new Horizon Substation to improve reliability in downtown Cleveland and to serve the new Gateway sports complex. We also set up a new communications system allowing customers with touch-tone phones to automatically access their account information and to report power outages. In addition, we established a national computer link so that most new service applications can be processed by phone rather than requiring an in-person visit by the customer. In 1994, we will test automated meter reading on a pilot basis for possible system-wide phase-in over a five-year period. This would enhance our billing accuracy while reducing our meter-reading costs.

We continue to provide the energy-efficiency programs that give customers more control over their energy usage and costs. These programs include energy-efficiency rate incentives, conservation initiatives, load controls, energy information and other measures to benefit customers. In some instances, these programs might mean a modest reduction in our revenues. Nevertheless, they are essential to good customer service and enhanced customer satisfaction. Equally important, they help our commercial and industrial customers reduce costs and retain their competitiveness in national and global markets. Ultimately, this improves our own sales and revenue prospects for the long-term benefit of share owners.

CUSTOMER FAVORABILITY RATING



Percent

EMPLOYEES

EVEN IN THIS ERA OF HIGH TECHNOLOGY, employees remain our single most important resource in serving customers and maximizing total return to share owners. We recognize that the primary criteria for success is not the number of employees but rather their skills, personal development and commitment. Management's task is to provide the training, leadership and cultural environment to support employee efforts.

As a result of the workforce reduction in 1993 and earlier downsizings, we have cut our total number of employees from 9,062 at year-end 1989 to 6,748 at year-end 1993. In that time, upper management was reduced from 85 to 50. Responsibilities have been broadened and some executives are being challenged with entirely new responsibilities. Our reduced numbers are consistent with other utilities which also have been downsizing their staffs to control costs.

Objective: Amplify employee commitment to corporate objectives.

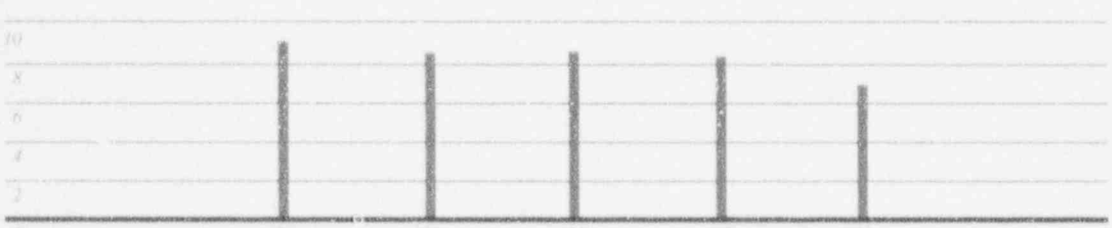
Meanwhile, we are stressing accountability. As we have streamlined management, so have we reduced direct supervision. We are empowering employees to handle greater responsibilities and make more decisions. We also are developing training programs and incentives to encourage every employee to be part of our sales team.

To prepare them for their expanded roles, we are establishing cross-functional teams of employees to identify and address key corporate issues. No one knows the workings of our business better than our employees; they are in the best position to propose solutions to problems and new ways to increase efficiency and reduce costs. Management gives their views full attention.

Consistent with our expectations of employees, we are developing a total compensation strategy that provides cost-effective and appropriate rewards. The key to this strategy is incentive pay to reward employees based on the achievement of corporate objectives.

Today's workforce is more diverse than any we have had in the past. Our employees are much more challenged than their predecessors. The past few years have been characterized by rapid change, uncertainty and increasing demands. Nevertheless, our employees have maintained their dedication to the job, concern for customers and loyalty to the Company and its mission. With their continuing commitment, we are confident we can successfully achieve the objectives of our strategic action plan.

EMPLOYEES (Year End)



Thousands

POWER SUPPLY

VARIABLE POWER SUPPLY COSTS INCLUDE fuel expenses and operation and maintenance expenses for our generating units, as opposed to the fixed costs resulting from construction. Our strategic action plan calls upon us to reduce our variable power supply costs on a three-year rolling average from the 1993 level of 2.5 cents per kilowatt-hour to 2.2 cents by the end of 1998. We then will limit subsequent increases so that they do not exceed 2.3 cents per kilowatt-hour at year-end 2001.

By reducing our production costs per kilowatt-hour, we become more competitive in our own service area and in the wholesale energy market. This will become increasingly important as deregulation provides new opportunities for independent power producers and encourages more wholesale wheeling of power and, possibly, retail wheeling beyond traditional service area boundaries.

Objective: Reduce variable power supply costs to a more competitive level.

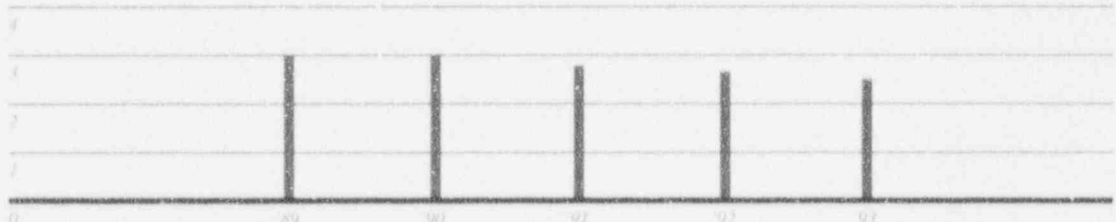
We will achieve our cost-reduction goal by improving plant performance and reducing outage times. These will be achieved through efficiency-enhancement projects and improved maintenance and scheduling. We also will use technological upgrades and experimentation when appropriate:

- In 1993, for example, we completely computerized the control room of a 132-megawatt unit at our Eastlake Plant, which greatly improved the unit's operations.
- This year, we are experimenting with a process called oxygenated boiler-water treatment to protect against boiler tube corrosion, thus reducing maintenance needs.

The cost-reduction goal will also be achieved by lowering fuel costs, which are a little more than half of our variable power supply costs. We expect the unit cost of our nuclear fuel to decline 33% by the end of 2001. We have used most of our inventory of higher-priced uranium fuel and can now take advantage of the lower-cost fuel purchased more recently. Our coal costs per ton are expected to come down 15% by the end of 1995 because of the lower-cost purchases we are able to make on the spot market.

Typically, about 40% of our generating output comes from our three nuclear units. The longest-running of the three is the Davis-Besse Nuclear Power Station, which continued its fine level of performance in 1993. Davis-Besse received its highest marks ever from the Nuclear Regulatory Commission in its most recent Systematic Assessment of Licensee Performance. Also continuing

PRODUCTION COSTS



Cents Per Kilowatt-Hour (Three-Year Rolling Average) above-average operations is Beaver Valley Unit 2 in which we share ownership. At year-end 1993, the three-year availability average of each unit was 87%. Those marks are well above the industry average of 78% for pressurized water reactors.

From left: Bob Stratman, Vice President–Nuclear–Perry and Don Shelton, Senior Vice President–Nuclear

The 1993 performance of our third nuclear generating facility, Perry Unit 1, fell below expectations, bringing down Perry's three-year availability average to 67%. This falls short of the 72% industry average for boiling water reactors. Perry experienced a series of maintenance problems last year, sharply increasing its downtime.

We are working to turn the plant around. The Perry management team is now headed by some of the key people who saw Davis-Besse through a $200 million improvement program in the mid-1980s with outstanding results. We have embarked on a two-year, in-depth course of action at Perry which includes more aggressive maintenance, improved quality assessment and heightened management involvement at all levels. Our cost is estimated to be $33 million. The Nuclear Regulatory Commission has concurred that successful implementation of this course of action will achieve our objectives for Perry.

Our environmental engineering efforts over the years have placed us ahead of many other utilities in reducing sulfur dioxide emissions from fossil-fueled units as required by the Clean Air Act. More than two-thirds of our generation is already in compliance with existing law or is not affected by the legislation. We will bring the remaining third into compliance by the time required primarily by switching to lower-sulfur fuels. The necessary expenditures will have no material effect on our electric rates.

Many other coal-reliant utilities in our region face much higher environmental protection costs. As a result, their electric rates over the next several years will increase by a greater margin than ours. This will bring us closer to rate parity, making us more competitive in our region.

We are about to begin a two-year, $30 million upgrade of our System Operations Center located near Cleveland. The Center coordinates the generation and transmission of bulk power throughout our system. This upgrade will ensure the availability of power for our own customers while making it easier for us to market our electricity in other regions.

Power production is the heart of our business. As we continue improving our operating efficiencies and reducing costs, we will be that much further along in making the successful transition to being a more market-driven business and in improving total return to share owners.

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Centerior Energy Corporation is responsible for the consolidated financial statements in this Annual Report. The statements were prepared in accordance with generally accepted accounting principles. Under these principles, some of the recorded amounts are based on estimates which are, in turn, based on an analysis of the best information available.

We maintain a system of internal accounting controls designed to assure that the financial records are substantially complete and accurate. The controls also are designed to help protect the assets and their related records. We structure our control procedures such that their costs do not exceed their benefits.

Our internal audit program monitors the internal accounting controls. This program gives us the opportunity to assess the adequacy and effectiveness of existing controls and to identify and institute changes where needed. In addition, an examination of our financial statements is conducted by Arthur Andersen & Co., independent public accountants, whose report appears below.

Our Board of Directors is responsible for determining whether management and the independent public accountants are carrying out their responsibilities. The Board is also responsible for making changes in management or independent public accountants if needed.

The Board has appointed an Audit Committee, comprised entirely of outside directors, which met two times in 1993. The Committee recommends annually to the Board the firm of independent public accountants to be retained for the ensuing year and reviews the audit approach used by the accountants plus the results of their audits. It also oversees the adequacy and effectiveness of our internal accounting controls and ensures that our accounting system produces financial statements which present fairly our financial position.

Gary R. Leidich

GARY R. LEIDICH
Vice President and
Chief Financial Officer

Paul G. Busby

PAUL G. BUSBY
Controller and
Chief Accounting Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

ARTHUR ANDERSEN &CO.

To the Share Owners and
Board of Directors of
Centerior Energy Corporation:

We have audited the accompanying consolidated balance sheet and consolidated statement of preferred stock of Centerior Energy Corporation (an Ohio corporation) and subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1993. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Centerior Energy Corporation and subsidiaries as of December 31, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

As discussed further in Notes 1 and 9, changes were made in the methods of accounting for nuclear plant depreciation in 1991 and for postretirement benefits other than pensions in 1993.

Arthur Andersen & Co

Cleveland, Ohio
February 14, 1994

MANAGEMENT'S FINANCIAL ANALYSIS

Results of Operations

1993 vs. 1992

Factors contributing to the 1.5% increase in 1993 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
Sales Volume and Mix	$ 65
Base Rates and Miscellaneous	(18)
Fuel Cost Recovery Revenues	(11)
Total	$ 36

The net revenue increase resulted primarily from the different weather conditions and the changes in the composition of the sales mix among customer categories. Weather accounted for approximately $53 million of the higher 1993 revenues. Hot summer weather in 1993 boosted residential, commercial and wholesale kilowatt-hour sales. In contrast, the 1992 summer was the coolest in 56 years in Northern Ohio. Residential and commercial sales also increased as a result of colder late-winter temperatures in 1993 which increased electric heating-related demand. As a result, total sales increased 3.1% in 1993. Residential and commercial sales increased 4.6% and 3.1%, respectively. Industrial sales increased 1.2%. Increased sales to large automotive manufacturers, petroleum refiners and the broad-based, smaller industrial group were partially offset by lower sales to large steel industry customers. Other sales increased 5.9% because of increased sales to wholesale customers. Base rates and miscellaneous revenues decreased in 1993 primarily from lower revenues under contracts having reduced rates with certain large customers and a declining rate structure tied to usage. The contracts have been negotiated to meet competition and encourage economic growth. The net decrease in 1993 fuel cost recovery revenues resulted from changes in the fuel cost factors. The weighted average of these factors increased slightly for The Toledo Edison Company (Toledo Edison) but decreased 5% for The Cleveland Electric Illuminating Company (Cleveland Electric).

Operating expenses increased 13.7% in 1993. The increase in total operation and maintenance expenses resulted from the $218 million of net benefit expenses related to an early retirement program, called the Voluntary Transition Program (VTP), other charges totaling $54 million and an increase in other operation and maintenance expenses. Other charges recorded at year-end 1993 related to a performance improvement plan for Perry Nuclear Power Plant Unit 1 (Perry Unit 1), postemployment benefits and other expense accruals. The increase in other operation and maintenance expenses resulted from higher environmental expenses, power restoration and repair expenses following a July 1993 storm in the Cleveland area, and an increase in other postretirement benefit expenses. See Note 9 for information on retirement and postemployment benefits. Deferred operating expenses decreased because of the write-off of the phase-in deferred operating expenses in 1993 as discussed in Note 7. Federal income taxes decreased as a result of lower pretax operating income.

As discussed in Note 4(b), $583 million of our Perry Nuclear Power Plant Unit 2 (Perry Unit 2) investment was written off in 1993. Credits for carrying charges recorded in nonoperating income decreased because of the write-off of the phase-in deferred carrying charges in 1993 as discussed in Note 7. The federal income tax credit for nonoperating income in 1993 resulted from the write-offs.

1992 vs. 1991

Factors contributing to the 4.8% decrease in 1992 operating revenues are as follows:

Decrease in Operating Revenues	Millions of Dollars
Sales Volume and Mix	$ 79
Base Rates and Miscellaneous	32
Fuel Cost Recovery Revenues	11
Total	$122

The revenue decreases resulted primarily from the different weather conditions and the changes in the composition of the sales mix among customer categories. Weather accounted for approximately $77 million of the lower 1992 revenues. Winter and spring in 1992 were milder than in 1991. In addition, the cooler summer in 1992 contrasted with the summer of 1991 which was much hotter than normal. As a result, total kilowatt-hour sales decreased 1.1% in 1992. Residential and commercial sales decreased 4.5% and 1.3%, respectively, as moderate temperatures in 1992 reduced electric heating and cooling demands. Industrial sales were virtually the same as in 1991 as sales increases to steel producers and auto manufacturers of 10.9% and 2.7%, respectively, offset a decline in sales to other industrial customers. Other sales increased 2.3% because of increased sales to wholesale customers. Operating revenues in 1991 included the recognition by Toledo Edison of $24 million of deferred revenues over the period of a refund to customers under a provision of its January 1989 rate order. No such revenues were reflected in 1992 as the refund period ended in December 1991. The decrease in 1992 fuel cost recovery revenues resulted from the good performance of our generating units, which in turn decreased our fuel cost factors. The weighted averages of these factors decreased approximately 3% for Cleveland Electric and Toledo Edison (Operating Companies).

Operating expenses decreased 4% in 1992. Lower fuel and purchased power expense resulted from less amortization of previously deferred fuel costs than the amount amortized in 1991 and lower generation requirements stemming from less electric sales. A reduction of $17 million in other operation and maintenance expenses resulted primarily from cost-cutting measures. Federal income taxes decreased because of the amortization of certain tax benefits under the Rate Stabilization Program discussed in Note 7 and the effects of adopting the new accounting standard for income taxes (SFAS 109) in 1992. These decreases were partially offset by higher depreciation and amortization, caused primarily by the adoption of SFAS 109, and by higher taxes, other than federal income taxes, caused by increased Ohio property and gross receipts taxes. Deferred operating expenses increased as a result of the deferrals under the Rate Stabilization Program.

The federal income tax provision for nonoperating income decreased because of lower carrying charge credits and a greater tax allocation of interest charges to nonoperating activities. Credits for carrying charges recorded in nonoperating income decreased primarily because of lower phase-in carrying charge credits. Interest charges decreased as a result of debt refinancings at lower interest rates and lower short-term borrowing requirements.

Outlook

Recent Actions

In January 1994, we announced a comprehensive strategic action plan to strengthen our financial and competitive position. The plan established specific objectives and was designed to guide us through the year 2001. While the plan has a long-term focus, it also required us to take some very difficult, but necessary, financial actions at that time. We reduced the quarterly common stock dividend from \$.40 per share to \$.20 per share effective with the dividend payable February 15, 1994. This action was taken because projected financial results did not support continuation of the dividend at its former rate. We also wrote off our investment in Perry Unit 2 and certain deferred charges related to a January 1989 rate agreement (phase-in deferrals). The aggregate after-tax effect of these write-offs was \$1.023 billion which resulted in a net loss in 1993 and a retained earnings deficit. The write-offs are discussed in Notes 4(b) and 7. We also recognized other one-time charges totaling \$39 million after taxes related to a performance improvement plan for Perry Unit 1, postemployment benefits and other expense accruals.

Also contributing to the net loss in 1993 was a charge of \$87 million after taxes representing a portion of the VTP costs. We will realize approximately \$50 million of savings in annual payroll and benefit costs beginning in 1994 as a result of the VTP.

Strategic Plan

The objectives of our strategic plan are to maximize share owner return from corporate assets and resources, achieve profitable revenue growth, become an industry leader in customer satisfaction, build a winning team and attain increasingly competitive power supply costs. To achieve these objectives, we will continue controlling our operation and maintenance expenses and capital expenditures, reduce our outstanding debt, increase revenues by finding new uses for existing assets and resources, implement a broad range of new marketing programs, increase revenues by restructuring rates for various customers where appropriate, improve the operating performance of our plants and take other appropriate actions.

Common Stock Dividends

The indicated quarterly common stock dividend is \$.20 per share. We believe that the new level is sustainable barring unforeseen circumstances and that the new strategic plan will provide the opportunity to grow the dividend as the objectives are achieved. Nevertheless, future dividend action by our Board of Directors will continue to be decided on a quarter-to-quarter basis after the evaluation of financial results, potential earning capacity and cash flow.

The lower dividend reduces our cash outflow by about \$120 million annually, which we intend to use to repay debt more quickly than would otherwise be the case. This will help improve our capitalization structure and interest coverage ratios, both of which are key measures considered by securities rating agencies in determining credit ratings. Improved credit ratings and less outstanding debt, in turn, will lower our interest costs.

Competition

Our electric rates are among the highest in our region because we are recovering the substantial investment in our nuclear construction program. Accordingly, some of our customers continue to seek less costly alternatives, including switching to or working to create a municipal electric system. There are a number of rural and municipal systems in our service area. In addition, we face threats of other municipalities in our service area establishing new systems and the expansion of an existing system. We have entered into agreements with some of the communities which considered establishing systems. Accordingly, they will not proceed with such development at this time in return for rate concessions and/or economic development funds. Others have determined that developing a system was not feasible. Cleveland Public Power continues to expand its operations into areas we have served exclusively. We have been successful in retaining most of the large industrial and commercial customers in those areas by providing economic incentive packages in exchange for sole-supplier contracts. We also have similar contracts with customers in other areas. Most of these contracts have remaining terms of one to five years. We will continue to address municipal system threats through aggressive marketing programs and emphasizing to our customers the value of our service and the risks of a municipal system.

The Energy Policy Act of 1992 (Energy Act) will provide additional competition in the electric utility industry by requiring utilities to wheel to municipal systems in their service areas electricity from other utilities. This provision of the Energy Act should not significantly increase the competitive threat to us since the operating licenses for our nuclear units have required us to wheel to municipal systems in our service area since 1977. The Energy Act also created a class of exempt wholesale generators which may increase competition in the wholesale power market. A further risk is the possibility that the government could mandate that utilities deliver power from another utility or generation source to their retail customers.

Rate Matters

Our Rate Stabilization Program remains in effect. Under this program, we agreed to freeze base rates until 1996 and limit rate increases through 1998. In exchange, we are permitted to defer through 1995 and subsequently recover certain costs not currently recovered in rates and to accelerate the amortization of certain benefits. The amortization and recovery of the deferrals will begin with future rate recognition and will continue over the average life of the related assets, or approximately 30 years. The continued use of these regulatory accounting measures will be dependent upon our continuing assessment and conclusion that there will be probable recovery of such deferrals in future rates.

Our analysis leading to the year-end 1993 financial actions and strategic plan also included an evaluation of our regulatory accounting measures. We decided that, once the deferral of expenses and acceleration of benefits under our Rate Stabilization Program are completed in 1995, we should no longer plan to use regulatory accounting measures to the extent we have in the past.

Nuclear Operations

Our three nuclear units may be impacted by activities or events beyond our control. Operating nuclear generating units have experienced unplanned outages or extensions of scheduled outages because of equipment problems or new regulatory requirements. A major accident at a nuclear facility anywhere in the world could cause the Nuclear Regulatory Commission (NRC) to limit or prohibit the operation or licensing of any nuclear unit. If one of our nuclear units is taken out of service for an extended period of time for any reason, including an accident at such unit or any other nuclear facility, we cannot predict whether regulatory authorities would impose unfavorable rate treatment. Such treatment could include taking our affected unit out of rate base or disallowing certain construction or maintenance costs. An extended outage of one of our nuclear units coupled with unfavorable rate treatment could have a material adverse effect on our financial condition and results of operations.

We externally fund the estimated costs for the future decommissioning of our nuclear units. In 1993, we increased our decommissioning expense accruals for revisions in our cost estimates. We expect the increases associated with the new estimates will be recoverable in future rates. See Note 1(e).

Hazardous Waste Disposal Sites

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended (Superfund) established programs addressing the cleanup of hazardous waste disposal sites, emergency preparedness and other issues. The Operating Companies have been named as "potentially responsible parties" (PRPs) for three sites listed on the Superfund National Priorities List (Superfund List) and are aware of their potential involvement in the cleanup of several other sites not on such list. The allegations that the Operating Companies disposed of hazardous waste at these sites and the amounts involved are often unsubstantiated and subject to dispute. Superfund provides that all PRPs to a particular site can be held liable on a joint and several basis. Consequently, if the Operating Companies were held liable for 100% of the cleanup costs of all of the sites referred to above, the cost could be as high as $400 million. However, we believe that the actual cleanup costs will be substantially lower than $400 million, that the Operating Companies' share of any cleanup costs will be substantially less than 100% and that most of the other PRPs are financially able to contribute their share. The Operating Companies have accrued a liability totaling $19 million at December 31, 1993 based on estimates of the costs of cleanup and their proportionate responsibility for such costs. We believe that the ultimate outcome of these matters will not have a material adverse effect on our financial condition or results of operations.

1993 Tax Act

The Revenue Reconciliation Act of 1993 (1993 Tax Act), which was enacted in August 1993, provided for a 35% income tax rate in 1993. The 1993 Tax Act did not materially impact the results of operations for 1993, but did affect certain Balance Sheet accounts as discussed in Note 8. The 1993 Tax Act is not expected to materially impact future results of operations or cash flow.

Inflation

Although the rate of inflation has eased in recent years, we are still affected by even modest inflation which causes increases in the unit cost of labor, materials and services.

Capital Resources and Liquidity

1991-1993 Cash Requirements

We need cash for normal corporate operations, the mandatory retirement of securities and an ongoing program of constructing new facilities and modifying existing facilities. The construction program is needed to meet anticipated demand for electric service, comply with governmental regulations and protect the environment. Over the three-year period of 1991-1993, these construction and mandatory retirement needs totaled approximately $1.4 billion. In addition, we exercised various options to redeem and purchase approximately $900 million of our securities.

We raised $2.2 billion through security issues and term bank loans during the 1991-1993 period as shown in the Cash Flows statement. During the three-year period, the Operating Companies also utilized their short-term borrowing arrangements to help meet their cash needs.

Although the write-offs of Perry Unit 2 and the phase-in deferrals in 1993 negatively affected our earnings, they did not adversely affect our current cash flow.

1994 and Beyond Cash Requirements

Estimated cash requirements for 1994-1998 for Cleveland Electric and Toledo Edison, respectively, are $791 million and $249 million for their construction programs and $715 million and $324 million for the mandatory redemption of debt and preferred stock. Cleveland Electric and Toledo Edison expect to finance internally all of their 1994 cash requirements of approximately $239 million and $109 million, respectively. About 15-20% of the Operating Companies' 1995-1998 requirements are expected to be financed externally. If economical, additional securities may be redeemed under optional redemption provisions.

Our capital requirements are dependent upon our implementation strategy to achieve compliance with the Clean Air Act Amendments of 1990 (Clean Air Act). Cash expenditures for our plan are estimated to be approximately $128 million over the 1994-1998 period. See Note 4(a).

Liquidity

Additional first mortgage bonds may be issued by the Operating Companies under their respective mortgages on the basis of property additions, cash or refundable first mortgage bonds. Under their respective mortgages, each Operating Company may issue first mortgage bonds on the basis of property additions and, under certain circumstances, refundable bonds only if the applicable interest coverage test is met. At December 31, 1993, Cleveland Electric and Toledo Edison would have been permitted to issue approximately $78 million and $323 million of additional first mortgage bonds, respectively. After the fourth quarter of 1994, Cleveland Electric's ability to issue first mortgage bonds is expected to increase substantially when its interest coverage ratio will no longer be affected by the write-offs recorded at December 31, 1993.

As discussed in Note 11(e), certain unsecured debt agreements contain covenants relating to capitalization, fixed charge coverage ratios and secured financings. The write-offs recorded at December 31, 1993 caused Centerior Energy Corporation (Centerior Energy) and the Operating Companies to violate certain of those covenants. The affected creditors have waived those violations in exchange for our commitment to provide them with a second mortgage security interest on our property and other considerations. We expect to complete this process in the second quarter of 1994. We will provide the same security interest to certain other creditors because their agreements require equal treatment. We expect to provide second mortgage collateral for $219 million of unsecured debt, $228 million of bank letters of credit and a $205 million revolving credit facility. For the next five years, the Operating Companies do not expect to raise funds through the sale of debt junior to first mortgage bonds. However, if necessary or desirable, the Operating Companies believe that they could raise funds through the sale of unsecured debt or debt secured by the second mortgage referred to above. The Operating Companies also are able to raise funds through the sale of preference stock and, in the case of Cleveland Electric, preferred stock. Toledo Edison will be unable to issue preferred stock until it can meet the interest and preferred dividend coverage test in its articles of incorporation. Centerior Energy will continue to raise funds through the sale of common stock.

The Operating Companies currently cannot sell commercial paper because of their low commercial paper ratings by Standard & Poor's Corporation (S&P) and Moody's Investors Service, Inc. (Moody's) of "B" and "Not Prime", respectively. We have a $205 million revolving credit facility which will run through mid-1996. However, we currently cannot draw on this facility because the write-offs taken at year-end 1993 caused us to fail to meet certain capitalization and fixed charge coverage covenants. We expect to have this facility available to us again after it is amended in the second quarter of 1994 to provide the participating creditors with a second mortgage security interest.

These financing resources are expected to be sufficient for the Operating Companies' needs over the next several years. The availability and cost of capital to meet our external financing needs, however, also depend upon such factors as financial market conditions and our credit ratings. Current credit ratings for both Operating Companies are as follows:

	S&P	Moody's
First mortgage bonds	BB	Ba2
Unsecured notes	B+	Ba3
Preferred stock	B	b1

These ratings reflect a downgrade in December 1993. In addition, S&P has issued a negative outlook for the Operating Companies.

INCOME STATEMENT

Centerior Energy Corporation and Subsidiaries

	For the years ended December 31,		
	1993	1992	1991
	(millions of dollars, except per share amounts)		
Operating Revenues	$2,474	$2,438	$2,560
Operating Expenses			
Fuel and purchased power	474	473	500
Other operation and maintenance	811	784	801
Early retirement program expenses and other	272	—	—
Total operation and maintenance	1,557	1,257	1,301
Depreciation and amortization	258	256	243
Taxes, other than federal income taxes	312	318	305
Deferred operating expenses, net	23	(52)	(6)
Federal income taxes	11	122	138
	2,161	1,901	1,981
Operating Income	313	537	579
Nonoperating Income (Loss)			
Allowance for equity funds used during construction	5	2	9
Other income and deductions, net	(6)	9	6
Write-off of Perry Unit 2	(583)	—	—
Deferred carrying charges, net	(649)	100	110
Federal income taxes — credit (expense)	398	(7)	(30)
	(835)	104	95
Income (Loss) Before Interest Charges and Preferred Dividends	(522)	641	674
Interest Charges and Preferred Dividends			
Debt interest	359	365	381
Allowance for borrowed funds used during construction	(5)	(1)	(5)
Preferred dividend requirements of subsidiaries	67	65	61
	421	429	437
Net Income (Loss)	$ (943)	$ 212	$ 237
Average Number of Common Shares Outstanding (millions)	144.9	141.7	139.1
Earnings (Loss) Per Common Share	$(6.51)	$ 1.50	$ 1.71
Dividends Declared Per Common Share	$ 1.60	$ 1.60	$ 1.60

RETAINED EARNINGS

	For the years ended December 31,		
	1993	1992	1991
	(millions of dollars)		
Retained Earnings at Beginning of Year	$ 652	$ 669	$ 655
Additions			
Net income (loss)	(943)	212	237
Deductions			
Common stock dividends	(231)	(226)	(222)
Other, primarily preferred stock redemption expenses of subsidiaries	(1)	(3)	(1)
Net Increase (Decrease)	(1,175)	(17)	14
Retained Earnings (Deficit) at End of Year	$ (523)	$ 652	$ 669

The accompanying notes are an integral part of these statements.

BALANCE SHEET

	December 31, 1993	December 31, 1992
	(millions of dollars)	
ASSETS		
Property, Plant and Equipment		
Utility plant in service	$ 9,571	$ 9,449
Less: accumulated depreciation and amortization	2,677	2,488
	6,894	6,961
Construction work in progress	181	167
Perry Unit 2	—	614
	7,075	7,742
Nuclear fuel, net of amortization	344	385
Other property, less accumulated depreciation	41	39
	7,460	8,166
Current Assets		
Cash and temporary cash investments	225	93
Amounts due from customers and others, net	221	222
Unbilled revenues	124	114
Materials and supplies, at average cost	136	129
Fossil fuel inventory, at average cost	32	65
Taxes applicable to succeeding years	250	247
Other	5	7
	993	877
Deferred Charges and Other Assets		
Amounts due from customers for future federal income taxes	968	975
Unamortized loss from Beaver Valley Unit 2 sale	105	110
Unamortized loss on reacquired debt	92	101
Carrying charges and operating expenses	862	1,533
Nuclear plant decommissioning trusts	56	42
Other	174	267
	2,257	3,028
Total Assets	$10,710	$12,071

The accompanying notes are an integral part of this statement.

	December 31, 1993	December 31, 1992
	(millions of dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shares, without par value (stated value of $345 million and $274 million for 1993 and 1992, respectively): 180 million authorized; 147 million (excluding 2.7 million shares in Treasury) and 142.9 million (excluding 2.7 million shares in Treasury) outstanding in 1993 and 1992, respectively	$ 2,308	$ 2,237
Retained earnings (deficit)	(523)	652
Common stock equity	1,785	2,889
Preferred stock		
With mandatory redemption provisions	313	364
Without mandatory redemption provisions	451	354
Long-term debt	4,019	3,694
	6,568	7,301
Other Noncurrent Liabilities		
Nuclear fuel lease obligations	254	303
Other	195	119
	449	422
Current Liabilities		
Current portion of long-term debt and preferred stock	127	368
Current portion of nuclear fuel lease obligations	111	118
Notes payable to banks and others	—	50
Accounts payable	188	143
Accrued taxes	378	368
Accrued interest	87	84
Other	75	59
	966	1,190
Deferred Credits		
Unamortized investment tax credits	329	353
Accumulated deferred federal income taxes	1,579	2,035
Unamortized gain from Bruce Mansfield Plant sale	551	578
Accumulated deferred rents for Bruce Mansfield Plant and Beaver Valley Unit 2	128	116
Other	140	76
	2,727	3,158
Total Capitalization and Liabilities	$10,710	$12,071

	For the years ended December 31,		
	1993	1992	1991
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income (Loss)	$ (943)	$ 212	$ 237
Adjustments to Reconcile Net Income (Loss) to Cash from Operating Activities:			
Depreciation and amortization	258	256	243
Deferred federal income taxes	(452)	95	85
Investment tax credits, net	—	(14)	43
Deferred and unbilled revenues	(10)	(6)	(51)
Deferred fuel	5	1	18
Deferred carrying charges, net	649	(100)	(110)
Leased nuclear fuel amortization	86	126	123
Deferred operating expenses, net	23	(52)	(6)
Allowance for equity funds used during construction	(5)	(2)	(9)
Noncash early retirement program expenses, net	208	—	—
Write-off of Perry Unit 2	583	—	—
Changes in amounts due from customers and others, net	1	7	14
Changes in inventories	26	(10)	(22)
Changes in accounts payable	45	(5)	(49)
Changes in working capital affecting operations	25	8	19
Other noncash items	18	3	1
Total Adjustments	1,460	307	299
Net Cash from Operating Activities	517	519	536
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	(50)	50	(110)
Debt issues:			
First mortgage bonds	300	600	—
Secured medium-term notes	128	138	285
Term bank loans and other long-term debt	40	135	108
Preferred stock issues	100	74	125
Common stock issues	71	53	32
Reacquired common stock	1	(3)	—
Maturities, redemptions and sinking funds	(434)	(1,013)	(312)
Nuclear fuel lease obligations	(106)	(117)	(116)
Common stock dividends paid	(231)	(226)	(222)
Premiums, discounts and expenses	(13)	(14)	(7)
Net Cash from Financing Activities	(194)	(323)	(217)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(209)	(200)	(189)
Interest capitalized as allowance for borrowed funds used during construction	(5)	(1)	(5)
Sale and leaseback restructuring fees	—	(43)	—
Other cash received (applied)	23	(36)	(1)
Net Cash from Investing Activities	(191)	(280)	(195)
Net Change in Cash and Temporary Cash Investments	132	(84)	124
Cash and Temporary Cash Investments at Beginning of Year	93	177	53
Cash and Temporary Cash Investments at End of Year	$ 225	$ 93	$ 177

(1) Interest paid (net of amounts capitalized) was $295 million, $299 million and $339 million in 1993, 1992 and 1991, respectively. Income taxes paid were $50 million, $32 million and $57 million in 1993, 1992 and 1991, respectively.

(2) Increases in Nuclear Fuel and Nuclear Fuel Lease Obligations in the Balance Sheet resulting from the noncash capitalizations under nuclear fuel agreements are excluded from this statement.

The accompanying notes are an integral part of this statement.

STATEMENT OF PREFERRED STOCK

Centerior Energy Corporation and Subsidiaries

	1993 Shares Outstanding	Current Call Price Per Share	December 31, 1993	December 31, 1992
			(millions of dollars)	
CLEVELAND ELECTRIC				
Without par value, 4,000,000 preferred shares authorized				
Subject to mandatory redemption:				
\$ 7.35 Series C	150,000	\$ 101.00	\$ 15	\$ 16
88.00 Series E	21,000	1,022.96	21	24
Adjustable Series M	200,000	100.00	20	30
9.125 Series N	600,000	103.04	59	74
91.50 Series Q	75,000	—	75	75
88.00 Series R	50,000	—	50	50
90.00 Series S	75,000	—	74	74
			314	343
Less: Current maturities			29	29
			285	314
Not subject to mandatory redemption:				
\$ 7.40 Series A	500,000	101.00	50	50
7.56 Series B	450,000	102.26	45	45
Adjustable Series L	500,000	103.00	49	49
Remarketed Series P	—	—	—	9
42.40 Series T	200,000	—	97	—
			241	153
Less: Current maturities			—	9
			241	144
TOLEDO EDISON				
\$100 par value, 3,000,000 preferred shares authorized and \$25 par value, 12,000,000 preferred shares authorized				
Subject to mandatory redemption:				
\$100 par \$9.375	100,150	102.47	10	12
25 par 2.81	1,200,000	25.94	30	50
			40	62
Less: Current maturities			12	12
			28	50
Not subject to mandatory redemption:				
\$100 par \$ 4.25	160,000	104.625	16	16
4.56	50,000	101.00	5	5
4.25	100,000	102.00	10	10
8.32	100,000	102.46	10	10
7.76	150,000	102.437	15	15
7.80	150,000	101.65	15	15
10.00	190,000	101.00	19	19
25 par 2.21	1,000,000	25.25	25	25
2.365	1,400,000	27.75	35	35
Series A Adjustable	1,200,000	25.75	30	30
Series B Adjustable	1,200,000	25.75	30	30
			210	210
CENTERIOR ENERGY				
Without par value, 5,000,000 preferred shares authorized, none outstanding			—	—
Total Preferred Stock, with Mandatory Redemption Provisions			\$313	\$364
Total Preferred Stock, without Mandatory Redemption Provisions			\$451	\$354

The accompanying notes are an integral part of this statement.

NOTES TO THE FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

(a) General

Centerior Energy is a holding company with two electric utility subsidiaries, Cleveland Electric and Toledo Edison. The consolidated financial statements also include the accounts of Centerior Energy's other wholly owned subsidiary, Centerior Service Company (Service Company), and Cleveland Electric's wholly owned subsidiaries. The Service Company provides management, financial, administrative, engineering, legal and other services at cost to Centerior Energy and the Operating Companies. The Operating Companies operate as separate companies, each serving the customers in its service area. The preferred stock, first mortgage bonds and other debt obligations of the Operating Companies are outstanding securities of the issuing utility. All significant intercompany items have been eliminated in consolidation.

Centerior Energy and the Operating Companies follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission and adopted by The Public Utilities Commission of Ohio (PUCO). As rate-regulated utilities, the Operating Companies are subject to Statement of Financial Accounting Standards (SFAS) 71 which governs accounting for the effects of certain types of rate regulation. The Service Company follows the Uniform System of Accounts for Mutual Service Companies prescribed by the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935.

The Operating Companies are members of the Central Area Power Coordination Group (CAPCO). Other members are Duquesne Light Company, Ohio Edison Company and its wholly owned subsidiary, Pennsylvania Power Company. The members have constructed and operate generation and transmission facilities for their use.

(b) Revenues

Customers are billed on a monthly cycle basis for their energy consumption based on rate schedules or contracts authorized by the PUCO or on ordinances of individual municipalities. An accrual is made at the end of each month to record the estimated amount of unbilled revenues for kilowatt-hours sold in the current month but not billed by the end of that month.

A fuel factor is added to the base rates for electric service. This factor is designed to recover from customers the costs of fuel and most purchased power. It is reviewed and adjusted semiannually in a PUCO proceeding.

(c) Fuel Expense

The cost of fossil fuel is charged to fuel expense based on inventory usage. The cost of nuclear fuel, including an interest component, is charged to fuel expense based on the rate of consumption. Estimated future nuclear fuel disposal costs are being recovered through the base rates.

The Operating Companies defer the differences between actual fuel costs and estimated fuel costs currently being recovered from customers through the fuel factor. This matches fuel expenses with fuel-related revenues.

Owners of nuclear generating plants are assessed by the federal government for the cost of decontamination and decommissioning of nuclear enrichment facilities operated by the United States Department of Energy. The assessments are based upon the amount of enrichment services used in prior years and cannot be imposed for more than 15 years. The Operating Companies have accrued the liability for their share of the total assessments. These costs have been recorded in a deferred charge account since the PUCO is allowing the Operating Companies to recover the assessments through their fuel cost factors.

(d) Deferred Carrying Charges and Operating Expenses

The PUCO authorized the Operating Companies to defer operating expenses and carrying charges for Perry Unit 1 and Beaver Valley Power Station Unit 2 (Beaver Valley Unit 2) from their respective in-service dates in 1987 through December 1988. The annual amortization and recovery of these deferrals, called pre-phase-in deferrals, are $17 million which began in January 1989 and will continue over the lives of the related property.

Beginning in January 1989, the Operating Companies deferred certain operating expenses and both interest and equity carrying charges pursuant to PUCO-approved rate phase-in plans for their investments in Perry Unit 1 and Beaver Valley Unit 2. These deferrals, called phase-in deferrals, were written off at December 31, 1993. See Note 7.

The Operating Companies also defer certain costs not currently recovered in rates under a Rate Stabilization Program approved by the PUCO in October 1992. See Notes 7 and 14.

(e) Depreciation and Amortization

The cost of property, plant and equipment is depreciated over their estimated useful lives on a straight-line basis. The annual straight-line depreciation provision for non-nuclear property expressed as a percent of average depreciable utility plant in service was 3.5% in 1993 and 3.4% in both 1992 and 1991. Effective January 1, 1991, the Operating Companies, after obtaining PUCO approval, changed their method of accounting for nuclear plant depreciation from the units-of-production method to the straight-line method at about a 3% rate. This change decreased 1991 depreciation expense $36 million and increased 1991 net income $28 million (net of $8 million of income taxes) and earnings per share $.20 from what they otherwise would have been. The PUCO subsequently approved in 1991 a change to lower the 3% rate to 2.5% retroactive to January 1, 1991.

Pursuant to a PUCO order, the Operating Companies currently use external funding for the future decommissioning of their nuclear units at the end of their licensed operating lives. The estimated costs are based on the NRC's DECON method of decommissioning (prompt decontamination). Cash contributions are made to the trust funds on a straight-line basis over the remaining licensing period for each unit. The current level of annual expense being recovered from customers based on prior estimates is approximately $8 million. However, actual decommissioning costs are expected to significantly exceed those estimates. Current site-specific estimates for the Operating Companies' share of the future decommissioning costs are $92 million in 1992 dollars for Beaver Valley Unit 2 and $223 million and $300 million in 1993 dollars for Perry Unit 1 and the Davis-Besse Nuclear Power Station (Davis-Besse), respectively. The estimates for Perry Unit 1 and Davis-Besse are preliminary and are expected to be finalized by the end of the second quarter of 1994. The Operating Companies used these estimates to increase their decommissioning expense accruals in 1993. It is expected that the increases associated with the revised cost estimates will be recoverable in future rates. In the Balance Sheet at December 31, 1993, Accumulated Depreciation and Amortization included $74 million of decommissioning costs previously expensed and the earnings on the external funding. This amount exceeds the Balance Sheet amount of the external Nuclear Plant Decommissioning Trusts because the reserve began prior to the external trust funding.

(f) Property, Plant and Equipment

Property, plant and equipment are stated at original cost less amounts ordered by the PUCO to be written off. Construction costs include related payroll taxes, pensions, fringe benefits, management and general overheads and allowance for funds used during construction (AFUDC). AFUDC represents the estimated composite debt and equity cost of funds used to finance construction. This noncash allowance is credited to income. The AFUDC rates averaged 9.9% in 1993, 10.8% in 1992 and 10.7% in 1991.

Maintenance and repairs are charged to expense as incurred. The cost of replacing plant and equipment is charged to the utility plant accounts. The cost of property retired plus removal costs, after deducting any salvage value, is charged to the accumulated provision for depreciation.

(g) Deferred Gain and Loss from Sales of Utility Plant

The sale and leaseback transactions discussed in Note 2 resulted in a net gain for the sale of the Bruce Mansfield Generating Plant (Mansfield Plant) and a net loss for the sale of Beaver Valley Unit 2. The net gain and net loss were deferred and are being amortized over the terms of leases. These amortizations and the lease expense amounts are recorded as other operation and maintenance expenses.

(h) Interest Charges

Debt Interest reported in the Income Statement does not include interest on obligations for nuclear fuel under construction. That interest is capitalized. See Note 6.

Losses and gains realized upon the reacquisition or redemption of long-term debt are deferred, consistent with the regulatory rate treatment. Such losses and gains are either amortized over the remainder of the original life of the debt issue retired or amortized over the life of the new debt issue when the proceeds of a new issue are used for the debt redemption. The amortizations are included in debt interest expense.

(i) Federal Income Taxes

The Financial Accounting Standards Board (FASB) issued SFAS 109, a new standard for accounting for income taxes, in February 1992. We adopted the new standard in 1992. The standard amended certain provisions of SFAS 96 which we had previously adopted. Adoption of SFAS 109 in 1992 did not materially affect our results of operations, but did affect certain Balance Sheet accounts. See Note 8.

The financial statements reflect the liability method of accounting for income taxes. This method requires that deferred taxes be recorded for all temporary differences between the book and tax bases of assets and liabilities. The majority of these temporary differences are attributable to property-related basis differences. Included in these basis differences is the equity component of AFUDC, which will increase future tax expense when it is recovered through rates. Since this component is not recognized for tax purposes, we must record a liability for our tax obligation. The PUCO permits recovery of such taxes from customers when they become payable. Therefore, the net amount due from customers through rates has been recorded as a deferred charge and will be recovered over the lives of the related assets.

Investment tax credits are deferred and amortized over the lives of the applicable property as a reduction of depreciation expense. See Note 7 for a discussion of the amortization of certain unrestricted excess deferred taxes and unrestricted investment tax credits under the Rate Stabilization Program.

(2) Utility Plant Sale and Leaseback Transactions

The Operating Companies are co-lessees of 18.26% (150 megawatts) of Beaver Valley Unit 2 and 6.5% (51 megawatts), 45.9% (358 megawatts) and 44.38% (355 megawatts) of Units 1, 2 and 3 of the Mansfield Plant, respectively, all for terms of about 29½ years. These leases are the result of sale and leaseback transactions completed in 1987.

Under these leases, the Operating Companies are responsible for paying all taxes, insurance premiums, operation and maintenance expenses and all other similar costs for their interests in the units sold and leased back. They may incur additional costs in connection with capital improvements to the units. The Operating Companies have options to buy the interests back at the end of the leases for the fair market value at that time or to renew the leases. Additional lease provisions provide other purchase options along with conditions for mandatory termination of the leases (and possible repurchase of the leasehold interests) for events of default. These events include noncompliance with several financial covenants discussed in Note 11(e).

In April 1992, nearly all of the outstanding Secured Lease Obligation Bonds (SLOBs) issued by a special purpose corporation in connection with financing the sale and leaseback of Beaver Valley Unit 2 were refinanced through a tender offer and the sale of new bonds having a lower interest rate. As part of the refinancing transaction, Toledo Edison paid $43 million as supplemental rent to fund transaction expenses and part of the tender premium. This amount has been deferred and is being amortized over the remaining lease term. The refinancing transaction reduced the annual rental expense for the Beaver Valley Unit 2 lease by $9 million.

Future minimum lease payments under the operating leases at December 31, 1993 are summarized as follows:

Year	Amount (millions of dollars)
1994	$ 166
1995	165
1996	188
1997	165
1998	165
Later Years	3,412
Total Future Minimum Lease Payments	$4,261

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1993, 1992 and 1991 as annual rental expense for the Mansfield Plant leases was $115 million. The amounts recorded in 1993, 1992 and 1991 as annual rental expense for the Beaver Valley Unit 2 lease were $63 million, $66 million and $72 million, respectively. Amounts charged to expense in excess of the lease payments are classified as Accumulated Deferred Rents in the Balance Sheet.

Toledo Edison is selling 150 megawatts of its Beaver Valley Unit 2 leased capacity entitlement to Cleveland Electric. We anticipate that this sale will continue indefinitely.

(3) Property Owned with Other Utilities and Investors

The Operating Companies own, as tenants in common with other utilities and those investors who are owner-participants in various sale and leaseback transactions (Lessors), certain generating units as listed below. Each owner owns an undivided share in the entire unit. Each owner has the right to a percentage of the generating capability of each unit equal to its ownership share. Each utility owner is obligated to pay for only its respective share of the construction costs and operating expenses. Each Lessor has leased its capacity rights to a utility which is obligated to pay for such Lessor's share of the construction costs and operating expenses. The Operating Companies' share of the operating expenses of these generating units is included in the Income Statement. The Balance Sheet classification of Property, Plant and Equipment at December 31, 1993 includes the following facilities owned by the Operating Companies as tenants in common with other utilities and Lessors:

Generating Unit	In-Service Date	Ownership Share	Ownership Megawatts	Power Source	Plant in Service	Construction Work in Progress	Accumulated Depreciation
					(millions of dollars)		
Seneca Pumped Storage	1970	80.00%	351	Hydro	$ 67	$—	$ 22
Eastlake Unit 5	1972	68.80	411	Coal	156	2	—
Perry Unit 1	1987	51.02	609	Nuclear	2,832	11	473
Beaver Valley Unit 2 and Common Facilities (Note 2)	1987	26.12	214	Nuclear	1,480	5	255
Total					$4,535	$18	$750

Depreciation for Eastlake Unit 5 has been accumulated with all other nonnuclear depreciable property rather than by specific units of depreciable property.

(4) Construction and Contingencies

(a) Construction Program

The estimated cost of our construction program for the 1994-1998 period is $1.088 billion, including AFUDC of $48 million and excluding nuclear fuel.

The Clean Air Act will require, among other things, significant reductions in the emission of sulfur dioxide in two phases over a ten-year period and nitrogen oxides by fossil-fueled generating units.

Our compliance strategy provides for compliance with both phases through at least 2005 primarily through greater use of low-sulfur coal at some of our units and the banking of emission allowances. The plan will require capital expenditures over the 1994-2003 period of approximately $222 million for nitrogen oxide control equipment, emission monitoring equipment and plant modifications. In addition, higher fuel and other operation and maintenance expenses will be incurred. The anticipated rate increase associated with the capital expenditures and higher expenses would be about 1-2% in the late 1990s. Cleveland Electric may need to install sulfur emission control technology at one of its generating plants after 2005 which could require additional expenditures at that time. The PUCO has approved this plan. We also are seeking United States Environmental Protection Agency (U.S. EPA) approval of the first phase of our plan.

We are continuing to monitor developments in new technologies that may be incorporated into our compliance strategy. If a different plan is required by the U.S. EPA, significantly higher capital expenditures could be required during the 1994-2003 period. We believe Ohio law permits the recovery of compliance costs from customers in rates.

(b) Perry Unit 2

Perry Unit 2, including its share of the facilities common with Perry Unit 1, was approximately 50% complete when construction was suspended in 1985 pending consideration of various options. These options included resumption of full construction with a revised estimated cost, conversion to a nonnuclear design, sale of all or part of our ownership share, or cancellation.

We wrote off our investment in Perry Unit 2 at December 31, 1993 after we determined that it would not be completed or sold. The write-off totaled $583 million ($425 million after taxes) for our 64.76% ownership share of the unit. See Note 14.

(c) Hazardous Waste Disposal Sites

The Operating Companies are aware of their potential involvement in the cleanup of three sites listed on the Superfund List and several other waste sites not on such list. The Operating Companies have accrued a liability totaling $19 million at December 31, 1993 based on estimates of the costs of cleanup and their proportionate responsibility for such costs. We believe that the ultimate outcome of these matters will not have a material adverse effect on our financial condition or results of operations. See Management's Financial Analysis — Outlook–Hazardous Waste Disposal Sites.

(5) Nuclear Operations and Contingencies

(a) Operating Nuclear Units

Our three nuclear units may be impacted by activities or events beyond our control. An extended outage of one of our nuclear units for any reason, coupled with any unfavorable rate treatment, could have a material adverse effect on our financial condition and results of operations. See discussion of these risks in Management's Financial Analysis — Outlook-Nuclear Operations.

(b) Nuclear Insurance

The Price-Anderson Act limits the liability of the owners of a nuclear power plant to the amount provided by private insurance and an industry assessment plan. In the event of a nuclear incident at any unit in the United States resulting in losses in excess of the level of private insurance (currently $200 million), our maximum potential assessment under that plan would be $155 million (plus any inflation adjustment) per incident. The assessment is limited to $20 million per year for each nuclear incident. These assessment limits assume the other CAPCO companies contribute their proportionate share of any assessment.

The CAPCO companies have insurance coverage for damage to property at the Davis-Besse, Perry and Beaver Valley sites (including leased fuel and clean-up costs). Coverage amounted to $2.75 billion for each site as of January 1, 1994. Damage to property could exceed the insurance coverage by a substantial amount. If it does, our share of such excess amount could have a material adverse effect on our financial condition and results of operations. Under these policies, we can be assessed a maximum of $25 million during a policy year if the reserves available to the insurer are inadequate to pay claims arising out of an accident at any nuclear facility covered by the insurer.

We also have extra expense insurance coverage. It includes the incremental cost of any replacement power purchased (over the costs which would have been incurred had the units been operating) and other incidental expenses after the occurrence of certain types of accidents at our nuclear units. The amounts of the coverage are 100% of the estimated extra expense per week during the 52-week period starting 21 weeks after an accident and 67% of such estimate per week for the next 104 weeks. The amount and duration of extra expense could substantially exceed the insurance coverage.

(6) Nuclear Fuel

Nuclear fuel is financed for the Operating Companies through leases with a special-purpose corporation. The total amount of financing currently available under these lease arrangements is $382 million ($232 million from intermediate-term notes and $150 million from bank credit arrangements). Financing in an amount up to $750 million is permitted. The intermediate-term notes mature in the period 1994-1997, with $75 million maturing in September 1994. At December 31, 1993, $370 million of nuclear fuel was financed. The Operating Companies severally lease their respective portions of the nuclear fuel and are obligated to pay for the fuel as it is consumed in a reactor. The lease rates are based on various intermediate-term note rates, bank rates and commercial paper rates.

The amounts financed include nuclear fuel in the Davis-Besse, Perry Unit 1 and Beaver Valley Unit 2 reactors with remaining lease payments of $110 million, $78 million and $46 million, respectively, at December 31, 1993. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $14 million in 1993, $15 million in 1992 and $21 million in 1991. The estimated future lease amortization payments based on projected consumption are $111 million in 1994, $97 million in 1995, $87 million in 1996, $77 million in 1997 and $69 million in 1998.

(7) Regulatory Matters

Phase-in deferrals were recorded beginning in 1989 pursuant to the phase-in plans approved by the PUCO in January 1989 rate orders for the Operating Companies. The phase-in plans were designed so that the projected revenues resulting from the authorized rate increases and anticipated sales growth provided for the phase-in of certain nuclear costs over a ten-year period. The plans required the deferral of a portion of the operating expenses and both interest and equity carrying charges on the Operating Companies' deferred rate-based investments in Perry Unit 1 and Beaver Valley Unit 2 during the early years of the plans. The amortization and recovery of such deferrals were scheduled to be completed by 1998.

As we developed our strategic plan, we evaluated the future recovery of our deferred charges and continued application of the regulatory accounting measures we follow pursuant to PUCO orders. We concluded that projected revenues would not provide for the recovery of the phase-in deferrals as scheduled because of economic and competitive pressures. Accordingly, we wrote off the cumulative balance of the phase-in deferrals. The total phase-in deferred operating expenses and carrying charges written off at December 31, 1993 were $172 million and $705 million, respectively (totaling $598 million after taxes). See Note 14. While recovery of our other regulatory deferrals remains probable, our current assessment of business conditions has prompted us to change our future plans. We decided that, once the deferral of expenses and acceleration of benefits under our Rate Stabilization Program are completed in 1995, we should no longer plan to use regulatory accounting measures to the extent we have in the past.

In October 1992, the PUCO approved a Rate Stabilization Program that was designed to encourage economic growth in our service area by freezing base rates until 1996 and limiting subsequent rate increases to specified annual amounts not to exceed $216 million for Cleveland Electric and $89 million for Toledo Edison over the 1996-1998 period.

As part of the Rate Stabilization Program, the Operating Companies are allowed to defer and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. Such regulatory accounting measures provide for rate stabilization by rescheduling the timing of rate recovery of certain costs and the amortization of certain benefits during the 1992-1995 period. The continued use of these regulatory accounting measures will be dependent upon our continuing assessment and conclusion that there will be probable recovery of such deferrals in future rates.

The regulatory accounting measures we are eligible to record through December 31, 1995 include the deferral of post-in-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988 and the deferral of Toledo Edison operating expenses equivalent to an accumulated excess rent reserve for Beaver Valley Unit 2 (which resulted from the April 1992 refinancing of SLOBs as discussed in Note 2). The cost deferrals recorded in 1993 and 1992 pursuant to these provisions were $95 million and $84 million, respectively. Amortization and recovery of these deferrals will occur over the average life of the related assets and the remaining lease period, or approximately 30 years, and will commence with future rate recognition. The regulatory accounting measures also provide for the accelerated amortization of certain unrestricted excess deferred tax and unrestricted investment tax credit balances and interim spent fuel storage accrual balances for Davis-Besse. The total amount of such regulatory benefits recognized in 1993 and 1992 pursuant to these provisions was $46 million and $12 million, respectively.

The Rate Stabilization Program also authorized the Operating Companies to defer and subsequently recover the incremental expenses associated with the adoption of the accounting standard for postretirement benefits other than pensions (SFAS 106). In 1993, we deferred $96 million pursuant to this provision. Amortization and recovery of this deferral will commence prior to 1998 and is expected to be completed by no later than 2012. See Note 9(b).

(8) Federal Income Tax

Federal income tax, computed by multiplying the income before taxes and preferred dividend requirements of subsidiaries by the statutory rate (35% in 1993 and 34% in both 1992 and 1991), is reconciled to the amount of federal income tax recorded on the books as follows:

	1993	1992	1991
	(millions of dollars)		
Book Income (Loss) Before Federal Income Tax	$(1,263)	$406	$466
Tax (Credit) on Book Income (Loss) at Statutory Rate	$ (442)	$138	$158
Increase (Decrease) in Tax:			
Write-off of Perry Unit 2	46	—	—
Write-off of phase-in deferrals	28	—	—
Depreciation	(6)	(9)	1
Rate Stabilization Program	(30)	(7)	—
Other items	17	7	9
Total Federal Income Tax Expense (Credit)	$ (387)	$129	$168

Federal income tax expense is recorded in the Income Statement as follows:

	1993	1992	1991
	(millions of dollars)		
Operating Expenses:			
Current Tax Provision	$ 99	$ 71	$ 88
Changes in Accumulated Deferred Federal Income Tax:			
Write-off of deferred operating expenses	(39)	—	—
Accelerated depreciation and amortization	95	39	17
Alternative minimum tax credit	(57)	(31)	(46)
Retirement and postemployment benefits	(43)	—	—
Sale and leaseback transactions and amortization	9	8	4
Taxes, other than federal income taxes	(25)	19	—
Rate Stabilization Program	(9)	4	—
Reacquired debt costs	(3)	10	22
Deferred fuel costs	(2)	(1)	(9)
Other items	(14)	3	23
Investment Tax Credits	—	—	39
Total Charged to Operating Expenses	11	122	138
Nonoperating Income:			
Current Tax Provision	(34)	(38)	(46)
Changes in Accumulated Deferred Federal Income Tax:			
Write-off of deferred carrying charges	(240)	—	—
Write-off of Perry Unit 2	(158)	—	—
Disallowed nuclear costs	20	14	—
Rate Stabilization Program	11	11	—
AFUDC and carrying charges	12	24	41
Net operating loss carryforward	(7)	—	35
Other items	(2)	(4)	—
Total Expense (Credit) to Nonoperating Income	(398)	7	30
Total Federal Income Tax Expense (Credit)	$(387)	$ 129	$ 168

In August 1993, the 1993 Tax Act was enacted. Retroactive to January 1, 1993, the top marginal corporate income tax rate increased to 35%. The change in tax rate increased Accumulated Deferred Federal Income Taxes for the future tax obligation by approximately $90 million. Since the PUCO has historically permitted recovery of such taxes from customers when they become payable, the deferred charge, Amounts Due from Customers for Future Federal Income Taxes, also was increased by $90 million. The 1993 Tax Act is not expected to materially impact future results of operations or cash flow.

Under SFAS 109, temporary differences and carryforwards resulted in deferred tax assets of $619 million and deferred tax liabilities of $2.198 billion at December 31, 1993 and deferred tax assets of $563 million and deferred tax liabilities of $2.598 billion at December 31, 1992. These are summarized as follows:

	December 31, 1993	1992
	(millions of dollars)	
Property, plant and equipment	$1,845	$2,125
Deferred carrying charges and operating expenses	206	368
Net operating loss carryforwards	(108)	(137)
Investment tax credits	(183)	(190)
Other	(181)	(131)
Net deferred tax liability	$1,579	$2,035

For tax purposes, net operating loss (NOL) carryforwards of approximately $309 million are available to reduce future taxable income and will expire in 2003 through 2005. The 35% tax effect of the NOLs is $108 million.

The Tax Reform Act of 1986 provides for an alternative minimum tax (AMT) credit to be used to reduce the regular tax to the AMT level should the regular tax exceed the AMT. AMT credits of $171 million are available to offset future regular tax. The credits may be carried forward indefinitely.

(9) Retirement and Postemployment Benefits

(a) Retirement Income Plan

We sponsor a noncontributing pension plan which covers all employee groups. Two existing plans were merged into a single plan on December 31, 1993. The amount of retirement benefits generally depends upon the length of service. Under certain circumstances, benefits can begin as early as age 55. Our funding policy is to comply with the Employee Retirement Income Security Act of 1974 guidelines.

In 1993, we offered the VTP, an early retirement program. Operating expenses for 1993 included $205 million of pension plan accruals to cover enhanced VTP benefits and an additional $10 million of pension costs for VTP benefits paid to retirees from corporate funds. The $10 million is not included in the pension data reported below. A credit of $81 million resulting from a settlement of pension obligations through lump sum payments to almost all the VTP retirees partially offset the VTP expenses.

Net pension and VTP costs (credits) for 1991 through 1993 were comprised of the following components:

	1993	1992	1991
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 15	$ 15	$ 14
Interest cost on projected benefit obligation	37	38	36
Actual return on plan assets	(65)	(24)	(129)
Net amortization and deferral	4	(45)	65
Net pension costs (credits)	(9)	(16)	(14)
VTP cost	205	—	—
Settlement gain	(81)	—	—
Net costs (credits)	$115	$(16)	$ (14)

The following table presents a reconciliation of the funded status of the plan(s) at December 31, 1993 and 1992.

	1993	1992
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$333	$310
Nonvested benefits	37	40
Accumulated benefit obligation	370	350
Effect of future compensation levels	53	121
Total projected benefit obligation	423	471
Plan assets at fair market value	386	754
Funded status	(37)	283
Unrecognized net loss (gain) from variance between assumptions and experience	11	(140)
Unrecognized prior service cost	10	12
Transition asset at January 1, 1987 being amortized over 19 years	(43)	(99)
Net prepaid pension cost (accrued pension liability) included in other deferred charges (credits) in the Balance Sheet	$(59)	$ 56

At December 31, 1993, the settlement (discount) rate and long-term rate of return on plan assets assumptions were 7.25% and 8.75%, respectively. The long-term rate of annual compensation increase assumption was 4.25%. At December 31, 1992, the settlement rate and long-term rate of return on plan assets assumptions were 8.5% and the long-term rate of annual compensation increase assumption was 5%.

Plan assets consist primarily of investments in common stock, bonds, guaranteed investment contracts, cash equivalent securities and real estate.

(b) Other Postretirement Benefits

We sponsor a postretirement benefit plan which provides all employee groups certain health care, death and other postretirement benefits other than pensions. The plan is contributory, with retiree contributions adjusted annually. The plan is not funded. A policy limiting the employer's contribution for retiree medical coverage for employees retiring after March 31, 1993 was implemented in February 1993.

We adopted SFAS 106, the accounting standard for postretirement benefits other than pensions, effective January 1, 1993. The standard requires the accrual of the expected costs of such benefits during the employees' years of service. Previously, the costs of these benefits were expensed as paid, which is consistent with ratemaking practices. Such costs totaled $9 million in 1992 and $10 million in 1991, which included medical benefits of $8 million in 1992 and $9 million in 1991. The total amount accrued for SFAS 106 costs for 1993 was $111 million, of which $5 million was capitalized and $106 million was expensed as other operation and maintenance expenses. In 1993, we deferred incremental SFAS 106 expenses totaling $96 million pursuant to a provision of the Rate Stabilization Program. See Note 7.

The components of the total postretirement benefit costs for 1993 were as follows:

	Millions of Dollars
Service cost for benefits earned	$ 3
Interest cost on accumulated postretirement benefit obligation	16
Amortization of transition obligation at January 1, 1993 of $167 million over 20 years	8
VTP curtailment cost (includes $16 million transition obligation adjustment)	84
Total costs	$111

The accumulated postretirement benefit obligation and accrued postretirement benefit cost at December 31, 1993 are summarized as follows:

	Millions of Dollars
Accumulated postretirement benefit obligation attributable to:	
Retired participants	$(229)
Fully eligible active plan participants	(1)
Other active plan participants	(28)
Accumulated postretirement benefit obligation	(258)
Unrecognized net loss from variance between assumptions and experience	14
Unamortized transition obligation	143
Accrued postretirement benefit cost included in other noncurrent liabilities in the Balance Sheet	$(101)

At December 31, 1993, the settlement rate and the long-term rate of annual compensation increase assumptions were 7.25% and 4.25%, respectively. The assumed annual health care cost trend rates (applicable to gross eligible charges) are 9.5% for medical and 8% for dental in 1994. Both rates reduce gradually to a fixed rate of 4.75% in 1996 and later years. Elements of the obligation affected by contribution caps are significantly less sensitive to the health care cost trend rate than other elements. If the assumed health care cost trend rates were increased by 1% in each future year, the accumulated postretirement benefit obligation as of December 31, 1993 would increase by $11 million and the aggregate of the service and interest cost components of the annual postretirement benefit cost would increase by $1 million.

(c) Postemployment Benefits

In 1993, we adopted SFAS 112, the new accounting standard which requires the accrual of postemployment benefit costs. Postemployment benefits are the benefits provided to former or inactive employees after employment but before retirement, such as worker's compensation, disability benefits and severance pay. The adoption of this accounting method did not materially affect our 1993 results of operations or financial position.

(10) Guarantees

Cleveland Electric has guaranteed certain loan and lease obligations of two mining companies under two long-term coal purchase arrangements. Toledo Edison is also a party to one of these guarantee arrangements. This arrangement requires payments to the mining company for any actual expenses (as advance payments for coal) when the mines are idle for reasons beyond the control of the mining company. At December 31, 1993, the principal amount of the mining companies' loan and lease obligations guaranteed by the Operating Companies was $80 million.

(11) Capitalization

(a) Capital Stock Transactions

Shares sold, retired and purchased for treasury during the three years ended December 31, 1993 are listed in the following tables.

	1993	1992	1991
	(thousands of shares)		
Centerior Energy Common Stock:			
Dividend Reinvestment and Stock Purchase Plan	3,542	2,570	1,422
Employee Savings Plan	544	322	348
Employee Purchase Plan	52	—	—
Total Common Stock Sales	4,138	2,892	1,770
Treasury Shares	26	(172)	(11)
Net Increase	4,164	2,720	1,759

	1993	1992	1991
	(thousands of shares)		
Preferred Stock of Subsidiaries Subject to Mandatory Redemption:			
Cleveland Electric Sales			
$ 91.50 Series Q	—	—	75
88.00 Series R	—	—	50
90.00 Series S	—	75	—
Cleveland Electric Retirements			
$ 7.35 Series C	(10)	(10)	(10)
88.00 Series E	(3)	(3)	(3)
75.00 Series F	—	—	(2)
145.00 Series I	—	—	(14)
113.50 Series K	—	—	(10)
Adjustable Series M	(100)	(100)	(100)
9.125 Series N	(150)	—	—
Toledo Edison Retirements			
$100 par $11.00	—	(25)	(10)
9.375	(17)	(17)	(17)
25 par 2.81	(800)	—	—
Preferred Stock of Subsidiaries Not Subject to Mandatory Redemption:			
Cleveland Electric Sales			
$ 42.40 Series T	200	—	—
Cleveland Electric Retirements			
Remarketed Series P	—	(1)	—
Net (Decrease)	(880)	(81)	(41)

Shares of common stock required for our stock plans in 1993 were either acquired in the open market, issued as new shares or issued from treasury stock.

The Board of Directors has authorized the purchase in the open market of up to 1,500,000 shares of our common stock until June 30, 1994. As of December 31, 1993, 225,500 shares had been purchased at a total cost of $4 million. Such shares are being held as treasury stock.

(b) Common Shares Reserved for Issue

Common shares reserved for issue under the Employee Savings Plan and the Employee Purchase Plan were 1,962,174 and 469,457 shares, respectively, at December 31, 1993.

Stock options to purchase unissued shares of common stock under the 1978 Key Employee Stock Option Plan were granted at an exercise price of 100% of the fair market value at the date of the grant. No additional options may be granted. The exercise prices of option shares purchased during the three years ended December 31, 1993 ranged from $14.09 to $17.41 per share. Shares and price ranges of outstanding options held by employees were as follows:

	1993	1992	1991
Options Outstanding at December 31:			
Shares	37,627	93,312	129,798
Option Prices	$14.09 to $20.73	$14.09 to $20.73	$14.09 to $20.73

(c) Equity Distribution Restrictions

The Operating Companies make cash available for the funding of Centerior Energy's common stock dividends by paying dividends on their respective common stock, which are held solely by Centerior Energy. Federal law prohibits the Operating Companies from paying dividends out of capital accounts. However, the Operating Companies may pay preferred and common stock dividends out of appropriated retained earnings and current earnings. At December 31, 1993, Cleveland Electric and Toledo Edison had $125 million and $42 million, respectively, of appropriated retained earnings for the payment of dividends. However, Toledo Edison is prohibited from paying a common stock dividend by a provision in its mortgage.

(d) Preferred and Preference Stock

Amounts to be paid for preferred stock which must be redeemed during the next five years are $40 million in 1994, $51 million in 1995, $41 million in 1996, $31 million in 1997 and $16 million in 1998.

The annual mandatory redemption provisions are as follows:

	Shares To Be Redeemed	Beginning in	Price Per Share
Cleveland Electric Preferred:			
$ 7.35 Series C	10,000	1984	$ 100
88.00 Series E	3,000	1981	1,000
Adjustable Series M	100,000	1991	100
9.125 Series N	150,000	1993	100
91.50 Series Q	10,714	1995	1,000
88.00 Series R	50,000	2001*	1,000
90.00 Series S	18,750	1999	1,000
Toledo Edison Preferred:			
$100 par $9.375	16,650	1985	100
25 par 2.81	400,000	1993	25

* All outstanding shares to be redeemed on December 1, 2001.

In June 1993, Cleveland Electric issued $100 million principal amount of Serial Preferred Stock, $42.40 Series T. The Series T stock was deposited with an agent which issued Depositary Receipts, each representing 1/20 of a share of the Series T stock.

The annualized preferred dividend requirement for the Operating Companies at December 31, 1993 was $68 million.

The preferred dividend rates on Cleveland Electric's Series L and M and Toledo Edison's Series A and B fluctuate based on prevailing interest rates and market conditions. The dividend rates for these issues averaged 7%, 7%, 7.41% and 8.22%, respectively, in 1993. Cleveland Electric's Series P had a 6.5% dividend rate in 1993 until it was redeemed in August 1993.

Preference stock authorized for the Operating Companies are 3,000,000 shares without par value for Cleveland Electric and 5,000,000 shares with a $25 par value for Toledo Edison. No preference shares are currently outstanding for either company.

With respect to dividend and liquidation rights, each Operating Company's preferred stock is prior to its preference stock and common stock, and each Operating Company's preference stock is prior to its common stock.

(e) Long-Term Debt and Other Borrowing Arrangements

Long-term debt, less current maturities, for the Operating Companies was as follows:

Year of Maturity	Actual or Average Interest Rate at December 31, 1993	December 31, 1993	December 31, 1992
		(millions of dollars)	
First mortgage bonds:			
1994	4.375%	$ —	$ 25
1994	13.75	—	4
1995	13.75	4	4
1995	7.00	1	1
1996	13.75	4	4
1996	7.00	1	1
1997	10.88	6	6
1997	13.75	4	4
1997	7.00	1	1
1997	6.125	31	31
1998	10.88	6	6
1998	13.75	4	4
1998	7.00	1	1
1998	10.00	1	1
1999-2003	7.89	568	468
2004-2008	8.14	260	264
2009-2013	7.68	436	436
2014-2018	8.07	513	513
2019-2023	7.89	733	583
		2,574	2,357
Secured medium term notes due 1995-2021	8.77	963	860
Term bank loans due 1995-1996	7.41	154	121
Notes due 1995-1997	9.63	43	60
Debentures due 2002	8.70	135	135
Pollution control notes due 1995-2015	10.11	158	158
Other — net	—	(8)	3
Total Long-Term Debt		$4,019	$3,694

Long-term debt matures during the next five years as follows: $87 million in 1994, $317 million in 1995, $242 million in 1996, $94 million in 1997 and $117 million in 1998.

The Operating Companies issued $550 million aggregate principal amount of secured medium-term notes during the 1991-1993 period. The notes are secured by first mortgage bonds.

The mortgages of the Operating Companies constitute direct first liens on substantially all property owned and franchises held by them. Excluded from the liens, among other things, are cash, securities, accounts receivable, fuel, supplies and, in the case of Toledo Edison, automotive equipment.

Certain unsecured loan agreements of the Operating Companies contain covenants relating to capitalization ratios, fixed charge coverage ratios and limitations on secured financing other than through first mortgage bonds or certain other transactions. Two reimbursement agreements relating to separate letters of credit issued in connection with the sale and leaseback of Beaver Valley Unit 2 contain several financial covenants affecting Centerior Energy and the Operating Companies. Among these are covenants relating to fixed charge coverage ratios and capitalization ratios. The write-offs recorded at December 31, 1993 caused Centerior Energy and the Operating Companies to violate certain covenants contained in a Cleveland Electric loan agreement and the two reimbursement agreements. The affected creditors have waived those violations in exchange for our commitment to provide them with a second mortgage security interest on our property and other considerations. We expect to complete this process in the second quarter of 1994. We will provide the same security interest to certain other creditors because their agreements require equal treatment. We expect to provide second mortgage collateral for $219 million of unsecured debt, $228 million of bank letters of credit and a $205 million revolving credit facility.

(12) Short-Term Borrowing Arrangements

In May 1993, Centerior Energy arranged for a $205 million, three-year revolving credit facility. The facility may be renewed twice for one-year periods at the option of the participating banks. Centerior Energy and the Service Company may borrow under the facility, with all borrowings jointly and severally guaranteed by the Operating Companies. Centerior Energy plans to transfer any of its borrowed funds to the Operating Companies, while the Service Company may borrow up to $25 million for its own use. The banks' fee is 0.5% per annum payable quarterly in addition to interest on any borrowings. That fee is expected to increase to 0.625% when the facility agreement is amended as discussed below. There were no borrowings under the facility at December 31, 1993. The facility agreement contains covenants relating to capitalization and fixed charge coverage ratios. The write-offs recorded at December 31, 1993 caused the ratios to fall below those covenant requirements. The revolving credit facility is expected to be available for borrowings after the facility agreement is amended in the second quarter of 1994 to provide the participating creditors with a second mortgage security interest.

Short-term borrowing capacity authorized by the PUCO annually is $300 million for Cleveland Electric and $150 million for Toledo Edison. The Operating Companies are authorized by the PUCO to borrow from each other on a short-term basis.

At December 31, 1993, the Operating Com`anies had no commercial paper outstanding. The Operating Companies are unable to rely on the sale of commercial paper to provide short-term funds because of their below investment grade commercial paper credit ratings.

(13) Financial Instruments' Fair Value

The estimated fair values at December 31, 1993 and 1992 of financial instruments that do not approximate their carrying amounts are as follows:

	December 31,			
	1993		1992	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(millions of dollars)			
Nuclear Plant Decommissioning Trusts	$ 56	$ 59	$ 42	$ 4[illegible]
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	354	349	405	408
Long-Term Debt (including current portion)	4,113	4,260	4,017	4,107

The fair value of the nuclear plant decommissioning trusts is estimated based on the quoted market prices for the investment securities. The fair value of the Operating Companies' preferred stock with mandatory redemption provisions and long-term debt is estimated based on the quoted market prices for the respective or similar issues or on the basis of the discounted value of future cash flows. The discounted value used current dividend or interest rates (or other appropriate rates) for similar issues and loans with the same remaining maturities.

The estimated fair values of all other financial instruments approximate their carrying amounts in the Balance Sheet at December 31, 1993 and 1992 because of their short-term nature.

(14) Quarterly Results of Operations (Unaudited)

The following is a tabulation of the unaudited quarterly results of operations for the two years ended December 31, 1993.

	Quarters Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
	(millions of dollars, except per share amounts)			
1993				
Operating Revenues	$598	$589	$709	$ 578
Operating Income (Loss)	$122	$126	$106	$ (42)
Net Income (Loss)	$ 35	$ 34	$ 17	$(1,029)
Average Common Shares (millions)	143.4	144.4	145.3	146.4
Earnings (Loss) Per Common Share	$ .25	$ .23	$ .12	$ (7.02)
Dividends Paid Per Common Share	$ .40	$ .40	$ .40	$ .40
1992				
Operating Revenues	$592	$581	$665	$ 600
Operating Income	$122	$115	$191	$ 109
Net Income	$ 23	$ 20	$122	$ 47
Average Common Shares (millions)	140.6	141.6	142.0	142.5
Earnings Per Common Share	$ .16	$ .14	$ .86	$ .33
Dividends Paid Per Common Share	$ .40	$ .40	$ .40	$ .40

Earnings for the quarter ended September 30, 1993 were decreased by $81 million, or $.56 per share, as a result of the recording of $125 million of VTP pension-related benefits.

Earnings for the quarter ended December 31, 1993 were decreased as a result of year-end adjustments for the $583 million write-off of Perry Unit 2 (see Note 4(b)), the $877 million write-off of the phase-in deferrals (see Note 7) and $58 million of other charges. These adjustments decreased quarterly earnings by $1.06 billion, or $7.24 per share.

Earnings for the quarter ended September 30, 1992 were increased by $41 million, or $.29 per share, as a result of the recording of deferred operating expenses and carrying charges for the first nine months of 1992 totaling $61 million under the Rate Stabilization Program approved by the PUCO in October 1992. See Note 7.

EXECUTIVES OF CENTERIOR ENERGY CORPORATION

Chairman, President and Chief Executive Officer	*Robert J. Farling (57)*
Executive Vice President	*Murray R. Edelman (54)*
Senior Vice President	*Fred J. Lange, Jr. (44)*
Vice President	*Gary R. Leidich (43)*
Vice President	*Terrence G. Linnert (47)*
Controller	*Paul G. Busby (45)*
Treasurer	*Gary M. Hawkinson (45)*
Secretary	*E. Lyle Pepin (52)*

EXECUTIVES OF CENTERIOR SERVICE COMPANY

Chairman, President and Chief Executive Officer (and Chairman & CEO of Cleveland Electric and Toledo Edison)	*Robert J. Farling (57)*
Executive Vice President–Operations & Engineering (and Vice Chairman of Toledo Edison and President of Cleveland Electric)	*Murray R. Edelman (54)*
Senior Vice President–Fossil & Transmission and Distribution Operations (and President of Toledo Edison)	*Fred J. Lange, Jr. (44)*
Senior Vice President–Nuclear	*Donald C. Shelton (60)*
Vice President–Customer Support	*Jacquita K. Hauserman (51)*
Vice President–Finance & Administration	*Gary R. Leidich (43)*
Vice President–Legal & Governmental Affairs and General Counsel	*Terrence G. Linnert (47)*
Vice President–Transmission & Distribution Operations	*David L. Monseau (53)*
Vice President–Nuclear-Perry	*Robert A. Stratman (45)*
Vice President–Marketing	*Al R. Temple* (48)*
Controller	*Paul G. Busby (45)*
Treasurer	*Gary M. Hawkinson (45)*
Secretary	*E. Lyle Pepin (52)*

Number in parenthesis indicates age.

(*) Elected effective February 28, 1994.

FINANCIAL AND STATISTICAL REVIEW

Operating Revenues (millions of dollars)

Year	Residential	Commercial	Industrial	Other	Total Retail	Wholesale	Total Electric	Steam Heating & Gas	Total Operating Revenues
1993	$768	716	754	143	2 381	93	2 474	—	$2 474
1992	732	706	766	143	2 347	91	2 438	—	2 438
1991	777	723	783	188	2 471	89	2 560	—	2 560
1990	719	669	779	190	2 357	70	2 427	—	2 427
1989	686	617	747	204	2 254	107	2 361	—	2 361
1983	546	440	600	83	1 669	29	1 698	25	1 723

Operating Expenses (millions of dollars)

Year	Fuel & Purchased Power	Other Operation & Maintenance	Depreciation & Amortization	Taxes, Other Than FIT	Deferred Operating Expenses, Net	Federal Income Taxes	Total Operating Expenses
1993	$474	1 083(a)	258	312	23(b)	11	$2 161
1992	473	784	256	318	(52)	122	1 901
1991	500	801	243(c)	305	(6)	138	1 981
1990	472	863	242	283	(34)	96	1 922
1989	473	860	273	260	(59)	122	1 929
1983	464	384	145	172	—	184	1 349

Income (Loss) (millions of dollars)

Year	Operating Income	AFUDC—Equity	Other Income & Deductions, Net	Deferred Carrying Charges, Net	Federal Income Tax—Credit (Expense)	Income (Loss) Before Interest Charges	Debt Interest
1993	$313	5	(589)(d)	(649)(b)	398	(522)	359
1992	537	2	9	100	(7)	641	365
1991	579	9	6	110	(30)	674	381
1990	505	8	(1)	205	(13)	704	384
1989	432	17	14	299	(73)	689	369
1983	374	153	5	—	47	579	258

Income (Loss) (millions of dollars) Common Stock (dollars per share & %)

Year	AFUDC—Debt	Preferred & Preference Stock Dividends	Net Income (Loss)	Average Shares Outstanding (millions)	Earnings (Loss)	Return on Average Common Stock Equity	Dividends Declared	Book Value
1993	$ (5)	67	$(943)	144.9	$(6.51)	(40.3)%	$1.60	$12.14
1992	(1)	65	212	141.7	1.50	7.4	1.60	20.22
1991	(5)	61	237	139.1	1.71	8.4	1.60	20.37
1990	(6)	62	264	138.9	1.90	9.4	1.60	20.30
1989	(13)	66	267	140.5	1.90	9.6	1.60	19.99
1983	(54)	69	306	98.2(e)	3.11(e)	15.7	2.19(e)	20.24(e)

NOTE: 1983 data is the result of combining and restating data for the Operating Companies.

(a) Includes early retirement program expenses and other charges of $272 million in 1993.

(b) Includes write-off of phase-in deferrals of $877 million in 1993, consisting of $172 million of deferred operating expenses and $705 million of deferred carrying charges.

(c) In 1991, the Operating Companies adopted a change in accounting for nuclear plant depreciation, changing from the units-of-production method to the straight-line method at a 2.5% rate.

BOARD OF DIRECTORS

Richard P. Anderson *(64)* President and Chief Executive Officer of The Andersons Management Corporation, a grain, farm supply and retailing firm. 1986

Albert C. Bersticker *(59)* President and Chief Executive Officer of Ferro Corporation, a producer of specialty chemical materials for manufactured products. 1990

Leigh Carter *(68)* Retired President and Chief Operating Officer of The BFGoodrich Company, a producer of chemicals, plastics and aerospace products. Retired Chairman of Tremco, Incorporated, a manufacturer of specialty chemical products and a wholly owned subsidiary of The BFGoodrich Company. 1986

Thomas A. Commes *(51)* President and Chief Operating Officer of The Sherwin-Williams Company, a manufacturer of paints and painting supplies. 1987

Wayne R. Embry *(56)* Executive Vice President and General Manager of the Cleveland Cavaliers, a professional basketball team. Chairman of Michael Alan Lewis Company, a fabricator of hardboard, fiberglass and carpeting materials for the automotive industry. 1991

Robert J. Farling *(57)* Chairman, President and Chief Executive Officer of the Company and Centerior Service Company. 1988

Number in parenthesis indicates age.
Date indicates first year in which elected to Board.

George H. Kaull *(62)* Retired Chairman of Premix, Inc., a developer, manufacturer and fabricator of thermoset reinforced composite materials. 1987

Richard A. Miller *(67)* Retired Chairman and Chief Executive Officer of the Company and Centerior Service Company. 1986

Frank E. Mosier *(63)* Retired Vice Chairman of the Advisory Board of BP America Inc., a producer and refiner of petroleum products. 1986

Sister Mary Marthe Reinhard, SND *(64)* Director of Development for the Sisters of Notre Dame of Cleveland, Ohio. Former President of Notre Dame College of Ohio. 1986

Robert C. Savage *(56)* President and Chief Executive Officer of Savage & Associates, Inc., an insurance, financial planning and estate planning firm. 1990

Paul M. Smart* *(65)* Attorney and retired Vice Chairman of the Company and The Toledo Edison Company. 1986

William J. Williams *(65)* Retired Chairman of Huntington National Bank. 1986

Robert M. Ginn Chairman Emeritus
John P. Williamson Chairman Emeritus

(*) Retired from the Board on January 31, 1994.

COMMITTEES OF THE BOARD

Audit	*Capital Expenditures*	*Environmental and Community Responsibility*	*Executive and Nominating*	*Finance*	*Human Resources*	*Nuclear*
T.A. Commes, Chairman	G.H. Kaull, Chairman	Sr. M.M. Reinhard, Chairman	R.J. Farling, Chairman	R.A. Miller, Chairman	F.E. Mosier, Chairman	R.P. Anderson, Chairman
R.P. Anderson	A.C. Bersticker	W.R. Embry	L. Carter	L. Carter	W.R. Embry	A.C. Bersticker
L. Carter	R.A. Miller	R.A. Miller	T.A. Commes	T.A. Commes	G.H. Kaull	R.J. Farling
W.R. Embry	F.E. Mosier	F.E. Mosier	R.A. Miller	R.J. Farling	R.C. Savage	Sr. M.M. Reinhard
Sr. M.M. Reinhard	P.M. Smart*	P.M. Smart*	W.J. Williams	F.E. Mosier	W.J. Williams	W.J. Williams
				R.C. Savage		
				P.M. Smart*		

(*) Retired from the Board on January 31, 1994.

	Electric Sales (millions of KWH)						Electric Customers (year end)				Residential Usage		
Year	Residential	Commercial	Industrial	Wholesale	Other	Total	Residential	Commercial	Industrial & Other	Total	Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
1993	6 974	7 306	11 687	3 027	1 022	30 016	924 227	96 491	12 219	1 032 937	7 546	11.01¢	$830.99
1992	6 666	7 086	11 551	2 814	1 011	29 128	925 099	96 813	12 741	1 034 653	7 227	10.98	793.68
1991	6 981	7 176	11 559	2 690	1 048	29 454	921 995	96 449	12 843	1 031 287	7 410	11.16	827.10
1990	6 666	6 848	12 168	2 487	959	29 128	918 965	94 522	12 906	1 026 393	7 079	10.82	765.93
1989	6 806	6 830	12 520	3 235	996	30 387	914 020	93 833	12 763	1 020 616	7 295	10.08	737.58
1983	6 327	5 606	10 641	703	854	24 131	886 024	85 769	11 557	983 350	6 967	8.64	603.22

	Load (MW & %)				Energy (millions of KWH)					Fuel	
					Company Generated						
Year	Operable Capacity at Time of Peak	Peak Load	Capacity Margin	Load Factor	Fossil	Nuclear	Total	Purchased Power	Total	Fuel Cost Per KWH	Efficiency—BTU Per KWH
1993	5 998	5 397	10.0%	61.6%	21 105	10 435	31 540	273	31 813	1.39¢	10 276
1992	6 430	5 091	20.8	63.4	17 371	13 814	31 185	(122)	31 063	1.45	10 395
1991	6 453	5 361	16.9	62.9	18 041	13 454	31 495	40	31 535	1.48	10 442
1990	6 437	5 261	18.3	63.6	21 114	9 481	30 595	413	31 008	1.52	10 354
1989	6 430	5 389	16.2	63.3	20 174	12 122	32 296	21	32 317	1.47	10 435
1983	6 218	4 717	24.1	63.1	19 487	4 895	24 382	1 650	26 032	1.72	10 419

Investment (millions of dollars)

Year	Utility Plant In Service	Accumulated Depreciation & Amortization	Net Plant	Construction Work In Progress & Perry Unit 2	Nuclear Fuel and Other	Total Property, Plant and Equipment	Utility Plant Additions	Total Assets
1993	$9 571	2 677	6 894	181	385	$7 460	$218	$10 710
1992	9 449	2 488	6 961	781	424	8 166	200	12 071
1991	8 888	2 274	6 614	853	503	7 970	204	11 829
1990	8 636	2 039	6 597	921	568	8 086	251	11 681
1989	8 398	1 824	6 574	945	592	8 111	217	11 454
1983	4 180	1 047	3 133	2 710	392(f)	6 235	785	6 922

Capitalization (millions of dollars & %)

Year	Common Stock Equity		Preferred & Preference Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
1993	$1 785	27%	313	5%	451	7%	4 019	61%	$6 568
1992	2 889	39	364	5	354	5	3 694	51	7 301
1991	2 855	38	332	4	427	6	3 841	52	7 455
1990	2 810	39	237	3	427	6	3 729	52	7 203
1989	2 795	40	281	4	427	6	3 534	50	7 037
1983	2 065	39	412	8	344	6	2 504	47	5 325

(d) Includes write-off of Perry Unit 2 of $583 million in 1993.

(e) Average shares outstanding and related per share computations reflect the Cleveland Electric 1.11-for-one exchange ratio and the Toledo Edison one-for-one exchange ratio for Centerior Energy shares at the date of affiliation, April 29, 1986.

(f) Restated for effects of capitalization of nuclear fuel lease and financing arrangements pursuant to Statement of Financial Accounting Standards 71.

Dividend Reinvestment and Stock Purchase Plan and Individual Retirement Account (CX•IRA)

The Company has a Dividend Reinvestment and Stock Purchase Plan which provides share owners of record and customers of the Company's subsidiaries a convenient means of purchasing shares of Company common stock by investing all or a part of their quarterly dividends as well as making cash investments. In addition, individuals may establish an individual retirement account (IRA) which invests in Company common stock through the Plan. Information relating to the Plan and the CX•IRA may be obtained from Share Owner Services at the Company.

CX•IRA Custodian

All communications about an existing CX•IRA should be directed to the Custodian at the address or telephone numbers listed below:

Society National Bank
Custodian, CX•IRA
P.O. Box 6477
Cleveland, OH 44101

In Cleveland area 737-5745

Elsewhere in Ohio 1-800-362-0697, Extension 5745

Outside Ohio 1-800-321-1355, Extension 5745

Share Owner Services

Communications regarding stock transfer requirements, lost certificates, dividends and changes of address should be directed to Share Owner Services at the Company. To reach Share Owner Services by phone, call:

In Cleveland area 642-6900 or 447-2400

Outside Cleveland area 1-800-433-7794

Please have your account number ready when calling.

Investor Relations

Inquiries from security analysts and institutional investors should be directed to Terrence R. Moran, Manager-Investor Relations, at the Company's mail address or by telephone at (216) 447-2882.

Transfer Agent

Centerior Energy Corporation
Share Owner Services
P.O. Box 94661
Cleveland, OH 44101-4661

Stock transfers may be presented at
Society Trust Company of New York
5 Hanover Square, 10th Floor
New York, NY 10004

Registrar

Society National Bank
Corporate Trust Division
P.O. Box 6477
Cleveland, OH 44101

Executive Offices

Centerior Energy Corporation
6200 Oak Tree Boulevard
Independence, OH
Telephone: (216) 447-3100
FAX: (216) 447-3240

Mail Address

Centerior Energy Corporation
P.O. Box 94661
Cleveland, OH 44101-4661

Independent Accountants

Arthur Andersen & Co.
1717 East Ninth Street
Cleveland, OH 44114

Common Stock

Listed on the New York, Midwest and Pacific Stock Exchanges. Options are traded on The Pacific Stock Exchange. New York Stock Exchange symbol–CX. Newspaper abbreviation–CentEn or CentrEngy.

Annual Meeting

The 1994 annual meeting of the share owners of the Company will be held on April 26, 1994. Owners of common stock as of February 25, 1994, the record date for the meeting, will be eligible to vote on matters brought up for share owners' consideration.

Environmental Report

The Company will furnish to share owners, without charge, a copy of a report on its environmental performance. Requests should be directed to Share Owner Services.

Form 10-K

The Company will furnish to share owners, without charge, a copy of its most recent annual report to the Securities and Exchange Commission. Requests should be directed to Share Owner Services.

Audio Cassettes

Share owners with impaired vision may obtain audio cassettes of the Company's Quarterly Reports and Annual Report. To obtain a cassette, simply write or call Share Owner Services. There is no charge for this service.

Centerior Energy Corporation
P.O. Box 94661
Cleveland, OH 44101-4661