The Toledo Edison Company

A subsidiary of Centerior Energy

ANNUAL REPORT
1995

Contents

About Toledo Edison

The Company, a wholly owned subsidiary of Centerior Energy Corporation, provides electric service to a 2,500-square mile area of northwestern Ohio. The Company also provides electric energy at wholesale to 13 municipally owned distribution systems and one rural electric cooperative distribution system in its service area. Although the principal city in its service area is Toledo, the Company derives about 54% of its total electric retail revenues from customers outside of the city. The Company's 1,809 employees serve about 290,000 customers.

Executive Offices

The Toledo Edison Company
300 Madison Avenue
Toledo, OH 43652-0001
(419) 249-5000

General information about the Company and Centerior Energy Corporation is available on the Internet at
http: // www.centerior.com

Printed on recycled paper

Directors

Robert J. Farling, Chairman and Chief Executive Officer of the Company and The Cleveland Electric Illuminating Company and Chairman, President and Chief Executive Officer of Centerior Energy Corporation and Centerior Service Company.

Murray R. Edelman, Vice Chairman of the Company, President of The Cleveland Electric Illuminating Company and Executive Vice President of Centerior Energy Corporation and Centerior Service Company.

Fred J. Lange, Jr., President of the Company, Vice President of The Cleveland Electric Illuminating Company and Senior Vice President of Centerior Energy Corporation and Centerior Service Company.

Officers

Chairman and Chief Executive Officer	*Robert J. Farling*
Vice Chairman	*Murray R. Edelman*
President	*Fred J. Lange, Jr.*
Vice President & Chief Financial Officer	*Terrence G. Linnert*
Vice President	*Gary R. Leidich*
Regional Vice President – West	*John E. Paganie*
Treasurer	*David M. Blank*
Controller	*E. Lyle Pepin*
Secretary	*Janis T. Percio*

Management's Financial Analysis

Outlook

Strategic Plan

We continued to make progress during the second year of our eight-year strategic plan, but we remain keenly aware of the magnitude of the problems that face us. The strategic plan was created by Centerior Energy Corporation (Centerior Energy), along with The Toledo Edison Company (Company) and The Cleveland Electric Illuminating Company (Cleveland Electric), to achieve two major goals: strengthening their financial conditions and improving their competitive positions. The Company and Cleveland Electric are the two wholly owned electric utility subsidiaries of Centerior Energy. The plan's objectives relate to the combined operations of all three companies. The objectives are to achieve profitable revenue growth, become a leader in customer satisfaction, build a winning employee team, attain increasingly competitive power supply costs and maximize share owner return on Centerior Energy common stock. We are not yet positioned to compete in a less regulated electric utility industry, but every major action being taken — strategic planning, revenue enhancement, cost reduction, improvement of work practices and application for increased prices — is part of a comprehensive effort to succeed in an increasingly competitive environment.

A primary objective of the strategic plan is continued and significant revenue growth even as our markets become more competitive. The Company's retail revenues adjusted for weather and fuel costs have grown about 1% annually since 1990. During 1995, we took aggressive steps to increase revenues through enhanced marketing strategies. Also, our economic development efforts proved successful in attracting major new customers and supporting the expansion of existing ones. Although we are not satisfied with our growth rate, we expect that our marketing activity will improve revenue growth.

The rate case which the Company and Cleveland Electric filed with The Public Utilities Commission of Ohio (PUCO) in April 1995 is a critical factor to the success of the strategic plan. We do not see this rate case as a continuation of business as usual but as an important turning point which should, if we are successful in accomplishing the objectives discussed below, bring an end to price increases for the foreseeable future. A successful conclusion of the case would speed our transition to a more competitive company by providing additional cash to lower costs by accelerating the pay-down of debt and preferred stock. In our view, a successful conclusion would include approval of the full price increase requested with a regulatory commitment to maintain the established price levels over an appropriate transition period. This should be coupled with a means to accelerate recognition of regulatory assets (described in Note 7(a)) and nuclear generating assets concurrent with our cost control and revenue enhancement efforts in order to earn a fair return for Centerior Energy common stock share owners over time.

Another key part of our strategy is offering long-term contracts to those large customers who could have incentives to change power suppliers. In 1995, 74% of our industrial kilowatt-hour sales and 13% of our commercial kilowatt-hour sales were under long-term contracts. We are renegotiating contracts before they expire and in most cases are retaining customers under new long-term contracts.

We are continuing efforts to reduce fixed financing costs in order to strengthen our financial condition. During 1995, utilizing strong cash flow and refinancing at favorable terms, the Company reduced interest expense and preferred dividends by $7 million and outstanding debt and preferred stock by $113 million.

Our overall costs are high relative to many of our neighboring utilities as a result of our substantial nuclear investment. The strategic plan calls for making us more competitive by continuing to reduce operating expenses and capital expenditures. In 1995, to improve the focus on cost reduction and other strategic plan objectives, Centerior Energy and its subsidiaries restructured into six business groups. The new organization includes groups to manage the generation, distribution and transmission businesses; provide services and administrative functions; and invest in nonregulated enterprises. This arrangement will also enhance each group's ability to identify cost reductions by focusing on margins and improving work practices and customer service. We will also continue to aggressively pursue initiatives to reduce the heavy tax burden imposed upon us by the state and local tax structure in Ohio.

Rate Case and Regulatory Accounting

In April 1995, the Company and Cleveland Electric filed requests with the PUCO for price increases aggregating $119 million annually to be effective in 1996. The price increases are necessary to recover cost increases and amortization of certain costs deferred since 1992 pursuant to the Rate Stabilization Program discussed below and in

Note 7. If their requests are approved, the Company and Cleveland Electric intend to freeze prices until at least 2002 with the expectation that increased sales and cost control measures will obviate the need for further price increases. If circumstances make it impossible to earn a fair return for Centerior Energy common stock share owners over time, the Company and Cleveland Electric would ask for a further increase — but only after taking all appropriate actions to make such a request unnecessary.

In December 1995, the PUCO ordered an investigation into the financial conditions, rates and practices of the Company and Cleveland Electric.

In its report on the rate request, the PUCO Staff recommended approval of the $119 million requested ($35 million for the Company and $84 million for Cleveland Electric), subject to a commitment by the Company and Cleveland Electric to significantly revalue their assets. In late January 1996, the Staff proposed that the Company and Cleveland Electric significantly revalue their nuclear plant and regulatory assets within a five-year period. The Staff's asset revaluation proposal is inconsistent with the Ohio statutes that define the rate-making process. The PUCO is not bound by the Staff's recommendations. A decision by the PUCO is anticipated in the second quarter of 1996.

The outcome of the rate case could affect the Company's ability to meet the criteria of Statement of Financial Accounting Standards (SFAS) 71 for all or part of its operations which could result in the write-off of all or a part of the regulatory assets shown in Note 7(a). In our changing industry, other events independent of the outcome of the rate case could also result in write-offs or write-downs of assets.

See Note 7 for a full discussion and analysis of the rate case, SFAS 71 and other financial accounting requirements and the potential implications of these accounting requirements for the Company's results of operations and financial position.

Rate Stabilization Program

Under a Rate Stabilization Program approved by the PUCO in 1992, we agreed to freeze base rates until 1996 and limit rate increases through 1998. In exchange, we were permitted to defer through 1995 and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. Deferral of those costs and amortization of those benefits were completed in November 1995 and aggregated $56 million for the Company in 1995. Recovery is expected to begin with the effective date of the PUCO's order in the pending rate case. Annual amortization of the deferred costs for the Company is $10 million which began in December 1995. Consequently, earnings in 1996 will be sharply lower than in 1995. Also contributing to lower earnings are the expectations that the requested price increase will not be effective until the second quarter of 1996 and results from increased marketing and cost reduction efforts will take time to achieve.

Competition

Major structural changes are taking place in the electric utility industry which are expected to place downward pressure on prices and to increase competition for customers' business. The changes are coming from both federal and state authorities. Many of the changes began when the Energy Policy Act of 1992 permitted competition in the electric utility industry through broader access to a utility's transmission system. In March 1995, the Federal Energy Regulatory Commission (FERC) issued proposed rules relating to open access transmission services by public utilities, recovery of stranded investment and other related matters. The open access transmission rules require utilities to deliver power from other utilities or generation sources to their wholesale customers. In May 1995, the Company and Cleveland Electric filed open access transmission tariffs with the FERC which used the proposed rules as a guideline. These tariffs are currently pending.

Several groups in Ohio are studying the possible application of retail wheeling. Retail wheeling occurs when a customer obtains power from a utility company other than its local utility. The PUCO is sponsoring informal discussions among a group of business, utility and consumer interests to explore ways of promoting competitive options without unduly harming the interests of utility company share owners or customers. Legislative proposals are being drafted for submission to the Ohio House of Representatives and several utilities in the state have offered their own proposed transition plans for introduction of retail wheeling. The current retail wheeling efforts in Ohio are exploratory and we cannot predict when and to what extent retail wheeling will be implemented in Ohio.

The term "stranded investment" generally refers to fixed costs approved for recovery under traditional regulatory methods that would become unrecoverable, or "stranded", as a result of wider competition. Although

competitive pressures are increasing, the traditional regulatory framework remains in place and is expected to continue for the foreseeable future. We cannot predict when and to what extent competition will be allowed. We believe that pure competition (unrestricted retail wheeling for all customer classifications) is at least several years away and that any transition to pure competition will be in phases. The FERC and the PUCO have acknowledged the need to provide at least partial recovery of stranded investment as greater competition is permitted and, therefore, we believe that there will be a mechanism developed for the recovery of stranded investment. However, due to the uncertainty involved, there is a risk that some of our assets may not be fully recovered.

In 1995, we continued to experience significant competition from municipal electric systems. Also, in Toledo, the City Council responded to a petition drive by appropriating funds to complete a consultant's study on whether to create a municipal electric utility. This study is expected to be completed by mid-1996.

In October 1995, Chase Brass & Copper Co. Inc., which has provided annual net income of $2 million, terminated its service from the Company and began to receive its electric service from a consortium of other providers. We have filed lawsuits contending that this arrangement violates the legal limits of sales and delivery of power by municipal electric systems outside their boundaries. We will continue to pursue all legal and regulatory remedies to this situation.

In 1995, our economic development efforts proved successful in attracting major new customers, such as North Star BHP Steel, Worthington Steel and Aluminum Company of America, while supporting the expansion of existing ones. We expect that our continued emphasis on economic development along with a newly developed market segment focus will be major ingredients in providing improved revenue growth.

Nuclear Operations

The Company has interests in three nuclear generating units — Davis-Besse Nuclear Power Station (Davis-Besse), Perry Nuclear Power Plant Unit 1 (Perry Unit 1) and Beaver Valley Power Station Unit 2 (Beaver Valley Unit 2) — and operates the first one. Cleveland Electric operates Perry Unit 1. Davis-Besse and Beaver Valley Unit 2 both operated extremely well in 1995. Their average three-year unit availability factors at year-end 1995 of 90% and 87%, respectively, exceeded the industry average of 81% for similar reactors. In 1995, the availability factor for Davis-Besse was 100%. The plant continues to have its best run ever operating at or near full capacity for 463 straight days through February 21, 1996.

In 1995, Perry Unit 1 improved its average three-year unit availability factor to 62% with a 1995 availability factor of 93%. Perry Unit 1 operated at or near capacity for 506 of 531 days since the end of its last refueling and maintenance outage in August 1994. Work on the comprehensive course of action plan developed in 1993 for Cleveland Electric to improve the operating performance of Perry Unit 1 will be completed during the current refueling outage which began January 27, 1996.

A significant part of the strategic plan involves ongoing efforts to increase the availability and lower the cost of production of our nuclear units. In 1995, we made great progress regarding unit availability while continuing to lower production costs. The goal of our nuclear improvement program is for Cleveland Electric to replicate Davis-Besse's operational excellence and cost reduction gains at Perry Unit 1 while improving performance ratings.

We externally fund the estimated costs for the future decommissioning of our nuclear units. In 1993 and 1994, we increased our decommissioning expense accruals because of revisions in our cost estimates. See Note 1(e).

Our nuclear units may be impacted by activities or events beyond our control. Operating nuclear 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 domestic nuclear unit. If one of our nuclear units is taken out of service for an extended period 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, thereby not permitting us to recover our investment in and earn a return on it, or disallowing certain construction or maintenance costs. An extended outage coupled with unfavorable rate treatment could have a material adverse effect on our financial condition and results of operations. Premature plant closings could also have a material adverse effect on our financial condition and results of operations because the estimated cost to decommission the plant exceeds the current funding in the decommissioning trust.

Hazardous Waste Disposal Sites

The Company is aware of its potential involvement in the cleanup of several sites. Although these sites are not on the Superfund National Priorities List, they are generally being administered by various governmental entities in the same manner as they would be administered if they were on such list. Allegations that the Company disposed of hazardous waste at these sites, and the amount involved, are often unsubstantiated and subject to dispute. Federal law provides that all "potentially responsible parties" (PRPs) for a particular site be held liable on a joint and several basis. If the Company were held liable for 100% of the cleanup costs of all of the sites referred to above, the cost could be as high as $150 million. However, we believe that the actual cleanup costs will be substantially lower than $150 million, that the Company's 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 Company has accrued a liability totaling $5 million at December 31, 1995, based on estimates of the costs of cleanup and its 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.

Common Stock Dividends

In recent years, the Company has retained all of its earnings available for common stock. The Company has not paid a common stock dividend to Centerior Energy since February 1991. The Company is currently prohibited from paying a common stock dividend by a provision in its mortgage. See Note 11(b). The Company does not expect to pay any common stock dividends prior to its merger into Cleveland Electric, as discussed below.

Merger of the Company into Cleveland Electric

We continue to seek the necessary regulatory approvals to complete the merger of the Company into Cleveland Electric which was announced in 1994. The FERC has deferred action on the merger application until the merits of the open access transmission tariffs proposed by the Company and Cleveland Electric are addressed in hearings. See Note 15.

Capital Resources and Liquidity

1993-1995 Cash Requirements

A key part of the strategic plan is to significantly reduce the Company's level of debt and preferred stock. In 1995, we were able to continue the reduction pattern begun in 1994. The Company's obligations were reduced by $66 million in 1994 and by $113 million in 1995. We intend to continue and to accelerate redemptions.

We need cash for normal corporate operations, retirement of maturing securities, and an ongoing program of constructing and improving facilities to meet demand for electric service and to comply with government regulations. Our cash construction expenditures totaled $42 million in 1993, $41 million in 1994 and $53 million in 1995. Our debt and preferred stock maturities and sinking fund requirements totaled $58 million in both 1993 and 1994 and $83 million in 1995. In addition, we optionally redeemed approximately $200 million in the period 1993-1995. This amount includes $94 million of tax-exempt issues refunded in 1995 resulting in approximately $4 million of interest savings. The embedded cost of the Company's debt at the end of 1995 was 9.23% versus 9.48% in 1994 and 9.59% in 1993. In 1995, the Company and Cleveland Electric renewed for a four-year term approximately $225 million in bank letters of credit supporting the equity owner participants in the Beaver Valley Unit 2 lease. See Note 11(d).

The Company also utilized short-term borrowings to help meet its cash needs. The Company had $21 million of notes payable to affiliates at December 31, 1995. See Note 12.

1996 and Beyond Cash Requirements

The Company's 1996 cash requirements for construction are $74 million and for debt and preferred stock maturities and sinking fund requirements are $58 million. We expect to meet these requirements with internal cash generation, cash reserves and about $40 million from the sale of a AAA-rated security backed by our accounts receivable.

We expect to meet all of our 1997-2000 cash requirements with internal cash generation. Estimated cash requirements for the Company's construction program during this period total $262 million. Debt and preferred stock maturities and sinking fund requirements total $233 million for the same period. If economical, additional securities may be redeemed under optional redemption

provisions, with funding expected to be provided through internal cash generation.

Liquidity

Additional first mortgage bonds may be issued by the Company under its mortgage on the basis of property additions, cash or refundable first mortgage bonds. If the applicable interest coverage test is met, the Company may issue first mortgage bonds on the basis of property additions and, under certain circumstances, refundable bonds. At December 31, 1995, the Company would have been permitted to issue approximately $288 million of additional first mortgage bonds.

The Company also is able to raise funds through the sale of debt and preferred and preference stock. Under its articles of incorporation, the Company cannot issue preferred stock unless certain earnings coverage requirements are met. At December 31, 1995 the Company would have been permitted to issue approximately $158 million of additional preferred stock at an assumed dividend rate of 10.5%. There are no restrictions on the Company's ability to issue preference stock.

The Company and Cleveland Electric have $307 million in financing vehicles available to support their nuclear fuel leases, portions of which mature this year. See Note 6. The Company is a party to a $125 million revolving credit facility which is expected to be renewed when it matures in May 1996. See Note 12. At the end of 1995, the Company had $94 million in cash and temporary investments.

The foregoing financing resources are expected to be sufficient for the Company's needs over the next several years. However, the availability and cost of capital to meet the Company's external financing needs also depend upon such factors as financial market conditions and its credit ratings. Current credit ratings for the Company are as follows:

	Standard & Poor's Corporation	Moody's Investors Service, Inc.
First mortgage bonds	BB	Ba2
Subordinated debt	B+	B1
Preferred stock	B	b2

Results of Operations

1995 vs. 1994

Factors contributing to the 1% increase in 1995 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$ 29
Wholesale Revenues	(9)
Fuel Cost Recovery Revenues	(10)
Miscellaneous Revenues	(1)
Total	$ 9

For the second year in a row, total kilowatt-hour sales increased. Total sales increased 2.2% in 1995 primarily because of the hot summer weather. Residential and commercial sales increased 5.2% and 2.2%, respectively, which included about 1% nonweather-related growth in residential sales. Industrial sales increased 1.8% on the strength of increased sales to large glass manufacturers and the broad-based, smaller industrial customer group. Other sales increased 0.5%. Weather accounted for approximately $13 million of the $21 million increase in 1995 base rate (nonfuel) revenues. Wholesale revenues decreased because of the lower revenues associated with the Beaver Valley Unit 2 capacity sale to Cleveland Electric. See Note 2. Lower 1995 fuel costs recovery revenues resulted from favorable changes in the fuel cost factors. The weighted average of these fuel cost factors decreased approximately 6%.

For 1995, operating revenues were 27% residential, 21% commercial, 29% industrial and 23% other and kilowatt-hour sales were 19% residential, 16% commercial, 37% industrial and 28% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.11 and $.06, respectively.

Operating expenses increased 0.1% in 1995. Federal income taxes increased as a result of higher pretax operating income. Fuel and purchased power expenses decreased because of lower purchased power requirements resulting from the increased availability of the nuclear generating units in 1995.

Interest charges and preferred dividends decreased in 1995 because of the redemption of securities and refinancing at favorable terms.

1994 vs. 1993

Factors contributing to the 0.7% decrease in 1994 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$ 8
Wholesale Revenues	(5)
Fuel Cost Recovery Revenues	(9)
Total	$(6)

The Company experienced good retail kilowatt-hour sales growth in the industrial and commercial categories in 1994; the sales growth for the residential category was lessened by weather conditions, particularly during the summer. The revenue decrease resulted from milder weather conditions in 1994 and both lower wholesale and fuel cost recovery revenues. Weather reduced base rate revenues approximately $7 million from the 1993 amount. Total sales increased 7.8%. Industrial sales increased 8.6% on the strength of increased sales to large automotive manufacturers and the broad-based, smaller industrial customer group. This growth substantiated an economic resurgence in Northwestern Ohio. Residential and commercial sales increased 0.8% and 2.3%, respectively. Other sales increased 16% because of increased sales to wholesale customers, although the softer wholesale market conditions in 1994 resulted in lower wholesale revenues. Lower 1994 fuel cost recovery revenues resulted from favorable changes in the fuel cost factors. The weighted average of these fuel cost factors dropped by 6%.

For 1994, operating revenues were 26% residential, 21% commercial, 29% industrial and 24% other and kilowatt-hour sales were 19% residential, 16% commercial, 37% industrial and 28% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.11 and $.06, respectively. The changes from 1993 were not significant.

Operating expenses were 12% lower in 1994. Operation and maintenance expenses for 1993 included $88 million of net benefit expenses related to an early retirement program, called the Voluntary Transition Program (VTP), and other charges totaling $19 million. The VTP benefit expenses in 1993 consisted of $75 million of costs for the Company plus $13 million for the Company's pro rata share of the costs for its affiliate, Centerior Service Company (Service Company). A smaller work force and ongoing cost reduction measures also lowered operation and maintenance expenses. Lower purchased power costs helped reduce fuel and purchased power expenses in 1994 despite an increase in the amount of power purchased. More nuclear generation and less coal-fired generation also accounted for a part of the lower fuel and purchased power expenses. Depreciation and amortization expenses increased primarily because of higher nuclear plant decommissioning expenses as discussed in Note 1(e). Deferred operating expenses were greater primarily because of the write-off of $55 million of phase-in deferred operating expenses in 1993 as discussed in Note 7(e). The 1993 deferrals also included $32 million of postretirement benefit curtailment cost deferrals related to the VTP. See Note 9(b). Federal income taxes increased as a result of higher pretax operating income.

As discussed in Note 4(b), $232 million of our Perry Unit 2 investment was written off in 1993. Also, as discussed in Note 7(e), phase-in deferred carrying charges of $186 million were written off in 1993. The change in the federal income tax credit amounts for nonoperating income was attributable to these write-offs.

Income Statement

The Toledo Edison Company

	For the years ended December 31,		
	1995	1994	1993
		(millions of dollars)	
Operating Revenues (1)	$874	$865	$ 871
Operating Expenses			
Fuel and purchased power	157	167	173
Other operation and maintenance	225	229	245
Generation facilities rental expense, net	104	104	104
Early retirement program expenses and other	—	—	107
Total operation and maintenance	486	500	629
Depreciation and amortization	84	83	76
Taxes, other than federal income taxes	91	90	91
Deferred operating expenses, net	(17)	(21)	(4)
Federal income taxes (credit)	42	33	(10)
	686	685	782
Operating Income	188	180	89
Nonoperating Income (Loss)			
Allowance for equity funds used during construction	1	1	1
Other income and deductions, net	6	3	—
Write-off of Perry Unit 2	—	—	(232)
Deferred carrying charges, net	14	15	(161)
Federal income taxes — credit (expense)	(2)	(2)	129
	19	17	(263)
Income (Loss) Before Interest Charges	207	197	(174)
Interest Charges			
Debt interest	111	116	116
Allowance for borrowed funds used during construction	(1)	(1)	(1)
	110	115	115
Net Income (Loss)	97	82	(289)
Preferred Dividend Requirements	18	20	23
Earnings (Loss) Available for Common Stock	$ 79	$ 62	$(312)

(1) Includes revenues from all bulk power sales to Cleveland Electric of $102 million, $111 million and $120 million in 1995, 1994 and 1993, respectively.

Retained Earnings

	For the years ended December 31,		
	1995	1994	1993
		(millions of dollars)	
Retained Earnings (Deficit) at Beginning of Year	$(113)	$(175)	$ 137
Additions			
Net income (loss)	97	82	(289)
Deductions			
Preferred stock dividends declared and other	(19)	(20)	(23)
Net Increase (Decrease)	78	62	(312)
Retained Earnings (Deficit) at End of Year	$ (35)	$(113)	$(175)

The accompanying notes are an integral part of these statements.

Balance Sheet

	December 31, 1995	December 31, 1994
	(millions of dollars)	
ASSETS		
Property, Plant and Equipment		
Utility plant in service	$2,896	$2,899
Less: accumulated depreciation and amortization	942	892
	1,954	2,007
Construction work in progress	28	30
	1,982	2,037
Nuclear fuel, net of amortization	78	119
Other property, less accumulated depreciation	20	6
	2,080	2,162
Current Assets		
Cash and temporary cash investments	94	88
Amounts due from customers and others, net	68	62
Amounts due from affiliates	19	19
Unbilled revenues	22	22
Materials and supplies, at average cost	40	45
Fossil fuel inventory, at average cost	9	12
Taxes applicable to succeeding years	71	72
Other	4	2
	327	322
Regulatory and Other Assets		
Amounts due from customers for future federal income taxes, net	416	405
Unamortized loss from Beaver Valley Unit 2 sale	96	101
Unamortized loss on reacquired debt	28	28
Carrying charges and operating expenses	410	379
Nuclear plant decommissioning trusts	52	38
Other	65	67
	1,067	1,018
Total Assets	$3,474	$3,502

The accompanying notes are an integral part of this statement.

CAPITALIZATION AND LIABILITIES

	December 31, 1995	December 31, 1994
	(millions of dollars)	
Capitalization		
Common shares, \$5 par value: 60 million authorized; 39.1 million outstanding in 1995 and 1994	\$ 196	\$ 196
Premium on capital stock	481	481
Other paid-in capital	121	121
Retained earnings (deficit)	(35)	(113)
Common stock equity	763	685
Preferred stock		
With mandatory redemption provisions	5	7
Without mandatory redemption provisions	210	210
Long-term debt	1,068	1,154
	2,046	2,056
Current Liabilities		
Current portion of long-term debt and preferred stock	58	83
Current portion of nuclear fuel lease obligations	40	36
Accounts payable	56	48
Accounts and notes payable to affiliates	53	31
Accrued taxes	78	75
Accrued interest	24	27
Other	20	16
	329	316
Deferred Credits and Other Liabilities		
Unamortized investment tax credits	79	87
Accumulated deferred federal income taxes	573	541
Unamortized gain from Bruce Mansfield Plant sale	188	198
Accumulated deferred rents for Bruce Mansfield Plant and Beaver Valley Unit 2	54	54
Nuclear fuel lease obligations	52	87
Retirement benefits	103	103
Other	50	60
	1,099	1,130
Total Capitalization and Liabilities	\$3,474	\$3,502

Cash Flows

	For the years ended December 31,		
	1995	1994	1993
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income (Loss)	$ 97	$ 82	$(289)
Adjustments to Reconcile Net Income (Loss) to Cash from Operating Activities:			
Depreciation and amortization	84	83	76
Deferred federal income taxes	16	46	(160)
Unbilled revenues	—	3	(4)
Deferred fuel	(3)	3	—
Deferred carrying charges, net	(14)	(15)	161
Leased nuclear fuel amortization	54	44	38
Deferred operating expenses, net	(17)	(21)	(4)
Allowance for equity funds used during construction	(1)	(1)	(1)
Noncash early retirement program expenses, net	—	—	83
Write-off of Perry Unit 2	—	—	232
Changes in amounts due from customers and others, net	(6)	1	(3)
Changes in inventories	8	(2)	10
Changes in accounts payable	8	(15)	16
Changes in working capital affecting operations	4	(16)	21
Other noncash items	9	10	14
Total Adjustments	142	120	479
Net Cash from Operating Activities	239	202	190
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	—	—	(40)
Notes payable to affiliates	21	—	—
First mortgage bond issues	99	31	20
Secured medium-term note issues	—	—	93
Maturities, redemptions and sinking funds	(215)	(98)	(89)
Nuclear fuel lease obligations	(44)	(49)	(47)
Dividends paid	(18)	(20)	(23)
Premiums, discounts and expenses	(6)	—	(1)
Net Cash from Financing Activities	(163)	(136)	(87)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(53)	(41)	(42)
Interest capitalized as allowance for borrowed funds used during construction	(1)	(1)	(1)
Contributions to nuclear plant decommissioning trusts	(11)	(12)	(4)
Other cash received (applied)	(5)	(6)	10
Net Cash from Investing Activities	(70)	(60)	(37)
Net Change in Cash and Temporary Cash Investments	6	6	66
Cash and Temporary Cash Investments at Beginning of Year	88	82	16
Cash and Temporary Cash Investments at End of Year	$ 94	$ 88	$ 82

(1) Interest paid (net of amounts capitalized)	*$ 93*	*$ 94*	*$ 92*
Income taxes paid	*$ 23*	*$ 5*	*$ 7*

(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

	1995 Shares Outstanding	Current Call Price Per Share	December 31, 1995	December 31, 1994
			(millions of dollars)	
$100 par value, 3,000,000 preferred shares authorized;				
$25 par value, 12,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$100 par $9.375	66,850	$101.48	$ 7	$ 8
25 par 2.81	—	—	—	10
			7	18
Less: Current maturities			2	11
Total Preferred Stock, with Mandatory Redemption Provisions			$ 5	$ 7
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	25.00	30	30
Series B Adjustable	1,200,000	25.75	30	30
Total Preferred Stock, without Mandatory Redemption Provisions			$210	$210

The accompanying notes are an integral part of this statement.

Notes to the Financial Statements

(1) Summary of Significant Accounting Policies

(a) General

The Company is an electric utility and a wholly owned subsidiary of Centerior Energy. The Company follows the Uniform System of Accounts prescribed by the FERC and adopted by the PUCO. Rate-regulated utilities are subject to SFAS 71 which governs accounting for the effects of certain types of rate regulation. Pursuant to SFAS 71, certain incurred costs are deferred for recovery in future rates. See Note 7.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. The estimates are based on an analysis of the best information available. Actual results could differ from those estimates.

The Company is a member of the Central Area Power Coordination Group (CAPCO). Other members are Cleveland Electric, 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 joint use.

(b) Related Party Transactions

Operating revenues, operating expenses and interest charges include those amounts for transactions with affiliated companies in the ordinary course of business operations.

The Company's transactions with Cleveland Electric are primarily for firm power, interchange power, transmission line rentals and jointly owned power plant operations and construction. See Notes 2 and 3.

The Service Company provides management, financial, administrative, engineering, legal and other services at cost to the Company and other affiliated companies. The Service Company billed the Company $67 million, $59 million and $71 million in 1995, 1994 and 1993, respectively, for such services.

(c) 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.

(d) 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 base rates.

The Company defers 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 (to 2007). The Company has accrued a liability for its share of the total assessments. These costs have been recorded in a deferred charge account since the PUCO is allowing the Company to recover the assessments through its fuel cost factors.

(e) Depreciation and Decommissioning

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 nonnuclear property expressed as a percent of average depreciable utility plant in service was 3.8% in 1995, 3.5% in 1994 and 3.6% in 1993. The annual straight-line depreciation rate for nuclear property is 2.5%. In conjunction with its pending rate case, the Company has asked the PUCO to approve an increase of this depreciation rate to approximately 3%.

The Company accrues the estimated costs of decommissioning its three nuclear generating units. The accruals are required to be funded in an external trust. The PUCO requires that the expense and payments to the external trusts be determined on a levelized basis by dividing the unrecovered decommissioning costs in current dollars by the remaining years in the licensing period of each unit. This methodology requires that the net earnings on the

trusts be reinvested therein with the intent of having net earnings offset inflation. The PUCO requires that the estimated costs of decommissioning and the funding level be reviewed at least every five years.

In 1994, the Company increased its annual decommissioning expense accruals to $11 million from the $5 million level in 1993. The accruals are reflected in current rates. The increased accruals in 1994 were derived from updated, site-specific studies for each of the units. The revised estimates reflect the DECON method of decommissioning (prompt decontamination), and the locations and cost characteristics specific to the units, and include costs associated with decontamination, dismantlement and site restoration.

The revised estimates for the units in 1993 and 1992 dollars and in dollars at the time of license expiration, assuming a 4% annual inflation rate, are as follows:

Generating Unit	License Expiration Year	Amount	Future Amount
		(millions of dollars)	
Davis-Besse	2017	$168(1)	$419
Perry Unit 1	2026	100(1)	354
Beaver Valley Unit 2	2027	51(2)	190
Total		$319	$963

(1) Dollar amounts in 1993 dollars.
(2) Dollar amount in 1992 dollars.

The updated estimates reflect substantial increases from the prior PUCO-recognized aggregate estimates of $115 million in 1987 and 1986 dollars.

The classification, Accumulated Depreciation and Amortization, in the Balance Sheet at December 31, 1995 includes $59 million of decommissioning costs previously expensed and the earnings on the external trust 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. The trust earnings are recorded as an increase to the trust assets and the related component of the decommissioning reserve (included in Accumulated Depreciation and Amortization).

The staff of the Securities and Exchange Commission has questioned certain of the current accounting practices of the electric utility industry, including those of the Company, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements. In response to these questions, the Financial Accounting Standards Board (FASB) is reviewing the accounting for removal costs, including decommissioning. If current accounting practices are changed, the annual provision for decommissioning could increase; the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation; and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense. The FASB issued an exposure draft on the subject on February 7, 1996.

(f) Property, Plant and Equipment

Property, plant and equipment are stated at original cost less amounts disallowed by the PUCO. Construction costs include related payroll taxes, retirement benefits, 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 rate was 12.6% in 1995, 9.87% in 1994 and 10.22% in 1993.

Maintenance and repairs for plant and equipment 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 the leases. See Note 7(a). These amortizations and the lease expense amounts are reported in the Income Statement as Generation Facilities Rental Expense, Net.

(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. See Note 7(a). 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.

(l) Federal Income Taxes

The Company uses the liability method of accounting for income taxes in accordance with SFAS 109. See Note 8. 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, the Company must record a liability for its 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. See Note 7(a).

Investment tax credits are deferred and amortized over the lives of the applicable property as a reduction of depreciation expense. See Note 7(d) 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 Company and Cleveland Electric 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. These leases extend through 2017 and are the result of sale and leaseback transactions completed in 1987.

Under these leases, the Company and Cleveland Electric 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 Company and Cleveland Electric have options to buy the interests back at the end of the leases for the fair market value at that time or renew the leases. The leases include conditions for mandatory termination (and possible repurchase of the leasehold interest) for events of default.

As co-lessee with Cleveland Electric, the Company is also obligated for Cleveland Electric's lease payments. If Cleveland Electric is unable to make its payments under the Mansfield Plant leases, the Company would be obligated to make such payments. No such payments have been made on behalf of Cleveland Electric.

Future minimum lease payments under the operating leases at December 31, 1995 are summarized as follows:

Year	For the Company	For Cleveland Electric
	(millions of dollars)	
1996	$ 125	$ 63
1997	102	63
1998	102	63
1999	108	70
2000	111	76
Later Years	1,807	1,245
Total Future Minimum Lease Payments	$2,355	$1,580

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1995, 1994 and 1993 as annual rental expense for the Mansfield Plant leases was $45 million. The amounts recorded in 1995, 1994 and 1993 as annual rental expense for the Beaver Valley Unit 2 lease were $63 million, $64 million and $63 million, respectively. Amounts charged to expense in excess of the lease payments are classified as Accumulated Deferred Rents in the Balance Sheet.

The Company is selling 150 megawatts of its Beaver Valley Unit 2 leased capacity entitlement to Cleveland Electric. Revenues recorded for this transaction were $98 million, $108 million and $103 million in 1995, 1994 and 1993, respectively. We anticipate that this sale will continue indefinitely. The future minimum lease payments through 2017 associated with Beaver Valley Unit 2 aggregate $1.35 billion.

(3) Property Owned with Other Utilities and Investors

The Company owns, as a tenant 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 Company's 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, 1995

includes the following facilities owned by the Company as a tenant in common with other utilities and Lessors:

Generating Unit	Ownership Megawatts (% Share)	Property, Plant and Equipment (Exclusive of Nuclear Fuel)	Accumulated Depreciation
		(millions of dollars)	
Davis-Besse	429 (48.62%)	$ 649	$202
Perry Unit 1	238 (19.91)	1,050	221
Beaver Valley Unit 2 and Common Facilities (Note 2)	13 (1.65)	207	48
Total		$1,906	$471

(4) Construction and Contingencies

(a) Construction Program

The estimated cost of the Company's construction program for the 1996-2000 period is $345 million, including AFUDC of $10 million and excluding nuclear fuel.

The Clean Air Act Amendments of 1990 (Clean Air Act) requires, among other things, significant reductions in the emission of sulfur dioxide and nitrogen oxides by fossil-fueled generating units. Our strategy provides for compliance primarily through greater use of low-sulfur coal at some of our units and the use of emission allowances. Total capital expenditures from 1991 through 1995 in connection with Clean Air Act compliance amounted to $4 million. The plan will require additional capital expenditures over the 1996-2005 period of approximately $41 million for nitrogen oxide control equipment and other plant process modifications. In addition, higher fuel and other operation and maintenance expenses may be incurred.

(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. 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 $232 million ($167 million after taxes) for the Company's 19.91% ownership share of the unit.

(c) Hazardous Waste Disposal Sites

The Company is aware of its potential involvement in the cleanup of several sites. The Company has accrued a liability totaling $5 million at December 31, 1995 based on estimates of the costs of cleanup and its 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

The Company's 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 the discussion of these and other risks in Management's Financial Analysis — Outlook-Nuclear Operations.

(b) Nuclear Insurance

The Price-Anderson Act limits the public 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), the Company's maximum potential assessment under that plan would be $70 million per incident. The assessment is limited to $9 million per year for each nuclear incident. These assessment limits assume the other CAPCO companies contribute their proportionate share of any assessment.

The utility owners and lessees of Davis-Besse, Perry and Beaver Valley also have insurance coverage for damage to property at these sites (including leased fuel and cleanup costs). Coverage amounted to $2.75 billion for each site as of January 1, 1996. Damage to property could exceed the insurance coverage by a substantial amount. If it does, the Company's share of such excess amount could have a material adverse effect on its financial condition and results of operations. In addition, the Company can be assessed a maximum of $19 million under these policies 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.

The Company also has 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 80% 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 Company and Cleveland Electric through leases with a special-purpose corporation. The total amount of financing currently available under these lease arrangements is $307 million ($157 million from intermediate-term notes and $150 million from bank credit arrangements). The intermediate-term notes mature in 1996 and 1997 ($84 million in September 1996 and $73 million in September 1997). The bank credit arrangements terminate in October 1996. The special-purpose corporation plans to obtain alternate financing in 1996 to replace the $234 million of financing expiring in 1996. At December 31, 1995, $93 million of nuclear fuel was financed for the Company. The Company and Cleveland Electric 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 for the Company of $37 million, $21 million and $15 million, respectively, at December 31, 1995. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $2 million in 1995, $4 million in 1994 and $6 million in 1993. The estimated future lease amortization payments for the Company based on projected consumption are $41 million in 1996, $34 million in 1997, $29 million in 1998, $28 million in 1999 and $27 million in 2000.

(7) Regulatory Matters

(a) Regulatory Accounting Requirements and Regulatory Assets

The Company is subject to the provisions of SFAS 71 and has complied with its provisions. SFAS 71 provides, among other things, for the deferral of certain incurred costs that are probable of future recovery in rates. We monitor changes in market and regulatory conditions and consider the effects of such changes in assessing the continuing applicability of SFAS 71. Criteria that could give rise to discontinuation of the application of SFAS 71 include: (1) increasing competition which significantly restricts the Company's ability to charge prices which allow it to recover operating costs, earn a fair return on invested capital and recover the amortization of regulatory assets and (2) a significant change in the manner in which rates are set by the PUCO from cost-based regulation to some other form of regulation. Regulatory assets represent probable future revenues to the Company associated with certain incurred costs, which it will recover from customers through the rate-making process.

Effective January 1, 1996, the Company adopted SFAS 121 which imposes stricter criteria for carrying regulatory assets than SFAS 71 by requiring that such assets be probable of recovery at each balance sheet date. The criteria under SFAS 121 for plant assets require such assets to be written down only if the book value exceeds the projected net future cash flows.

Regulatory assets in the Balance Sheet are as follows:

	December 31,	
	1995	1994
	(millions of dollars)	
Amounts due from customers for future federal income taxes, net	$416	$405
Unamortized loss from Beaver Valley Unit 2 sale	96	101
Unamortized loss on reacquired debt	28	28
Pre-phase-in deferrals*	222	229
Rate Stabilization Program deferrals	188	150
Total	$950	$913

* Represent deferrals of operating expenses and carrying charges for Perry Unit 1 and Beaver Valley Unit 2 in 1987 and 1988 which are being amortized over the lives of the related property.

As of December 31, 1995, customer rates provide for recovery of all the above regulatory assets, except those related to the Rate Stabilization Program discussed below. The remaining recovery periods for all of the regulatory assets listed above range from 16 to 33 years.

(b) Rate Case

In April 1995, the Company and Cleveland Electric filed requests with the PUCO for price increases aggregating $119 million annually to be effective in 1996. The price increases are necessary to recover cost increases and amortization of certain costs deferred since 1992 pursuant to the Rate Stabilization Program. If their requests are approved, the Company and Cleveland Electric intend to freeze prices until at least 2002 with the expectation that increased sales and cost control measures will preclude the need for further price increases. If circumstances make it impossible to earn a fair return for Centerior Energy common stock share owners over time, the Company and Cleveland Electric would ask for a further increase, but only after taking all appropriate actions to make such a request unnecessary.

In November 1995, the PUCO Staff issued its report addressing the rate case. The Staff recommended that the PUCO grant the full $119 million price increase requested ($35 million for the Company and $84 million

for Cleveland Electric). However, the Staff also recommended that the price increase be conditioned upon the commitment by the Company and Cleveland Electric "to a significant revaluation of their asset bases over some finite period of time."

In December 1995, the PUCO ordered an investigation into the financial conditions, rates and practices of the Company and Cleveland Electric to identify outcomes and remedies other than those routinely applied during the rate case process.

In late January 1996, the Staff proposed an incremental reduction (currently, an aggregate of $1.25 billion for the Company and Cleveland Electric) beyond the normal level in nuclear plant and regulatory assets within five years. The Staff proposed that the Company and Cleveland Electric have flexibility to determine how to achieve this incremental asset revaluation, but no additional price increases to recover the accelerated asset revaluation were proposed. Any incremental revaluation of assets would be for regulatory purposes and would cause prices and revenues after the five-year period to be lower than they otherwise would be in conjunction with any rate case following such revaluation. The Staff's asset revaluation proposal represents a substantial change in the form of rate-making traditionally followed by the PUCO and is inconsistent with the Ohio statutes that define the rate-making process. The PUCO is not bound by the recommendations of the Staff. A decision by the PUCO is anticipated in the second quarter of 1996.

(c) Assessment of Potential Outcomes

We continually assess the effects of competition and the changing industry and regulatory environment on operations, the Company's ability to recover regulatory assets and the Company's ability to continue application of SFAS 71. If, as a result of the pending rate case or other events, we determine that the Company no longer meets the criteria for SFAS 71, the Company would be required to record a before-tax charge to write off the regulatory assets shown above and evaluate whether the Company's property, plant and equipment should be written down. In the more likely event that only a portion of operations (such as nuclear operations) no longer meets the criteria of SFAS 71, a write-off would be limited to regulatory assets, if any, that are not reflected in the Company's cost-based prices established for the remaining regulated operations. In addition, we would be required to evaluate whether the changes in the competitive and regulatory environment which led to discontinuing the application of SFAS 71 to a portion of the Company's operations would also result in a write-down of the Company's property, plant and equipment pursuant to SFAS 121.

We believe application of SFAS 121 in that event will not result in a write-off of regulatory assets unless the PUCO denies recovery of such assets or if we conclude, as a result of the outcome of the Company's pending rate case or some other event, that recovery is not probable for some or all of the regulatory assets. Furthermore, a write-down under SFAS 121 of the Company's property, plant and equipment is not expected.

(d) Rate Stabilization Program

The Rate Stabilization Program that the PUCO approved in October 1992 allowed the Company to defer and subsequently amortize and recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits during the 1992-1995 period. Recovery of the deferrals will begin with the effective date of the PUCO's order in the pending rate case. The regulatory assets recorded included the deferral of post-in-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988, the deferral of incremental expenses resulting from the adoption of SFAS 106 (see Note 9(b)), and the deferral of the operating expenses equivalent to an accumulated excess rent reserve for Beaver Valley Unit 2 (which resulted from the April 1992 refinancing of Secured Lease Obligation Bonds issued by a special-purpose corporation). The cost deferrals recorded in 1995, 1994 and 1993 pursuant to these provisions were $38 million, $43 million and $76 million, respectively. The regulatory accounting measures also provided for the accelerated amortization of certain unrestricted excess deferred tax and unrestricted investment tax credit balances and an excess interim spent fuel storage accrual balance for Davis-Besse. The total annual amount of such accelerated benefits was $18 million in 1995, 1994 and 1993.

(e) Phase-in Deferrals

In 1993, upon completing a comprehensive study which led to our strategic plan, we concluded that projected revenues would not provide for recovery of deferrals recorded pursuant to a phase-in plan approved by the PUCO in 1989 and, consequently, that the deferrals would have to be written off. Such deferrals were scheduled to be recovered in 1994 through 1998. The total phase-in deferred operating expenses and carrying charges written off at December 31, 1993 by the Company were $55 million and $186 million, respectively (totaling $165 million after taxes).

(8) Federal Income Tax

The components of federal income tax expense (credit) recorded in the Income Statement were as follows:

	1995	1994	1993
	(millions of dollars)		
Operating Expenses:			
Current	$ 40	$ 18	$ 36
Deferred	2	15	(46)
Total Expense (Credit) to Operating Expenses	42	33	(10)
Nonoperating Income:			
Current	(12)	(29)	(15)
Deferred	14	31	(114)
Total Expense (Credit) to Nonoperating Income	2	2	(129)
Total Federal Income Tax Expense (Credit)	$ 44	$ 35	$(139)

The deferred federal income tax expense results from the temporary differences that arise from the different years certain expenses are recognized for tax purposes as opposed to financial reporting purposes. Such temporary differences affecting operating expenses relate principally to depreciation and deferred operating expenses whereas those affecting nonoperating income principally relate to deferred carrying charges and the 1993 write-offs.

Federal income tax, computed by multiplying income before taxes by the 35% statutory rate, is reconciled to the amount of federal income tax recorded on the books as follows:

	1995	1994	1993
	(millions of dollars)		
Book Income (Loss) Before Federal Income Tax	$141	$117	$(428)
Tax (Credit) on Book Income (Loss) at Statutory Rate	$ 49	$ 41	$(150)
Increase (Decrease) in Tax:			
Write-off of Perry Unit 2	—	—	16
Write-off of phase-in deferrals	—	—	8
Depreciation	(1)	(3)	(12)
Rate Stabilization Program	(9)	(9)	(10)
Sale and leaseback transactions and amortization	5	5	5
Other items	—	1	4
Total Federal Income Tax Expense (Credit)	$ 44	$ 35	$(139)

The Company joins in the filing of a consolidated federal income tax return with its affiliated companies. The method of tax allocation reflects the benefits and burdens realized by each company's participation in the consolidated tax return, approximating a separate return result for each company.

For tax reporting purposes, the Perry Unit 2 abandonment was recognized in 1994 and resulted in a $122 million loss with a corresponding $43 million reduction in federal income tax liability. Because of the alternative minimum tax (AMT), $25 million of the $43 million was realized in 1994. The remaining $18 million will not be realized until 1999.

Under SFAS 109, temporary differences and carryforwards resulted in deferred tax assets of $179 million and deferred tax liabilities of $752 million at December 31, 1995 and deferred tax assets of $178 million and deferred tax liabilities of $719 million at December 31, 1994. These are summarized as follows:

	December 31, 1995	December 31, 1994
	(millions of dollars)	
Property, plant and equipment	$627	$606
Deferred carrying charges and operating expenses	85	83
Net operating loss carryforwards	(44)	(54)
Investment tax credits	(46)	(51)
Sale and leaseback transactions	(4)	(3)
Other	(45)	(40)
Net deferred tax liability	$573	$541

For tax purposes, net operating loss (NOL) carryforwards of approximately $125 million are available to reduce future taxable income and will expire in 2005 through 2009. The 35% tax effect of the NOLs is $44 million. Additionally, AMT credits of $80 million that may be carried forward indefinitely are available to reduce future tax.

(9) Retirement Benefits

(a) Retirement Income Plan

Centerior Energy sponsors jointly with its subsidiaries a noncontributing pension plan (Centerior Pension Plan) which covers all employee groups. The amount of retirement benefits generally depends upon the length of service. Under certain circumstances, benefits can begin as early as age 55. The funding policy is to comply with the Employee Retirement Income Security Act of 1974 guidelines.

In 1993, eligible employees were offered the VTP, an early retirement program. Operating expenses for Centerior Energy and its subsidiaries in 1993 included $205 million of pension plan accruals to cover enhanced VTP benefits offset by a credit of $81 million resulting from a settlement of pension obligations through lump sum payments to almost all the VTP retirees.

Pension and VTP costs (credits) for Centerior Energy and its subsidiaries for 1993 through 1995 were comprised of the following components:

	1995	1994	1993
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 10	$ 13	$ 15
Interest cost on projected benefit obligation	26	26	37
Actual return on plan assets	(53)	(2)	(65)
Net amortization and deferral	9	(34)	4
Net pension costs (credits)	(8)	3	(9)
VTP cost	—	—	205
Settlement gain	—	—	(81)
Net costs (credits)	$ (8)	$ 3	$115

Pension and VTP costs (credits) for the Company and its pro rata share of the Service Company's costs were $(3) million, $1 million and $53 million for 1995, 1994 and 1993, respectively.

The following table presents a reconciliation of the funded status of the Centerior Pension Plan. The Company's share of the Centerior Pension Plan's total projected benefit obligation approximates 30%.

	December 31, 1995	1994
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$304	$278
Nonvested benefits	2	2
Accumulated benefit obligation	306	280
Effect of future compensation levels	54	37
Total projected benefit obligation	360	317
Plan assets at fair market value	394	362
Funded status	34	45
Unrecognized net gain from variance between assumptions and experience	(68)	(79)
Unrecognized prior service cost	15	10
Transition asset at January 1, 1987 being amortized over 19 years	(36)	(39)
Net accrued pension liability	$(55)	$(63)

A September 30 measurement date was used for 1995 and 1994 reporting. At December 31, 1995, the settlement (discount) rate and long-term rate of return on plan assets assumptions were 8% and 11%, respectively. The long-term rate of annual compensation increase assumption was 3.5% in 1996 and 1997 and 4% thereafter. At December 31, 1994, the settlement rate and long-term rate of return on plan assets assumptions were 8.5% and 10%, respectively. The long-term rate of annual compensation increase assumption was 3.5% for 1995 and 1996 and 4% thereafter. At December 31, 1995 and 1994, the Company's net accrued pension liability included in Retirement Benefits in the Balance Sheet was $64 million and $66 million, respectively.

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

(b) Other Postretirement Benefits

Centerior Energy sponsors jointly with its subsidiaries 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. The Company 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. Prior to 1993, the costs of these benefits were expensed as paid, which was consistent with rate-making practices.

The components of the total postretirement benefit costs for 1993 through 1995 were as follows:

	1995	1994	1993
	(millions of dollars)		
Service cost for benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on accumulated postretirement benefit obligation	7	7	6
Amortization of transition obligation at January 1, 1993 of $63 million over 20 years	2	3	3
VTP curtailment cost (includes $6 million transition obligation adjustment)	—	—	32
Total costs	$10	$11	$42

These amounts included costs for the Company and its pro rata share of the Service Company's costs.

In 1995, 1994 and 1993, the Company deferred incremental SFAS 106 expenses (in excess of the amounts paid) of $1 million, $2 million and $37 million, respectively, pursuant to a provision of the Rate Stabilization Program. See Note 7(d).

The accumulated postretirement benefit obligation and accrued postretirement benefit cost for the Company and its share of the Service Company's obligation are as follows:

	December 31, 1995	1994
	(millions of dollars)	
Accumulated postretirement benefit obligation attributable to:		
Retired participants	$(76)	$(79)
Fully eligible active plan participants	(1)	—
Other active plan participants	(9)	(7)
Accumulated postretirement benefit obligation	(86)	(86)
Unrecognized net gain from variance between assumptions and experience	(9)	(7)
Unamortized transition obligation	49	51
Accrued postretirement benefit cost	$(46)	$(42)

The Balance Sheet classification of Retirement Benefits at December 31, 1995 and 1994 includes only the Company's accrued postretirement benefit cost of $39 million and $37 million, respectively, and excludes the Service Company's portion since the Service Company's total accrued cost is carried on its books.

A September 30 measurement date was used for 1995 and 1994 reporting. At December 31, 1995 and 1994, the settlement rate and the long-term rate of annual compensation increase assumptions were the same as those discussed for pension reporting in Note 9(a). At December 31, 1995, the assumed annual health care cost trend rates (applicable to gross eligible charges) were 8% for medical and 7.5% for dental in 1996. Both rates reduce gradually to a fixed rate of 4.75% by 2003. 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 one percentage point in each future year, the accumulated postretirement benefit obligation as of December 31, 1995 would increase by $3 million and the aggregate of the service and interest cost components of the annual postretirement benefit cost would increase by $0.3 million.

(10) Guarantees

The Company has guaranteed certain loan and lease obligations of a coal supplier under a long-term coal supply contract. At December 31, 1995, the principal amount of the loan and lease obligations guaranteed by the Company was $14 million. The prices under the contract which includes certain minimum payments are sufficient to satisfy the loan and lease obligations and mine closing costs over the life of the contract. If the contract is terminated early for any reason, the Company would attempt to reduce the termination charges and would ask the PUCO to allow recovery of such charges from customers through the fuel factor.

(11) Capitalization

(a) Capital Stock Transactions

Preferred stock shares retired during the three years ended December 31, 1995 are listed in the following table.

	1995	1994	1993
	(thousands of shares)		
Subject to Mandatory Redemption:			
$100 par $9.375	(17)	(17)	(17)
25 par 2.81	(400)	(800)	(800)
Total	(417)	(817)	(817)

(b) Equity Distribution Restrictions

Federal law prohibits the Company from paying dividends out of capital accounts. However, the Company may pay dividends out of appropriated retained earnings and current earnings. At December 31, 1995, the Company had $183 million of appropriated retained earnings for the payment of preferred stock dividends. The Company is prohibited from paying a common stock dividend by a provision in its mortgage that essentially requires such dividends to be paid out of the total balance of retained earnings, which currently is a deficit.

(c) Preferred and Preference Stock

Amounts to be paid for preferred stock which must be redeemed during the next five years are $1.665 million in each year 1996 through 1999 only.

The annual preferred stock mandatory redemption provisions are as follows:

	Shares To Be Redeemed	Beginning in	Price Per Share
$100 par $9.375	16,650	1985	$100

The annualized preferred dividend requirement at December 31, 1995 was $17 million.

The preferred dividend rates on the Company's Series A and B fluctuate based on prevailing interest rates and market conditions. The dividend rates for these issues averaged 7.75% and 8.58%, respectively, in 1995.

Preference stock authorized for the Company is 5,000,000 shares with a $25 par value. No preference shares are currently outstanding.

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

(d) Long-Term Debt and Other Borrowing Arrangements

Long-term debt, less current maturities, was as follows:

Year of Maturity	Actual or Average Interest Rate at December 31, 1995	December 31, 1995	December 31, 1994
		(millions of dollars)	
First mortgage bonds:			
1997	6.125%	$ 31	$ 31
1998	10.00	1	1
1999	7.25	100	100
2001-2005	7.85	207	207
2011-2015	3.85	31	31
2016-2020	7.82	166	67
2021-2023	7.74	148	148
		684	585
Secured medium-term notes due 1997-2021*	8.41	238	250
Term bank loans	—	—	62
Notes due 1997**	8.75	8	25
Debentures due 2002	8.70	135	135
Pollution control notes due 1997-2010	6.59	5	99
Other — net	—	(2)	(2)
Total Long-Term Debt		$1,068	$1,154

* Secured by first mortgage bonds.

** Secured by subordinated mortgage collateral.

Long-term debt matures during the next five years as follows: $56 million in 1996, $40 million in 1997, $39 million in 1998, $119 million in 1999 and $31 million in 2000.

The Company's mortgage constitutes a direct first lien on substantially all property owned and franchises held by the Company. Excluded from the lien, among other things, are cash, securities, accounts receivable, fuel, supplies and automotive equipment.

Certain credit agreements of the Company contain covenants relating to fixed charge coverage ratios and limitations on secured financing other than through first mortgage bonds or certain other transactions. In June 1995, the Company and Cleveland Electric replaced letters of credit in connection with the sale and leaseback of Beaver Valley Unit 2 that were due to expire with new letters of credit expiring in June 1999. The letters of credit are in an aggregate amount of approximately $225 million and are secured by first mortgage bonds of the Company and Cleveland Electric in the proportion of 60% and 40%, respectively. At December 31, 1995, the Company had outstanding $52 million of bank loans and notes secured by subordinated mortgage collateral.

(12) Short-Term Borrowing Arrangements

Centerior Energy has a $125 million revolving credit facility through May 1996. Centerior Energy and the Service Company may borrow under the facility, with all borrowings jointly and severally guaranteed by the Company and Cleveland Electric. Centerior Energy plans to transfer any of its borrowed funds to the Company and Cleveland Electric. The credit agreement is secured with first mortgage bonds of the Company and Cleveland Electric in the proportion of 60% and 40%, respectively. The banks' fee is 0.625% per annum payable quarterly in addition to interest on any borrowings. There were no borrowings under the facility at December 31, 1995. Also, the Company and Cleveland Electric may borrow from each other on a short-term basis. At December 31, 1995, the Company had total short-term borrowings of $21 million from its affiliates with a weighted average interest rate of 6.25%.

(13) Financial Instruments

The estimated fair values at December 31, 1995 and 1994 of financial instruments that do not approximate their carrying amounts in the Balance Sheet are as follows:

	December 31, 1995 Carrying Amount	1995 Fair Value	1994 Carrying Amount	1994 Fair Value
	(millions of dollars)			
Capitalization and Liabilities:				
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	$ 7	$ 6	$ 18	$ 19
Long-Term Debt (including current portion)	1,126	1,137	1,227	1,116

Noncash investments in the Nuclear Plant Decommissioning Trusts are summarized in the following table.

	December 31, 1995	December 31, 1994
	(millions of dollars)	
Type of Securities:		
Federal Government	$21	$21
Municipal	11	14
Total	$32	$35
Maturities:		
Due within one year	$ 1	$ 9
Due in one to five years	9	7
Due in six to 10 years	11	7
Due after 10 years	11	12
Total	$32	$35

The fair value of these trusts is estimated based on the quoted market prices for the investment securities. As a result of adopting the new accounting standard for certain investments in debt and equity securities, SFAS 115, in

1994, the carrying amount of these trusts approximates fair value. The fair value of the Company's 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, 1995 and 1994 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, 1995.

	Quarters Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
	(millions of dollars)			
1995				
Operating Revenues	$206	$215	$246	$206
Operating Income	43	45	59	41
Net Income	20	22	33	22
Earnings Available for Common Stock	15	17	29	18
1994				
Operating Revenues	$217	$216	$227	$204
Operating Income	43	43	53	40
Net Income	19	20	29	15
Earnings Available for Common Stock	13	14	24	11

(15) Pending Merger of the Company into Cleveland Electric

In March 1994, Centerior Energy announced a plan to merge the Company into Cleveland Electric. Since the Company and Cleveland Electric affiliated in 1986, efforts have been made to consolidate operations and administration as much as possible to achieve maximum cost savings.

Various aspects of the merger are subject to the approval of the FERC and other regulatory authorities. The FERC has deferred action on the merger application until the merits of the open access transmission tariffs proposed by the Company and Cleveland Electric are addressed in hearings. The PUCO and the Pennsylvania Public Utility Commission have approved the merger. NRC action on the request by the Company and Cleveland Electric for authorization to transfer certain NRC licenses to the merged entity is not expected until approval has been obtained from the FERC.

In June 1995, share owners of the Company's preferred stock approved the merger and share owners of Cleveland Electric's preferred stock approved the authorization of additional shares of preferred stock. When the merger becomes effective, share owners of the Company's preferred stock will exchange their shares for preferred stock shares of Cleveland Electric having substantially the same terms. Debt holders of the merging companies will become debt holders of Cleveland Electric.

For the merging companies, the combined pro forma operating revenues were $2.516 billion, $2.422 billion and $2.475 billion and the combined pro forma net income (loss) was $281 million, $268 million and $(876) million for the years 1995, 1994 and 1993, respectively. The pro forma data is based on accounting for the merger on a method similar to a pooling of interests. The pro forma data is not necessarily indicative of the results of operations which would have been reported had the merger been in effect during those years or which may be reported in the future. The pro forma data should be read in conjunction with the audited financial statements of both the Company and Cleveland Electric.

Report of Independent Public Accountants

To the Share Owners and
Board of Directors of
The Toledo Edison Company:

We have audited the accompanying balance sheet and statement of preferred stock of The Toledo Edison Company (a wholly owned subsidiary of Centerior Energy Corporation) as of December 31, 1995 and 1994, and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1995. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Toledo Edison Company as of December 31, 1995 and 1994, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1995, in conformity with generally accepted accounting principles.

As discussed further in Note 9, a change was made in the method of accounting for postretirement benefits other than pensions in 1993.

Arthur Andersen LLP

Cleveland, Ohio
February 21, 1996

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
1995	$238	184	254	65	741	133	874	—	$874
1994	227	181	251	64	723	142	865	—	865
1993	229	180	244	71	724	147	871	—	871
1992	215	175	236	61	687	158	845	—	845
1991	230	184	236	90	740	147	887	—	887
1985	185	129	214	26	554	22	576	6	582

Operating Expenses (millions of dollars)

Year	Fuel & Purchased Power	Other Operation & Maintenance	Generation Facilities Rental Expense, Net	Depreciation & Amortization	Taxes, Other Than FIT	Deferred Operating Expenses, Net	Federal Income Taxes (Credit)	Total Operating Expenses
1995	$157	225	104	84	91	(17)	42	$686
1994	167	229	104	83	90	(21)	33	685
1993	173	352 *(a)*	104	76	91	(4) *(b)*	(10)	782
1992	169	236	106	77	91	(17)	33	695
1991	178	243	113	72 *(c)*	89	1	32	728
1985	166	141	—	44	48	—	53	452

Income (Loss) (millions of dollars)

Year	Operating Income	AFUDC—Equity	Other Income & Deductions, Net	Deferred Carrying Charges, Net	Federal Income Taxes—Credit (Expense)	Income (Loss) Before Interest Charges
1995	$188	1	6	14	(2)	$ 207
1994	180	1	3	15	(2)	197
1993	89	1	(232) *(d)*	(161) *(b)*	129	(174)
1992	150	1	1	41	(1)	192
1991	159	1	5	22	(6)	181
1985	130	105	11	—	38	284

Income (Loss) (millions of dollars)

Year	Debt Interest	AFUDC—Debt	Net Income (Loss)	Preferred Stock Dividends	Earnings (Loss) Available for Common Stock
1995	$111	(1)	97	18	$ 79
1994	116	(1)	82	20	62
1993	116	(1)	(289)	23	(312)
1992	122	(1)	71	24	47
1991	132	(1)	50	25	25
1985	155	(45)	174	42	132

(a) Includes early retirement program expenses and other charges of $107 million.
(b) Includes write-off of phase-in deferrals of $241 million, consisting of $55 million of deferred operating expenses and $186 million of deferred carrying charges.

Year	Electric Sales (millions of KWH)						Electric Customers (thousands at year end)				Residential Usage		
	Residential	Commercial	Industrial	Wholesale	Other	Total	Residential	Commercial	Industrial & Other	Total	Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
1995	2 164	1 748	4 174	2 563	500	11 149	260	27	4	291	8 384	10.99¢	$921.23
1994	2 056	1 711	4 099	2 548	499	10 913	257	26	4	287	8 044	11.04	888.30
1993	2 039	1 672	3 776	2 146	490	10 123	255	26	4	285	7 997	11.23	897.65
1992	1 941	1 619	3 563	2 753	478	10 354	255	26	5	286	7 632	11.08	845.99
1991	2 041	1 683	3 543	2 587	482	10 336	255	26	4	285	7 990	11.26	897.41
1985	1 901	1 436	3 429	611	451	7 828	246	24	4	274	7 770	9.72	755.00

Year	Load (MW & %)				Energy (millions of KWH)					Fuel	
					Company Generated						
	Net Seasonal Capability	Peak Load	Capacity Margin	Load Factor	Fossil	Nuclear	Total	Purchased Power	Total	Fuel Cost Per KWH	Efficiency—BTU Per KWH
1995	1 651	1 738	(5.3)%	62.4%	4 576	6 761	11 337	299	11 636	1.32¢	10 341
1994	1 726	1 620	6.1	64.7	5 160	5 419	10 579	773	11 352	1.35	10 298
1993	1 726	1 568	9.2	64.3	5 548	4 791	10 339	196	10 535	1.42	10 146
1992	1 759	1 514	13.9	63.2	4 656	6 293	10 949	(82)	10 867	1.41	10 284
1991	1 757	1 510	14.1	64.5	4 848	6 003	10 851	95	10 946	1.44	10 327
1985	1 338	1 374	(2.7)	66.8	5 744	952	6 696	1 683	8 379	1.90	10 124

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
1995	$2 896	942	1 954	28	98	$2 080	$ 56	$3 474
1994	2 899	892	2 007	30	125	2 162	41	3 502
1993	2 837	788	2 049	40	142	2 231	43	3 510
1992	2 847	760	2 087	280	164	2 531	44	3 939
1991	2 692	709	1 983	308	198	2 489	54	3 926
1985	1 392	390	1 002	1 755	228	2 985	389	3 373

Capitalization (millions of dollars & %)

Year	Common Stock Equity		Preferred Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
1995	$763	38%	5	—%	210	10%	1 068	52%	$2 046
1994	685	34	7	—	210	10	1 154	56	2 056
1993	623	30	28	1	210	10	1 225	59	2 086
1992	935	39	50	2	210	9	1 178	50	2 373
1991	888	38	64	3	210	9	1 158	50	2 320
1985	950	36	154	6	230	8	1 339	50	2 673

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

(d) Includes write-off of Perry Unit 2 of $232 million.

INVESTOR INFORMATION

Share Owner Information

Share Owner Services

Communications regarding stock transfer requirements, lost certificates, dividends and changes of address should be directed to Share Owner Services at Centerior Energy Corporation. Correspondence should be sent to the address indicated below for the Stock Transfer Agent. To reach Share Owner Services by phone, call:

In Cleveland area 447-2400

Outside Cleveland area (800) 433-7794

Please have your account number ready when calling.

Stock 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

Stock Registrar

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

Investor Relations

Inquiries from security analysts and institutional investors should be directed to Ronald E. Seeholzer, Manager-Investor Relations, at Centerior Energy Corporation, P.O. Box 94661, Cleveland, OH 44101-4661 or by telephone at (216) 447-3339.

Exchange Listings

Preferred Stock ($25 par value): 8.84% series, $2.365 series, Adjustable Series A and Adjustable Series B are listed on the New York Stock Exchange.

Preferred Stock ($100 par value): 4¼%, 8.32%, 7.76% and 10% series are listed on the American Stock Exchange.

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

Centerior Energy Corporation has a Dividend Reinvestment and Stock Purchase Plan which provides Toledo Edison share owners of record and other investors a convenient means of purchasing shares of Centerior 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 Centerior common stock through the Plan. Information relating to the Plan and the CX•IRA may be obtained from Share Owner Services.

Independent Public Accountants

Arthur Andersen LLP
1717 East Ninth Street
Cleveland, OH 44114

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.

Bond and Debenture Information

First Mortgage Bond Trustee and Paying Agent

The Chase Manhattan Bank, N.A.
Corporate Trust Customer Service Dept.
Box 3015
4 Chase Metrotech Center, 3rd Floor
Brooklyn, NY 11245
(800) 355-2663

Debenture Trustee and Paying Agent

Fifth Third Bank
Corporate Trust Administration
38 Fountain Square Plaza
Cincinnati, OH 45263
(513) 579-5132

The Toledo Edison Company
300 Madison Avenue
Toledo, OH 43652-0001

BULK RATE
U.S. POSTAGE
P A I D
CLEVELAND, OHIO
PERMIT NO. 409