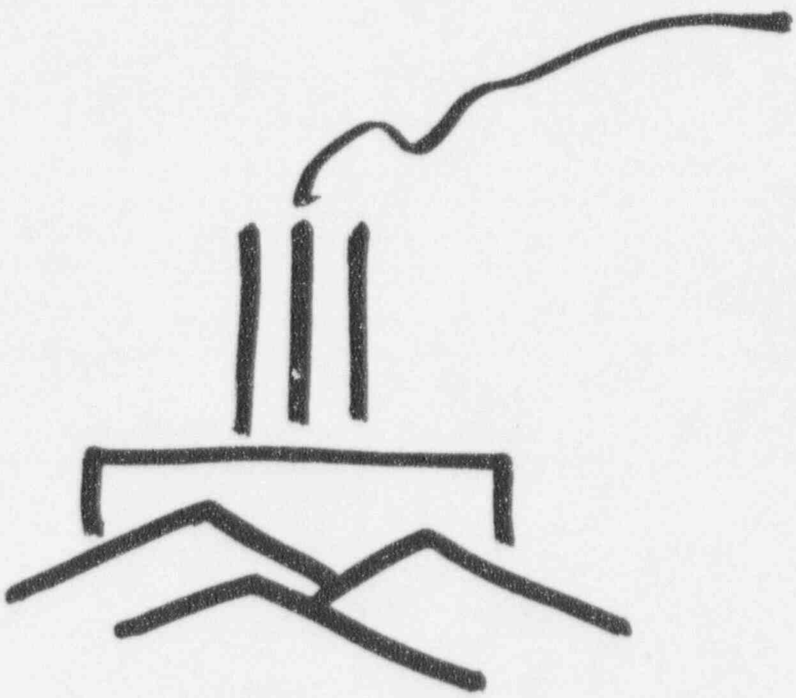
The Toledo Edison Company

A subsidiary of Centerior Energy Corporation



Annual Report 1994

Contents

About Toledo Edison

The Company, a wholly owned subsidiary of Centerior Energy Corporation, provides electric service to about 620,000 people in a 2,500-square mile area of northwestern Ohio, including the City of Toledo. 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. The Company's 1,887 employees serve about 287,000 customers.

Executive Offices

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

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 .... *Gary R. Leidich*
Vice President .... *Terrence G. Linnert*
Treasurer .... *David M. Blank*
Controller .... *E. Lyle Pepin*
Secretary .... *Janis T. Percio*

Printed on recycled paper

Management's Financial Analysis

Outlook

Strategic Plan

We made significant strides in achieving the objectives of the comprehensive strategic action plan announced in January 1994. Centerior Energy Corporation (Centerior Energy), along with The Toledo Edison Company (Company) and The Cleveland Electric Illuminating Company (Cleveland Electric), created the strategic plan to strengthen their financial and competitive position through the year 2001. 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 an industry 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. To achieve these objectives, we will continue to control expenditures and reduce our outstanding debt and preferred stock. In addition, we will increase revenues by finding new uses for existing assets and resources, implementing new marketing programs and restructuring rates when appropriate. We will also improve the operating performance of our generating plants and take other appropriate actions.

During 1994, we made progress toward most of our long-term objectives. The Company and Cleveland Electric initiated a marketing plan designed to increase total retail revenues (exclusive of fuel cost recovery revenues and weather influences) by 2-3% annually through 2001. Our new customer service activities are intended to raise our customer satisfaction rating. Our employees achieved enough of their established objectives for the year to receive a $500 per eligible employee incentive compensation award. The work undertaken during refueling outages at the Davis-Besse Nuclear Power Station (Davis-Besse) and Perry Nuclear Power Plant Unit 1 (Perry Unit 1) as well as the outage work at our fossil-fueled plants should help us achieve our long-term objective of reducing variable power costs to a more competitive level. Strong cash flow continued in 1994 and the Company's fixed-income obligations were reduced by $66 million. Also, the Company's total operation and maintenance expenses declined $22 million, exclusive of one-time charges in 1993.

We are taking aggressive steps to increase revenues through our enhanced marketing plan and to control costs. The full impact of these efforts will take time. In the meantime, the Company and Cleveland Electric must raise revenues by restructuring rates. Accordingly, the Company and Cleveland Electric are preparing to file a request with The Public Utilities Commission of Ohio (PUCO) to be effective in 1996. Meaningful cost control and marketing strategies will mitigate the need for additional rate increases and help us meet competition.

Competition

We are implementing strategies designed to create and enhance our competitive advantages and to overcome the competitive disadvantages that we face due to regulatory and tax constraints and our high retail cost structure.

Currently our most pressing competition comes from municipal electric systems in our service area. Our rates are generally higher than those of municipal systems due largely to their exemption from taxation, the lower cost financing available to them, the continued availability to them of lower cost power through short-term power purchases and their access to cheaper governmental power. We are seeking to address the tax disparity through the legislative process. In 1994, the Ohio Governor's Tax Commission recommended the replacement of the gross receipts and personal property taxes currently levied only on investor-owned utilities and collected through rates with a different tax collected from customers of all electric utilities, including municipal systems. Investor-owned utilities would reduce rates upon repeal of the existing taxes. We are now working to submit this proposal to the Ohio legislature.

We face the threat that municipalities in our service area could establish new systems and continue expanding existing systems. We are responding with aggressive marketing programs and by emphasizing the value of our service and the risks of a municipal system: substantial, long-term debt; no guarantee of low-cost wholesale electricity; the difficulty of forecasting costs; and the uncertainty of market share as a result of our aggressive competition. Generally, these municipalities have determined that developing a system is not feasible or have agreed with us not to pursue development of a system at this time. Although some communities continue to be interested in municipalization, we believe that we offer the best value and most reliable source of electric service in our territory.

The Energy Policy Act of 1992 will increase competition in the electric utility industry by allowing broader access to a utility's transmission system. It should not significantly increase the competitive threat to us since we have been required to wheel electricity to municipal systems in our service area since 1977 under operating licenses for our nuclear generating units. Further, the government could eventually require utilities to deliver power from other utilities or generation sources to their retail customers. To combat this threat, we are offering incentives such as energy-efficiency improvements and reductions in demand charges for increased electricity usage to our industrial and commercial customers in return for long-term commitments. Most of our large industrial and

commercial customers have entered into sole-supplier contracts with us. More than 80% of our industrial revenues under contract will not be up for renewal until 1997 or later. As these contracts expire, we expect to renegotiate them and retain the customers.

Rate Matters

Under the Rate Stabilization Program discussed in Note 7, we agreed to freeze base rates until 1996 and limit rate increases through 1998. In exchange, we are permitted to defer through 1995 and subsequently recover certain costs not currently recovered in rates and to accelerate the amortization of certain benefits. Amortization and recovery of the deferrals are expected to begin in 1996 with future rate recognition and will continue over the average life of the related assets, or between 17 and 30 years. The continued use of these regulatory accounting measures in 1995 will be dependent upon our continuing assessment and conclusion that there will be probable recovery of such deferrals in future rates. Our analysis leading to certain year-end 1993 financial actions and the strategic plan also included an evaluation of our regulatory accounting measures. See Regulatory Accounting below and Note 7. We decided that, once the deferral of expenses and acceleration of benefits under the Rate Stabilization Program are completed in 1995, we should no longer plan to use these measures to the extent we have in the past.

Regulatory Accounting

As described in Notes 1(a) and 7, the Company complies with the provisions of Statement of Financial Accounting Standards (SFAS) 71. We continually 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 establish rates to recover operating costs, return requirements and the amortization of regulatory assets and (2) a significant change in the manner in which rates are set by the PUCO from cost-based regulations to some other form of regulations. In the event we determine that the Company no longer meets the criteria for following SFAS 71, the Company would be required to record a before-tax charge to write off the regulatory assets shown in Note 7. 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 would also result in an impairment of the net book value of the Company's property, plant and equipment.

The Company's write-off in 1993 of the phase-in deferred operating expenses and carrying charges (phase-in deferrals) discussed in Note 7 resulted from our conclusion that projected revenues for the 1994-1998 period would not provide for recovery of such deferrals as scheduled by the PUCO order. This short time frame for recovery of the phase-in deferrals is a requirement under the accounting standard for phase-in plans of regulated enterprises, SFAS 92. The remaining recovery periods for all remaining regulatory assets are between 17 and 34 years. We believe the Company's rates will provide for recovery of these assets over the relevant periods and SFAS 71 continues to apply.

Nuclear Operations

The Company has interests in three nuclear generating units — Davis-Besse, 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 have been operating extremely well, with each unit having a three-year availability average at year-end 1994 that exceeded the three-year industry average of 80% for similar reactors. However, the three-year availability average of Perry Unit 1 was below the three-year industry availability average for that reactor type.

In 1994, Davis-Besse had an availability factor of 88%. Further, Davis-Besse completed the shortest refueling and maintenance outage in its history in 1994, returning to service just 46 days after shutting down. Cleveland Electric is in the process of upgrading Perry Unit 1 to the same level. For seven months in 1994, Perry Unit 1 was out of service for its fourth refueling and maintenance outage. Work was also performed in connection with the comprehensive course of action developed in 1993 to improve the operating performance of Perry Unit 1. Work in connection with that course of action is ongoing.

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 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.

Hazardous Waste Disposal Sites

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended (Superfund) established programs addressing the cleanup of hazardous waste disposal sites, emergency preparedness and other issues. The 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 amounts involved, are often unsubstantiated and subject to dispute. Superfund provides that all "potentially responsible parties" (PRPs) for a particular site can 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, 1994 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 Company and Cleveland Electric plan to seek preferred stock share owner approval in mid-1995. The merger is expected to be effective in 1995. See Note 15.

Inflation

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

Capital Resources and Liquidity

1992-1994 Cash Requirements

We need cash for normal corporate operations, the mandatory retirement of securities and constructing and modifying facilities. Construction is needed to meet anticipated demand for electric service, comply with government regulations and protect the environment. Over the three-year period 1992-1994, construction and mandatory retirement needs totaled approximately \$370 million. In addition, we exercised options to redeem approximately \$460 million of our securities.

We raised \$603 million through security issues and term bank loans during the 1992-1994 period. The Company also utilized short-term borrowings to help meet its cash needs. Although write-offs of the Company's Perry Nuclear Power Plant Unit 2 (Perry Unit 2) investment and phase-in deferrals in 1993 negatively affected earnings, they did not adversely affect cash flow. See Notes 4(b) and 7.

1995 and Beyond Cash Requirements

Estimated cash requirements for 1995-1999 for the Company are \$288 million for construction and \$378 million for the mandatory redemption of debt and preferred stock. The Company expects to meet nearly all of its 1995 and 1996 cash requirements of approximately \$145 million and \$154 million, respectively, through internal cash generation and current cash resources. The Company expects to meet nearly all of its 1997-1999 requirements through internal cash generation and current cash resources. If economical, additional securities may be redeemed under optional redemption provisions. We expect that the Company's continued strong cash flow will reduce borrowing requirements and outstanding debt and preferred stock during this period.

Cash expenditures to comply with the Clean Air Act Amendments of 1990 (Clean Air Act) are estimated to be approximately \$22 million over the 1995-1999 period. See Note 4(a).

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, 1994, the Company would have been permitted to issue approximately $525 million of additional first mortgage bonds.

The Company also is able to raise funds through the sale of subordinated 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, 1994, the Company would have been permitted to issue approximately $28 million of additional preferred stock at an assumed dividend rate of 12%. There are no restrictions on the Company's ability to issue preference stock.

In 1995, the Company plans to raise funds through the collateralization of accounts receivable. In addition, the Company expects to issue first mortgage bonds as collateral security for the sale by a public authority of tax-exempt bonds.

The Company is a party to a $205 million revolving credit facility which runs through mid-1996. See Note 12. The Company had $88 million of cash and temporary cash investments at the end of 1994. The Company is unable to issue commercial paper because of its below investment grade commercial paper ratings.

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
Unsecured notes	B+	B1
Preferred stock	B	b2

Results of Operations

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 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.

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). Two other significant reasons for lower operation and maintenance expenses in 1994 were a smaller work force and ongoing cost reduction measures. 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. 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, 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.

1993 vs. 1992

Factors contributing to the 3.1% increase in 1993 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$ 38
Wholesale Sales	(11)
Base Rates and Miscellaneous	(3)
Fuel Cost Recovery Revenues	2
Total	$ 26

The revenue increase resulted primarily from the different weather conditions and the changes in the composition of the sales mix among customer categories. Weather accounted for approximately $15 million of higher 1993 base rate revenues. Hot summer weather in 1993 boosted residential and commercial kilowatt-hour sales. In contrast, the 1992 summer was the coolest in 56 years for Northwestern Ohio. Residential and commercial sales also increased as a result of colder late-winter temperatures in 1993 which increased electric heating-related demand. Residential and commercial sales increased 5.1% and 3.2%, respectively, in 1993. Industrial sales increased 6% as a result of increased sales to large automotive manufacturers, petroleum refiners and the broad-based, smaller industrial customer group. Other sales decreased 18% because of fewer sales to wholesale customers. Generating plant outages and retail customer demand limited power availability for bulk power transactions. As a result, total sales decreased 2.2% in 1993. Base rates and miscellaneous revenues decreased in 1993 primarily from lower revenues under contracts having reduced rates with certain large customers and a declining rate structure tied to usage. The contracts have been negotiated to meet competition and encourage economic growth. The increase in 1993 fuel cost recovery revenues resulted from changes in the fuel cost factors. The weighted average of these factors increased about 2%.

For 1993, operating revenues were 26% residential, 21% commercial, 28% industrial and 25% other and kilowatt-hour sales were 20% residential, 17% commercial, 37% industrial and 26% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.11 and $.06, respectively. The changes from 1992 were not significant.

Operating expenses increased 13% in 1993. The increase in total operation and maintenance expenses resulted from the $88 million of net benefit expenses related to the VTP, other charges totaling $19 million and a slight increase in other operation and maintenance expenses. Deferred operating expenses decreased because of the write-off of the phase-in deferred operating expenses in 1993. Federal income taxes decreased as a result of lower pretax operating income.

As mentioned above, $232 million of our Perry Unit 2 investment was written off in 1993. Credits for carrying charges recorded in nonoperating income decreased because of the write-off of the phase-in deferred carrying charges in 1993. The federal income tax credit for nonoperating income in 1993 resulted from the write-offs.

Income Statement

The Toledo Edison Company

	For the years ended December 31,		
	1994	1993	1992
		(millions of dollars)	
Operating Revenues (1)	$865	$ 871	$845
Operating Expenses			
Fuel and purchased power	167	173	169
Other operation and maintenance	229	245	236
Generation facilities rental expense, net	104	104	106
Early retirement program expenses and other	—	107	—
Total operation and maintenance	500	629	511
Depreciation and amortization	83	76	77
Taxes, other than federal income taxes	90	91	91
Deferred operating expenses, net	(21)	(4)	(17)
Federal income taxes (credit)	33	(10)	33
	685	782	695
Operating Income	180	89	150
Nonoperating Income (Loss)			
Allowance for equity funds used during construction	1	1	1
Other income and deductions, net	3	—	1
Write-off of Perry Unit 2	—	(232)	—
Deferred carrying charges, net	15	(161)	41
Federal income taxes — credit (expense)	(2)	129	(1)
	17	(263)	42
Income (Loss) Before Interest Charges	197	(174)	192
Interest Charges			
Debt interest	116	116	122
Allowance for borrowed funds used during construction	(1)	(1)	(1)
	115	115	121
Net Income (Loss)	82	(289)	71
Preferred Dividend Requirements	20	23	24
Earnings (Loss) Available for Common Stock	$ 62	$(312)	$ 47

(1) Includes revenues from all bulk power sales to Cleveland Electric of $111 million, $120 million and $130 million in 1994, 1993 and 1992, respectively.

Retained Earnings

	For the years ended December 31,		
	1994	1993	1992
		(millions of dollars)	
Retained Earnings (Deficit) at Beginning of Year	$(175)	$ 137	$ 90
Additions			
Net income (loss)	82	(289)	71
Deductions			
Preferred stock dividends declared	(20)	(23)	(24)
Net Increase (Decrease)	62	(312)	47
Retained Earnings (Deficit) at End of Year	$(113)	$(175)	$137

The accompanying notes are an integral part of these statements.

Cash Flows

	For the years ended December 31,		
	1994	1993	1992
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income (Loss)	$ 82	$(289)	$ 71
Adjustments to Reconcile Net Income (Loss) to Cash from Operating Activities:			
Depreciation and amortization	83	76	77
Deferred federal income taxes	46	(160)	28
Investment tax credits, net	—	—	(5)
Unbilled revenues	3	(4)	1
Deferred fuel	3	—	(4)
Deferred carrying charges, net	(15)	161	(41)
Leased nuclear fuel amortization	44	38	56
Deferred operating expenses, net	(21)	(4)	(17)
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	1	(3)	—
Changes in inventories	(2)	10	(9)
Changes in accounts payable	(15)	16	(8)
Changes in working capital affecting operations	(16)	21	7
Other noncash items	10	14	13
Total Adjustments	120	479	97
Net Cash from Operating Activities	202	190	168
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	—	(40)	40
Notes payable to affiliates	—	—	(30)
First mortgage bond issues	31	20	276
Secured medium-term note issues	—	93	48
Debenture issue	—	—	135
Maturities, redemptions and sinking funds	(98)	(89)	(531)
Nuclear fuel lease obligations	(49)	(47)	(52)
Dividends paid	(20)	(23)	(24)
Premiums, discounts and expenses	—	(1)	(8)
Net Cash from Financing Activities	(136)	(87)	(146)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(41)	(42)	(48)
Interest capitalized as allowance for borrowed funds used during construction	(1)	(1)	(1)
Loans to affiliates	—	—	12
Sale and leaseback restructuring fees	—	—	(43)
Contributions to nuclear plant decommissioning trusts	(12)	(4)	(4)
Other cash received (applied)	(6)	10	(1)
Net Cash from Investing Activities	(60)	(37)	(85)
Net Change in Cash and Temporary Cash Investments	6	66	(63)
Cash and Temporary Cash Investments at Beginning of Year	82	16	79
Cash and Temporary Cash Investments at End of Year	$ 88	$ 82	$ 16

(1) Interest paid (net of amounts capitalized) was $94 million, $92 million and $95 million in 1994, 1993 and 1992, respectively. Income taxes paid were $5 million, $7 million and $3 million in 1994, 1993 and 1992, respectively.

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

The accompanying notes are an integral part of this statement.

Balance Sheet

	December 31, 1994	December 31, 1993
	(millions of dollars)	
ASSETS		
Property, Plant and Equipment		
Utility plant in service	$2,899	$2,837
Less: accumulated depreciation and amortization	892	788
	2,007	2,049
Construction work in progress	30	40
	2,037	2,089
Nuclear fuel, net of amortization	119	142
Other property, less accumulated depreciation	6	—
	2,162	2,231
Current Assets		
Cash and temporary cash investments	88	82
Amounts due from customers and others, net	62	63
Amounts due from affiliates	19	16
Unbilled revenues	22	25
Materials and supplies, at average cost	45	43
Fossil fuel inventory, at average cost	12	12
Taxes applicable to succeeding years	72	71
Other	2	2
	322	314
Deferred Charges and Other Assets		
Amounts due from customers for future federal income taxes	405	382
Unamortized loss from Beaver Valley Unit 2 sale	101	105
Unamortized loss on reacquired debt	28	32
Carrying charges and operating expenses	379	343
Nuclear plant decommissioning trusts	38	26
Other	67	77
	1,018	965
Total Assets	$3,502	$3,510

The accompanying notes are an integral part of this statement.

	December 31, 1994	December 31, 1993
	(millions of dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shares, $5 par value: 60 million authorized; 39.1 million outstanding in 1994 and 1993	$ 196	$ 196
Premium on capital stock	481	481
Other paid-in capital	121	121
Retained earnings (deficit)	(113)	(175)
Common stock equity	685	623
Preferred stock		
With mandatory redemption provisions	7	28
Without mandatory redemption provisions	210	210
Long-term debt	1,154	1,225
	2,056	2,086
Current Liabilities		
Current portion of long-term debt and preferred stock	83	57
Current portion of nuclear fuel lease obligations	36	49
Accounts payable	48	63
Accounts payable to affiliates	31	27
Accrued taxes	75	90
Accrued interest	27	27
Other	16	16
	316	329
Deferred Credits and Other Liabilities		
Unamortized investment tax credits	87	94
Accumulated deferred federal income taxes	541	471
Unamortized gain from Bruce Mansfield Plant sale	198	208
Accumulated deferred rents for Bruce Mansfield Plant and Beaver Valley Unit 2	54	50
Nuclear fuel lease obligations	87	103
Retirement benefits	103	98
Other	60	71
	1,130	1,095
Total Capitalization and Liabilities	$3,502	$3,510

Statement of Preferred Stock

	1994 Shares Outstanding	Current Call Price Per Share	December 31, 1994	December 31, 1993
			(millions of dollars)	
$100 par value, 3,000,000 preferred shares authorized and				
$25 par value, 12,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$100 par $9.375	83,500	$101.98	$ 8	$ 10
25 par 2.81	400,000	25.62	10	30
			18	40
Less: Current maturities			11	12
Total Preferred Stock, with Mandatory Redemption Provisions			$ 7	$ 28
Not subject to mandatory redemption:				
$100 par $ 4.25	160,000	104.625	$ 16	$ 16
4.56	50,000	101.00	5	5
4.25	100,000	102.00	10	10
8.32	100,000	102.46	10	10
7.76	150,000	102.437	15	15
7.80	150,000	101.65	15	15
10.00	190,000	101.00	19	19
25 par 2.21	1,000,000	25.25	25	25
2.365	1,400,000	27.75	35	35
Series A Adjustable	1,200,000	25.75	30	30
Series B Adjustable	1,200,000	25.75	30	30
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 Federal Energy Regulatory Commission (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 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 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 \$59 million, \$71 million and \$60 million in 1994, 1993 and 1992, 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 Amortization

The cost of property, plant and equipment is depreciated over their estimated useful lives on a straight-line basis. The annual straight-line depreciation provision for nonnuclear property expressed as a percent of average depreciable utility plant in service was 3.5% in 1994 and 3.6% in both 1993 and 1992. The annual straight-line depreciation rate for nuclear property is 2.5%.

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 allowing net earnings to 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 \$4 million level in 1992. The accruals are reflected in current rates. The increased accruals were derived from recently 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 amounts 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, 1994 includes $44 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 is reviewing the accounting for removal costs, including decommissioning. If such 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.

(f) Property, Plant and Equipment

Property, plant and equipment are stated at original cost less amounts ordered by the PUCO to be written off. Construction costs include related payroll taxes, 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 9.87% in 1994, 10.22% in 1993 and 10.96% in 1992.

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 leases. See Note 7. 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. Such losses and gains are either amortized over the remainder of the original life of the debt issue retired or amortized over the life of the new debt issue when the proceeds of a new issue are used for the debt redemption. The amortizations are included in debt interest expense.

(i) Federal Income Taxes

The 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.

Investment tax credits are deferred and amortized over the lives of the applicable property as a reduction of

depreciation expense. See Note 7 for a discussion of the amortization of certain unrestricted excess deferred taxes and unrestricted investment tax credits under the Rate Stabilization Program.

(2) Utility Plant Sale and Leaseback Transactions

The 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, all for terms of about 29½ years. These leases 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. Additional lease provisions provide other purchase options along with conditions for mandatory termination of the leases (and possible repurchase of the leasehold interests) for events of default. These events include noncompliance with any of several financial covenants discussed in Note 11(d).

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.

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

Future minimum lease payments under the operating leases at December 31, 1994 are summarized as follows:

Year	For the Company	For Cleveland Electric
	(millions of dollars)	
1995	$ 103	$ 63
1996	125	63
1997	102	63
1998	102	63
1999	108	70
Later Years	1,918	1,321
Total Future Minimum Lease Payments	$2,458	$1,643

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1994, 1993 and 1992 as annual rental expense for the Mansfield Plant leases was $45 million. The amounts recorded in 1994, 1993 and 1992 as annual rental expense for the Beaver Valley Unit 2 lease were $64 million, $63 million and $66 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 $108 million, $103 million and $108 million in 1994, 1993 and 1992, respectively. We anticipate that this sale will continue indefinitely. The future minimum lease payments through the year 2017 associated with Beaver Valley Unit 2 aggregate $1.413 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, 1994 includes the following facilities owned by the Company as a tenant in common with other utilities and Lessors:

Generating Unit	In-Service Date	Ownership Share	Ownership Megawatts	Power Source	Plant in Service	Construction Work in Progress	Accumulated Depreciation
					(millions of dollars)		
Davis-Besse	1977	48.62%	429	Nuclear	$ 642	$ 4	$179
Perry Unit 1	1987	19.91	238	Nuclear	1,043	4	197
Beaver Valley Unit 2 and Common Facilities (Note 2)	1987	1.65	13	Nuclear	204	3	42
Total					$1,889	$11	$418

(4) Construction and Contingencies

(a) Construction Program

The estimated cost of the Company's construction program for the 1995-1999 period is $303 million, including AFUDC of $15 million and excluding nuclear fuel.

The 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 1994 in connection with Clean Air Act compliance amounted to $1 million. The plan will require additional capital expenditures over the 1995-2004 period of approximately $32 million for nitrogen oxide control equipment and plant modifications. In addition, higher fuel and other operation and maintenance expenses may be incurred. The anticipated rate increase associated with the capital expenditures and higher expenses would be less than 2% over the ten-year period.

(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. See Note 14.

(c) Hazardous Waste Disposal Sites

The Company is aware of its potential involvement in the cleanup of several hazardous waste disposal sites. The Company has accrued a liability totaling $5 million at December 31, 1994 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 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 (plus any inflation adjustment) 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, 1995. 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. Under these policies, the Company can be assessed a maximum of $10 million during a policy year if the reserves available to the insurer are inadequate to pay claims arising out of an accident at any nuclear facility covered by the insurer.

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. At December 31, 1994, $307 million ($125 million for the Company and $182 million for Cleveland Electric) of nuclear fuel was financed ($157 million from intermediate-term notes and $150 million from bank credit arrangements). The intermediate-term notes mature in 1996 and 1997. 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 $61 million, $34 million and $10 million, respectively, at December 31, 1994. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $4 million in 1994 and $6 million in both 1993 and 1992. The estimated future lease amortization payments based on projected consumption are $43 million in 1995, $38 million in 1996, $34 million in 1997, $31 million in 1998 and $27 million in 1999.

(7) Regulatory Matters

The Company is subject to the provisions of SFAS 71. Regulatory assets represent probable future revenues to the Company associated with certain incurred costs, which it will recover from customers through the ratemaking process. Regulatory assets in the Balance Sheet are as follows:

	December 31, 1994	1993
	(millions of dollars)	
Amounts due from customers for future federal income taxes	$405	$382
Unamortized loss from Beaver Valley Unit 2 sale	101	105
Unamortized loss on reacquired debt	28	32
Pre-phase-in deferrals*	229	236
Rate Stabilization Program deferrals	150	107
Total	$913	$862

* 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, 1994, 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 17 to 34 years. We continually assess the effects of competition and the changing industry and regulatory environment on operations and the Company's ability to recover the regulatory assets. In the event that we determine that future revenues would not be provided for recovery of any regulatory asset, such asset would be required to be written off. See Management's Financial Analysis — Outlook-Regulatory Accounting.

The Company will file a request with the PUCO to restructure rates to increase revenues to be effective in 1996 which will include provision for recovery of the Rate Stabilization Program deferrals. We believe that rates will be set at a level consistent with cost-based regulations and will provide revenues to recover the then-current operating costs, return requirements and amortization of all regulatory assets listed above.

The Rate Stabilization Program that the PUCO approved in October 1992 was designed to encourage economic growth in the Company's service area by freezing the Company's base rates until 1996 and limiting subsequent rate increases to specified annual amounts not to exceed $89 million over the 1996-1998 period.

As part of the Rate Stabilization Program, during the 1992-1995 period the Company is allowed to defer and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. The continued use of these regulatory accounting measures will be dependent upon our continuing assess-

ment and conclusion that there will be probable recovery of such deferrals in future rates.

The regulatory accounting measures we are eligible to record through December 31, 1995 include the deferral of post-in-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988 and the deferral of operating expenses equivalent to an accumulated excess rent reserve for Beaver Valley Unit 2 (which resulted from the April 1992 refinancing of SLOBs as discussed in Note 2). The cost deferrals recorded in 1994, 1993 and 1992 pursuant to these provisions were $40 million, $39 million and $32 million, respectively. The regulatory accounting measures also provide for the accelerated amortization of certain unrestricted excess deferred tax and unrestricted investment tax credit balances and interim spent fuel storage accrual balances for Davis-Besse. The total amount of such regulatory benefits recognized pursuant to these provisions was $18 million in both 1994 and 1993 and $5 million in 1992.

The Rate Stabilization Program also authorized the Company to defer and subsequently recover the incremental expenses associated with the adoption of the accounting standard for postretirement benefits other than pensions (SFAS 106). In 1994 and 1993, we deferred $2 million and $37 million, respectively, pursuant to this provision. Amortization and recovery of these deferrals are expected to commence in 1996 and to be completed by no later than 2012. See Note 9(b).

In 1993, upon completing a comprehensive study which led to our current 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. Such deferrals were scheduled to be recovered over the 1994 through 1998 period. 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). See Note 14. Additionally, based on our assessment of business conditions, we concluded that, once the deferral of expenses and acceleration of benefits under our Rate Stabilization Program are completed in 1995, we should no longer plan to use regulatory accounting measures to the extent we have in the past.

(8) Federal Income Tax

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

	1994	1993	1992
	(millions of dollars)		
Operating Expenses:			
Current	$18	$ 36	$26
Deferred	15	(46)	7
Total Expense (Credit) to Operating Expenses	33	(10)	33
Nonoperating Income:			
Current	(29)	(15)	(20)
Deferred	31	(114)	21
Total Expense (Credit) to Nonoperating Income	2	(129)	1
Total Federal Income Tax Expense (Credit)	$35	$(139)	$34

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 statutory rate (35% in 1994 and 1993 and 34% in 1992), is reconciled to the amount of federal income tax recorded on the books as follows:

	1994	1993	1992
	(millions of dollars)		
Book Income (Loss) Before Federal Income Tax	$117	$(428)	$105
Tax (Credit) on Book Income (Loss) at Statutory Rate	$ 41	$(150)	$ 36
Increase (Decrease) in Tax:			
Write-off of Perry Unit 2	—	16	—
Write-off of phase-in deferrals	—	8	—
Depreciation	(3)	(12)	(6)
Rate Stabilization Program	(9)	(10)	(2)
Sale and leaseback transactions and amortization	5	5	5
Other items	1	4	1
Total Federal Income Tax Expense (Credit)	$ 35	$(139)	$ 34

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 $120 million loss with a corresponding $42 million reduction in federal income tax liability. Because of the alternative minimum tax (AMT), $24 million of the $42 million was realized in 1994. The remaining $18 million will not be realized until 1999.

In August 1993, the Revenue Reconciliation Act of 1993 was enacted. Retroactive to January 1, 1993, the top marginal corporate income tax rate increased to 35%. The change in tax rate did not materially impact the results of operations for 1993, but increased Accumulated Deferred Federal Income Taxes for the future tax obligation by approximately $29 million. Since the PUCO has historically permitted recovery of such taxes from customers when they become payable, the deferred charge, Amounts Due from Customers for Future Federal Income Taxes, also was increased by $29 million.

Under SFAS 109, temporary differences and carryforwards resulted in deferred tax assets of $178 million and deferred tax liabilities of $719 million at December 31, 1994 and deferred tax assets of $178 million and deferred tax liabilities of $649 million at December 31, 1993. These are summarized as follows:

	December 31, 1994	1993
	(millions of dollars)	
Property, plant and equipment	$606	$534
Deferred carrying charges and operating expenses	83	79
Net operating loss carryforwards	(54)	(39)
Investment tax credits	(51)	(55)
Sale and leaseback transactions	(3)	—
Other	(40)	(48)
Net deferred tax liability	$541	$471

For tax purposes, net operating loss (NOL) carryforwards of approximately $154 million are available to reduce future taxable income and will expire in 2003 through 2009. The 35% tax effect of the NOLs is $54 million. Additionally, AMT credits of $69 million that may be carried forward indefinitely are available to reduce future regular 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 and an additional $10 million of pension costs for VTP benefits paid to retirees from corporate funds. The $10 million is not included in the pension data reported in the following table. A credit of $81 million resulting from a settlement of pension obligations through lump sum payments to almost all the VTP retirees partially offset the VTP expenses.

Pension and VTP costs (credits) for Centerior Energy and its subsidiaries for 1992 through 1994 were comprised of the following components:

	1994	1993	1992
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 13	$ 15	$ 15
Interest cost on projected benefit obligation	26	37	38
Actual return on plan assets	(2)	(65)	(24)
Net amortization and deferral	(34)	4	(45)
Net pension costs (credits)	3	(9)	(16)
VTP cost	—	205	—
Settlement gain	—	(81)	—
Net costs (credits)	$ 3	$115	$(16)

Pension and VTP costs (credits) for the Company and its pro rata share of the Service Company's costs were $1 million and $53 million for 1994 and 1993, respectively. The costs for 1992 were negligible.

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, 1994	1993
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$278	$333
Nonvested benefits	2	37
Accumulated benefit obligation	280	370
Effect of future compensation levels	37	53
Total projected benefit obligation	317	423
Plan assets at fair market value	362	386
Funded status	45	(37)
Unrecognized net loss (gain) from variance between assumptions and experience	(79)	11
Unrecognized prior service cost	10	10
Transition asset at January 1, 1987 being amortized over 19 years	(39)	(43)
Net accrued pension liability	$(63)	$(59)

A September 30, 1994 measurement date was used for 1994 reporting. At December 31, 1994, the settlement (discount) 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, 1993, the settlement rate and long-term rate of return on plan assets assumptions were 7.25% and 8.75%, respectively. The long-term rate of annual compensation increase assumption was 4.25%. At December 31, 1994 and 1993, the Company's net accrued pension liability included in Retirement Benefits in the

Balance Sheet was $66 million and $65 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 ratemaking practices.

The components of the total postretirement benefit costs for 1994 and 1993 were as follows:

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

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

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

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, 1994	1993
	(millions of dollars)	
Accumulated postretirement benefit obligation attributable to:		
Retired participants	$(79)	$(88)
Other active plan participants	(7)	(9)
Accumulated postretirement benefit obligation	(86)	(97)
Unrecognized net loss (gain) from variance between assumptions and experience	(7)	5
Unamortized transition obligation	51	54
Accrued postretirement benefit cost	$(42)	$(38)

The Balance Sheet classification of Retirement Benefits at December 31, 1994 and 1993 includes only the Company's accrued postretirement benefit cost of $37 million and $33 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, 1994 measurement date was used for 1994 reporting. At December 31, 1994 and 1993, 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, 1994, the assumed annual health care cost trend rates (applicable to gross eligible charges) are 8.5% for medical and 8% for dental in 1995. 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, 1994 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, 1994, the principal amount of the loan and lease obligations guaranteed by the Company was $17 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, 1994 are listed in the following table.

	1994	1993	1992
	(thousands of shares)		
Subject to Mandatory Redemption:			
$100 par $11.00	—	—	(25)
9.375	(17)	(17)	(17)
25 par 2.81	(800)	(800)	—
Total	(817)	(817)	(42)

(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, 1994, the Company had $104 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 $11 million in 1995 and $2 million in each year 1996 through 1999.

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
25 par 2.81	400,000	1993	25

The annualized preferred dividend requirement at December 31, 1994 was $19 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 7.66% and 8.44%, respectively, in 1994.

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, 1994	December 31, 1994	December 31, 1993
		(millions of dollars)	
First mortgage bonds:			
1997	6.125%	$ 31	$ 31
1998	10.00	1	1
1999	7.25	100	100
2000-2004	7.85	207	207
2010-2014	3.85	31	31
2015-2019	8.00	67	67
2020-2023	7.74	148	148
		585	585
Secured medium term notes due 1996-2021	8.44	250	250
Term bank loans due 1996	9.08	62	109
Notes due 1996-1997	9.49	25	43
Debentures due 2002	8.70	135	135
Pollution control notes due 1996-2015	12.11	99	105
Other — net	—	(2)	(2)
Total Long-Term Debt		$1,154	$1,225

Long-term debt matures during the next five years as follows: $71 million in 1995, $91 million in 1996, $40 million in 1997, $39 million in 1998 and $119 million in 1999.

The Company issued $141 million aggregate principal amount of secured medium-term notes in 1992 and 1993. The notes are secured by first mortgage bonds.

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 unsecured loan agreements of the Company contain covenants relating to capitalization ratios, fixed charge coverage ratios and limitations on secured financing other than through first mortgage bonds or certain other transactions. Two reimbursement agreements relating to separate letters of credit issued in connection with the sale and leaseback of Beaver Valley Unit 2 contain several financial covenants affecting the Company, Cleveland Electric and Centerior Energy. Among these are covenants relating to fixed charge coverage ratios and capitalization ratios. The write-offs recorded at December 31, 1993 caused the Company, Cleveland Electric and Centerior Energy to violate certain covenants contained in the two reimbursement agreements. The affected creditors waived those violations in exchange for a subordinate mortgage security interest on the properties of the Company and Cleveland Electric. The Company provided the same security interest to certain other creditors because their agreements require equal treatment. At December 31, 1994, the Company provided subordinate mortgage collateral for $152 million of unsecured debt, $228 million of bank letters of credit and a $205 million revolving credit facility. The bank letters of credit are joint and several obligations of the Company and Cleveland Electric and the revolving credit facility is an obligation of Centerior Energy that is jointly and severally guaranteed by the Company and Cleveland Electric.

(12) Short-Term Borrowing Arrangements

Centerior Energy has a $205 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 facility agreement as amended provides the participating banks with a subordinate mortgage security interest on the properties of the Company

and Cleveland Electric. 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, 1994. The facility agreement contains covenants relating to capitalization and fixed charge coverage ratios for the Company, Cleveland Electric and Centerior Energy.

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

(13) Financial Instruments

Except for the Nuclear Plant Decommissioning Trusts at December 31 1994, as discussed below, the estimated fair values at December 31, 1994 and 1993 of financial instruments that do not approximate their carrying amounts in the Balance Sheet are as follows:

	December 31,			
	1994		1993	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(millions of dollars)			
Assets:				
Nuclear Plant Decommissioning Trusts	$ 38	$ 38	$ 26	$ 27
Capitalization and Liabilities:				
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	18	19	40	42
Long-Term Debt (including current portion)	1,227	1,116	1,271	1,314

The Nuclear Plant Decommissioning Trusts at December 31, 1994 included $21 million of federal governmental securities and $14 million of municipal securities. The securities had the following maturities: $9 million due within one year; $7 million due in one to five years; $7 million due in six to 10 years, and $12 million due after 10 years. 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 is equal to the 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, 1994 and 1993 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, 1994.

	Quarters Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
	(millions of dollars)			
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
1993				
Operating Revenues	$215	$210	$239	$207
Operating Income (Loss)	39	42	17	(10)
Net Income (Loss)	18	20	(5)	(323)
Earnings (Loss) Available for Common Stock	12	14	(10)	(328)

Earnings for the quarter ended September 30, 1993 were decreased by $35 million as a result of the recording of $54 million of VTP pension-related benefits.

Earnings for the quarter ended December 31, 1993 were decreased as a result of year-end adjustments for the $232 million write-off of Perry Unit 2 (see Note 4(b)), the $241 million write-off of the phase-in deferrals (see Note 7) and $19 million of other charges. These adjustments decreased quarterly earnings by $345 million.

(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 PUCO and the Pennsylvania Public Utility Commission have approved the merger. In addition, the merger must be approved by share owners of the Company's preferred stock. Share owners of Cleveland Electric's preferred stock must approve 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. The merging companies plan to seek preferred stock share owner approval in mid-1995. The merger is expected to be effective in 1995.

For the merging companies, the combined pro forma operating revenues were $2.422 billion, $2.475 billion and $2.439 billion and the combined pro forma net income (loss) was $268 million, $(876) million and $276 million for the years 1994, 1993 and 1992, 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, 1994 and 1993, and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1994. 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, 1994 and 1993, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1994, 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 17, 1995

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
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
1990	224	175	236	78	713	150	863	—	863
1984	173	115	195	45	528	20	548	9	557

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
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
1990	174	262	111	73	79	(10)	21	710
1984	145	125	—	50	47	—	66	433

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
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
1990	153	3	5	43	9	213
1984	124	83	7	—	34	248

Income (Loss) (millions of dollars)

Year	Debt Interest	AFUDC—Debt	Net Income (Loss)	Preferred Stock Dividends	Earnings (Loss) Available for Common Stock
1994	$116	(1)	82	20	$ 62
1993	116	(1)	(289)	23	(312)
1992	122	(1)	71	24	47
1991	132	(1)	50	25	25
1990	135	(3)	81	25	56
1984	129	(35)	154	35	119

(a) Includes early retirement program expenses and other charges of $107 million in 1993.

(b) Includes write-off of phase-in deferrals of $241 million in 1993, consisting of $55 million of deferred operating expenses and $186 million of deferred carrying charges.

(c) In 1991, 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.

Year	Electric Sales (millions of KWH): Residential	Commercial	Industrial	Wholesale	Other	Total	Electric Customers (year end): Residential	Commercial	Industrial & Other	Total	Residential Usage: Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
1994	2 056	1 711	4 099	2 548	499	10 913	256 998	25 921	3 965	286 884	8 044	11.04¢	$888.30
1993	2 039	1 672	3 776	2 146	490	10 123	255 109	26 049	4 076	285 234	7 997	11.23	897.65
1992	1 941	1 619	3 563	2 753	478	10 354	255 299	25 870	4 372	285 541	7 632	11.08	845.99
1991	2 041	1 683	3 543	2 587	482	10 336	254 500	26 044	4 444	284 988	7 990	11.26	897.41
1990	1 950	1 614	3 617	2 333	496	10 010	253 965	25 822	4 555	284 342	7 692	11.48	882.99
1984	1 958	1 398	3 444	473	440	7 713	243 912	23 891	3 920	271 723	8 045	8.81	709.09

Year	Load (MW & %): Net Seasonal Capability	Peak Load	Capacity Margin	Load Factor	Energy (millions of KWH): Company Generated: Fossil	Nuclear	Total	Purchased Power	Total	Fuel: Fuel Cost Per KWH	Efficiency—BTU Per KWH
1994	1 729	1 620	6.3%	64.7%	5 160	5 419	10 579	773	11 352	1.35¢	10 298
1993	1 729	1 568	9.3	64.3	5 548	4 791	10 339	196	10 535	1.42	10 146
1992	1 762	1 514	14.1	63.2	4 656	6 293	10 949	(82)	10 867	1.41	10 284
1991	1 759	1 510	14.2	64.5	4 848	6 003	10 851	95	10 946	1.44	10 327
1990	1 751	1 516	13.4	63.0	5 535	4 219	9 754	902	10 656	1.50	10 220
1984	1 688	1 327	21.4	68.2	5 181	2 091	7 272	888	8 160	1.73	10 193

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
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
1990	2 604	640	1 964	349	224	2 537	87	3 913
1984	1 373	365	1 008	1 413	197*(e)*	2 618	356	2 936

Capitalization (millions of dollars & %)

Year	Common Stock Equity		Preferred Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
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
1990	881	39	66	3	210	9	1 097	49	2 254
1984	814	36	158	7	200	9	1 110	48	2 282

(d) Includes write-off of Perry Unit 2 of $232 million in 1993.

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

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 642-6900 or 447-2400

Outside Cleveland area 1-800-433-7794

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 Terrence R. Moran, Manager-Investor Relations, at the address of the Stock Transfer Agent or by telephone at (216) 447-2882.

Exchange Listings

Preferred—$25 par value—8.84%, $2.365 and $2.81 series, Adjustable Series A and Adjustable Series B—New York Stock Exchange.

Preferred—$100 par value—4¼%, 8.32%, 7.76% and 10% series—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 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

Bond Trustee and Paying Agent

The Chase Manhattan Bank, N.A.
Institutional Trust Group
4 Chase Metrotech Center, 3rd Floor
Brooklyn, NY 11245
(718) 242-7287

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
PAID
CLEVELAND, OHIO
PERMIT NO. 409

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K

(Mark One)
[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (FEE REQUIRED)**

For the fiscal year ended December 31, 1994

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)**

For the transition period from to

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-9130	CENTERIOR ENERGY CORPORATION (An Ohio Corporation) 6200 Oak Tree Boulevard Independence, Ohio 44131 Telephone (216) 447-3100	34-1479083
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (An Ohio Corporation) 55 Public Square Cleveland, Ohio 44113 Telephone (216) 622-9800	34-0150020
1-3583	THE TOLEDO EDISON COMPANY (An Ohio Corporation) 300 Madison Avenue Toledo, Ohio 43652 Telephone (419) 249-5000	34-4375005

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X . No ___.

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

The aggregate market value of Centerior Energy Corporation Common Stock, without par value, held by non-affiliates was $1,443,307,154 on February 28, 1995 based on the closing sale price of $9.75 as quoted for that date on a composite transactions basis in *The Wall Street Journal* and on the 148,031,503 shares of Common Stock outstanding on that date. Centerior Energy Corporation is the sole holder of the 79,590,689 shares and 39,133,887 shares of the outstanding common stock of The Cleveland Electric Illuminating Company and The Toledo Edison Company, respectively.

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

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Centerior Energy Corporation	Common Stock, without par value	New York Stock Exchange
		Chicago Stock Exchange
		Pacific Stock Exchange
The Cleveland Electric Illuminating Company	Cumulative Serial Preferred Stock, without par value:	
	$7.40 Series A	New York Stock Exchange
	$7.56 Series B	New York Stock Exchange
	Adjustable Rate, Series L	New York Stock Exchange
	Depository Shares: 1993 Series A, each share representing 1/20 of a share of Serial Preferred Stock, $42.40 Series T (without par value)	New York Stock Exchange
	First Mortgage Bonds:	
	8-3/4% Series due 2005	New York Stock Exchange
	9-1/4% Series due 2009	New York Stock Exchange
	8-3/8% Series due 2011	New York Stock Exchange
	8-3/8% Series due 2012	New York Stock Exchange
The Toledo Edison Company	Cumulative Preferred Stock, par value $100 per share:	
	4-1/4% Series	American Stock Exchange
	8.32% Series	American Stock Exchange
	7.76% Series	American Stock Exchange
	10% Series	American Stock Exchange
	Cumulative Preferred Stock, par value $25 per share:	
	8.84% Series	New York Stock Exchange
	$2.365 Series	New York Stock Exchange
	Adjustable Rate, Series A	New York Stock Exchange
	Adjustable Rate, Series B	New York Stock Exchange
	$2.81 Series	New York Stock Exchange
	First Mortgage Bonds:	
	7-1/2% Series due 2002	New York Stock Exchange
	8% Series due 2003	New York Stock Exchange

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

Registrant	Title of Each Class
Centerior Energy Corporation	None
The Cleveland Electric Illuminating Company	None
The Toledo Edison Company	Cumulative Preferred Stock, par value $100 per share: 4.56% Series and 4.25% Series

DOCUMENTS INCORPORATED BY REFERENCE

Description	Part of Form 10-K Into Which Document Is Incorporated
Portions of Proxy Statement of Centerior Energy Corporation, dated March 14, 1995	Part III

TABLE OF CONTENTS

	Page Number

This combined Form 10-K is separately filed by Centerior Energy Corporation, The Cleveland Electric Illuminating Company and The Toledo Edison Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant, except that information relating to either or both of the Operating Companies is also attributed to Centerior Energy.

GLOSSARY OF TERMS

The following terms and abbreviations used in the text of this report are defined as indicated:

Term	Definition
AFUDC	Allowance for Funds Used During Construction.
AMP-Ohio	American Municipal Power-Ohio, Inc., an Ohio not-for-profit corporation, the members of which are certain Ohio municipal electric systems.
Beaver Valley Unit 2	Unit 2 of the Beaver Valley Power Station, in which the Operating Companies have ownership and leasehold interests.
CAPCO Group	Central Area Power Coordination Group.
Centerior Energy or Centerior	Centerior Energy Corporation.
Centerior System	Centerior Energy, the Operating Companies and the Service Company.
Clean Air Act	Federal Clean Air Act of 1970 as amended.
Clean Air Act Amendments	November 1990 Amendments to the Clean Air Act.
Clean Water Act	Federal Water Pollution Control Act as amended.
Cleveland Electric	The Cleveland Electric Illuminating Company, an electric utility subsidiary of Centerior Energy and a member of the CAPCO Group.
Consol	Consolidation Coal Company.
CPP	Cleveland Public Power, a municipal electric system operated by the City of Cleveland.
Davis-Besse	Davis-Besse Nuclear Power Station.

Term	Definition
Detroit Edison	Detroit Edison Company, an electric utility.
District of Columbia Circuit Appeals Court	United States Court of Appeals for the District of Columbia Circuit.
DOE	United States Department of Energy.
Duquesne	Duquesne Light Company, an electric utility subsidiary of DQE, Inc. and a member of the CAPCO Group.
ECAR	East Central Area Reliability Coordination Group.
Energy Act	Energy Policy Act of 1992.
Federal Power Act	Federal Power Act, as amended, codified in Chapter 12 of Title 16 of the United States Code.
FERC	Federal Energy Regulatory Commission.
Holding Company Act	Public Utility Holding Company Act of 1935.
Mansfield Plant	Bruce Mansfield Generating Plant, a coal-fired power plant, in which the Operating Companies have leasehold interests as joint and several lessees.
Note or Notes	Note or Notes to the Financial Statements in the Centerior Energy, Cleveland Electric and Toledo Edison Annual Reports for 1994 (Note or Notes, where used, refers to all three companies unless otherwise specified).
NPDES	National Pollutant Discharge Elimination System.
NRC	United States Nuclear Regulatory Commission.
Ohio Edison	Ohio Edison Company, an electric utility and a member of the CAPCO Group.
Ohio EPA	Ohio Environmental Protection Agency.
Ohio Power	Ohio Power Company, an electric utility subsidiary of American Electric Power Company, Inc.

Term	Definition
Ohio Valley	The Ohio Valley Coal Company, the successor corporation to The Nacco Mining Company and a subsidiary of Ohio Valley Resources, Inc.
Operating Companies (individually, Operating Company)	Cleveland Electric and Toledo Edison.
OPSB	Ohio Power Siting Board.
PaPUC	Pennsylvania Public Utility Commission.
Penelec	Pennsylvania Electric Company, an electric utility subsidiary of General Public Utilities Corporation.
Pennsylvania Power	Pennsylvania Power Company, an electric utility subsidiary of Ohio Edison and a member of the CAPCO Group.
Perry Plant	Perry Nuclear Power Plant.
Perry Unit 1	Unit 1 of the Perry Plant, in which the Operating Companies have ownership interests.
Perry Unit 2	Unit 2 of the Perry Plant, in which the Operating Companies had ownership interests which were written off at December 31, 1993.
PUCO	The Public Utilities Commission of Ohio.
Quarto	Quarto Mining Company, a subsidiary of Consol.
SALP	Systematic Assessment of Licensee Performance - the NRC's performance evaluation of a nuclear unit.
SEC	United States Securities and Exchange Commission.
Seneca Plant	Seneca Power Plant, a pumped-storage, hydro-electric generating station jointly owned by Cleveland Electric and Penelec.
Service Company	Centerior Service Company, a service subsidiary of Centerior Energy.

Term	Definition
Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980 and the Superfund Amendments and Reauthorization Act of 1986.
Toledo Edison	The Toledo Edison Company, an electric utility subsidiary of Centerior Energy and a member of the CAPCO Group.
USEC	United States Enrichment Corporation, formerly a part of the DOE.
U.S. EPA	United States Environmental Protection Agency.
Westinghouse	Westinghouse Electric Corporation.

PART I

Item 1. Business

THE CENTERIOR SYSTEM

Centerior Energy is a public utility holding company and the parent company of the Operating Companies and the Service Company. Centerior was incorporated under the laws of the State of Ohio in 1985 for the purpose of enabling Cleveland Electric and Toledo Edison to affiliate by becoming wholly owned subsidiaries of Centerior. The affiliation of the Operating Companies became effective in April 1986. Nearly all of the consolidated operating revenues of the Centerior System are derived from the sale of electric energy by Cleveland Electric and Toledo Edison.

The Operating Companies' combined service areas encompass approximately 4,200 square miles in northeastern and northwestern Ohio with an estimated population of about 2,450,000. At December 31, 1994, the Centerior System had 6,767 employees. Centerior Energy has no employees.

Cleveland Electric, which was incorporated under the laws of the State of Ohio in 1892, is a public utility engaged in the generation, purchase, transmission, distribution and sale of electric energy in an area of approximately 1,700 square miles in northeastern Ohio, including the City of Cleveland. Cleveland Electric also provides electric energy at wholesale to other electric utility companies and to two municipal electric systems (directly and through AMP-Ohio) in its service area. Cleveland Electric serves approximately 747,000 customers and derives approximately 77% of its total electric retail revenue from customers outside the City of Cleveland. Principal industries served by Cleveland Electric include those producing steel and other primary metals; automotive and other transportation equipment; chemicals; electrical and nonelectrical machinery; fabricated metal products; and rubber and plastic products. Nearly all of Cleveland Electric's operating revenues are derived from the sale of electric energy. At December 31, 1994, Cleveland Electric had 3,547 employees of which about 54% were represented by one union having a collective bargaining agreement with Cleveland Electric.

Toledo Edison, which was incorporated under the laws of the State of Ohio in 1901, is a public utility engaged in the generation, purchase, transmission, distribution and sale of electric energy in an area of approximately 2,500 square miles in northwestern Ohio, including the City of Toledo. Toledo Edison also provides electric energy at wholesale to other electric utility companies and to 13 municipally owned distribution systems (through AMP-Ohio) and one rural electric cooperative distribution system in its service area. Toledo Edison serves approximately 287,000 customers and derives approximately 57% of its total electric retail revenue from customers outside the City of Toledo. Principal industries served by Toledo Edison include metal casting, forming and fabricating; petroleum refining; automotive equipment and assembly; food processing; and glass. Nearly all of Toledo Edison's operating revenues are derived from the sale of electric energy. At December 31, 1994, Toledo Edison had 1,887 employees of which about 56% were represented by three unions having collective bargaining agreements with Toledo Edison.

The Service Company, which was incorporated in 1986 under the laws of the State of Ohio, is also a wholly owned subsidiary of Centerior Energy. It provides management, financial, administrative, engineering, legal, governmental and public relations and other services to Centerior Energy and the Operating Companies. At December 31, 1994, the Service Company had 1,333 employees.

MERGER OF THE OPERATING COMPANIES

In March 1994, Centerior Energy announced a plan to merge Toledo Edison into Cleveland Electric. Since Cleveland Electric and Toledo Edison affiliated in 1986, efforts have been made to consolidate operations and administration as much as possible to achieve maximum cost savings. On May 2, 1994, the Operating Companies filed a joint application for authorization and approval of the merger with the FERC. The PUCO, AMP-Ohio and the cities of Cleveland, Clyde and Bryan, Ohio have intervened in the FERC proceedings. The PUCO intervened as the state commission having jurisdiction, but has not opposed the Cleveland Electric and Toledo Edison application. On December 1, 1994, the PUCO approved the merger. (Approval of the merger was previously obtained from the PaPUC on July 7, 1994.) The other intervenors have opposed the merger citing concerns primarily relating to the merger's impact on competition. On December 8, 1994, the FERC advised Cleveland Electric and Toledo Edison by letter that the application to merge would be rejected unless the companies provide additional information and file a single system open-access transmission tariff offering comparable service. Cleveland Electric and Toledo Edison have advised the FERC that they intend to provide the additional information required in the December 8, 1994 letter, and that they intend to file an open-access transmission tariff offering comparable service.

The merger also must be approved by Toledo Edison preferred stock share owners. Preferred stock share owners of Cleveland Electric must approve the authorization of additional shares of preferred stock. When the merger becomes effective, the outstanding shares of Toledo Edison preferred stock will be exchanged for shares of Cleveland Electric preferred stock having substantially the same terms. Cleveland Electric and Toledo Edison plan to seek preferred share owner approval in mid-1995. The merger is expected to be effective in late 1995.

See Note 15 to the Operating Companies' Financial Statements for further discussion of this matter and "3. Combined Pro Forma Condensed Financial Statements (Unaudited)" contained under Item 14. of this Report for selected historical and combined pro forma financial information of Cleveland Electric and Toledo Edison.

CAPCO GROUP

Cleveland Electric and Toledo Edison are members of the CAPCO Group, a power pool created in 1967 with Duquesne, Ohio Edison and Pennsylvania Power. This pool affords greater reliability and lower cost of providing electric service through coordinated generating unit operations and maintenance and generating reserve back-up among the five companies. In addition, the CAPCO Group has completed programs to construct larger, more efficient electric generating units and to strengthen interconnections within the pool.

The CAPCO Group companies have placed in service nine major generating units, of which the Operating Companies have ownership or leasehold interests in seven (three nuclear and four coal-fired). Each CAPCO Group company owns, as a tenant-in-common, or leases a portion of certain of these generating units. Each company has the right to the net capability and associated energy of its respective ownership and leasehold portions of the units and is, severally and not jointly, obligated for the capital and operating costs equivalent to its respective ownership and leasehold portions of the units and the required fuel, except that the obligations of Pennsylvania Power are the joint and several obligations of that company and Ohio Edison and the leasehold obligations of Cleveland Electric and Toledo Edison are joint and several. (See "Operations--Fuel Supply".) For all plants but one, the company in whose service area a generating unit is located is responsible for the operation of that unit for all the owners, except for the procurement of nuclear fuel for a nuclear generating unit. The Mansfield Plant, which is located in Duquesne's service area, is operated by Pennsylvania Power. Each company owns the necessary interconnecting transmission facilities within its service area, and the other CAPCO Group companies contribute toward fixed charges and operating costs of those transmission facilities.

All of the CAPCO Group companies are members of ECAR, which is comprised of 32 electric companies located in nine contiguous states. ECAR's purpose is to improve reliability of bulk power supply through coordination of planning and operation of member companies' generation and transmission facilities.

CONSTRUCTION AND FINANCING PROGRAMS

Construction Program

The Centerior System carries on a continuous program of constructing transmission, distribution and general facilities and modifying existing generating facilities to meet anticipated demand for electric service, to comply with governmental regulations and to protect the environment. The Operating Companies' 1994 long-term (20-year) forecast, as filed with the PUCO (see "General Regulation--State Utility Commissions"), projects long-term annual growth rates in peak demand and kilowatt-hour sales for the Operating Companies of 0.5% and 1.0%, respectively, after demand-side management considerations. The Centerior System's integrated resource plan for the 1990s (which is included in the long-term forecast) combines peak clipping demand-side management programs with maximum utilization of existing generating capacity to postpone the need for new generating units until the next decade. Lake Shore Unit 18, a 245,000-kilowatt unit which was placed on cold standby status in October 1993, is scheduled to resume active status in 1998. According to the current long-term integrated resource plan, the next increment of new generating capacity that the Centerior System plans to put into service will be two 150,000-kilowatt units and one 80,000-kilowatt unit in 2008.

The following tables show, categorized by major components, the construction expenditures by Cleveland Electric and Toledo Edison and, by aggregating them, for the Centerior System during 1992, 1993 and 1994 and the estimated cost of their construction programs for 1995 through 1999, in each case including AFUDC and excluding nuclear fuel:

Cleveland Electric	Actual 1992	1993	1994	Estimated 1995	1996	1997	1998	1999
	(Millions of Dollars)							
Transmission, Distribution and General Facilities	$ 73	$ 85	$ 53	$ 86	$ 94	$ 97	$ 79	$ 88
Renovation and Modification of Generating Units								
Nuclear	26	16	18	17	18	16	13	14
Nonnuclear	56	65	61	53	35	53	54	60
Clean Air Act Amendments Compliance	1	9	24	20	2	11	23	17
Total	$156	$175	$156	$176	$149	$177	$169	$179

Toledo Edison	Actual 1992	1993	1994	Estimated 1995	1996	1997	1998	1999
	(Millions of Dollars)							
Transmission, Distribution and General Facilities	$ 25	$ 22	$ 18	$ 32	$ 33	$ 29	$ 26	$ 24
Renovation and Modification of Generating Units								
Nuclear	12	15	10	13	14	12	10	11
Nonnuclear	7	6	12	13	15	5	17	26
Clean Air Act Amendments Compliance	0	0	1	6	3	7	2	7
Total	$ 44	$ 43	$ 41	$ 64	$ 65	$ 53	$ 55	$ 68

Centerior System	Actual 1992	1993	1994	Estimated 1995	1996	1997	1998	1999
	(Millions of Dollars)							
Transmission, Distribution and General Facilities	$ 98	$107	$ 71	$118	$127	$126	$105	$112
Renovation and Modification of Generating Units								
Nuclear	38	31	28	30	32	28	23	25
Nonnuclear	63	71	73	66	50	58	71	86
Clean Air Act Amendments Compliance	1	9	25	26	5	18	25	24
Total	$200	$218	$197	$240	$214	$230	$224	$247

Each company in the CAPCO Group is responsible for financing the portion of the capital costs of nuclear fuel equivalent to its ownership and leased interest in the unit in which the fuel will be utilized. See "Operations--Fuel Supply--Nuclear" for information regarding nuclear fuel supplies and Note 6 regarding leasing arrangements to finance nuclear fuel capital costs. Nuclear fuel capital costs incurred by Cleveland Electric, Toledo Edison and the Centerior System during 1992, 1993 and 1994 and their estimated nuclear fuel capital costs for 1995 through 1999 are as follows:

	Actual			Estimated				
	1992	1993	1994	1995	1996	1997	1998	1999
	(Millions of Dollars)							
Cleveland Electric	$ 30	$ 26	$ 26	$ 18	$ 27	$ 33	$ 28	$ 29
Toledo Edison	$ 22	$ 20	$ 21	$ 12	$ 27	$ 27	$ 21	$ 26
Centerior System	$ 52	$ 46	$ 47	$ 30	$ 54	$ 60	$ 49	$ 55

Financing Program

Reference is made to Centerior Energy's, Cleveland Electric's and Toledo Edison's Management's Financial Analysis contained under Item 7 of this Report and to Notes 11 and 12 for discussions of the Centerior System's financing activity in 1994; debt and preferred stock redemption requirements during the 1995-1999 period; expected external financing needs during such period; restrictions on the issuance of additional debt securities and preferred stock; short-term and long-term financing capability; and securities ratings for the Operating Companies.

In the second quarter of 1995, Cleveland Electric and Toledo Edison expect to issue $53,900,000 and $45,000,000, respectively, of first mortgage bonds as collateral security for the sale by a public authority of corresponding principal amounts of tax-exempt bonds. The proceeds from the sales of the public authority's bonds will be used to refund like amounts of tax-exempt bonds that were issued in 1984. In addition, Cleveland Electric expects to issue $150,000,000 of first mortgage bonds in the second quarter of 1995. The proceeds of this issue will be used to reimburse Cleveland Electric for cash expended in the optional redemption of $26,000,000 principal amount of First Mortgage Bonds, 13-3/4% Series due 2005-A and to help fund the payment of required sinking fund obligations and maturing securities in 1995 and for general corporate purposes. Cleveland Electric and Toledo Edison also plan to raise funds through the collateralization of their accounts receivable in 1995. If cost effective, the Operating Companies may redeem additional securities under optional redemption provisions.

GENERAL REGULATION

Holding Company Regulation

Centerior Energy is currently exempt from regulation under the Holding Company Act.

The Energy Act contains, among other provisions, amendments to the Holding Company Act and the Federal Power Act. The Energy Act also adopted nuclear power licensing and related regulations, energy efficiency standards and incentives for the use of alternative transportation fuels. Amendments to the Holding Company Act create a new class of independent power producers known as "Exempt Wholesale Generators", which are exempt from the Holding Company Act corporate structure regulations and operate without SEC approval or regulation. Exempt Wholesale Generators may be owned by holding companies, electric utility companies or any other person.

State Utility Commissions

The Operating Companies are subject to the jurisdiction of the PUCO with respect to rates, service, accounting, issuance of securities and other matters. Under Ohio law, municipalities may regulate rates, subject to appeal to the PUCO if not acceptable to the utility. See "Electric Rates" for a description of certain aspects of Ohio rate-making law. The Operating Companies are also subject to the jurisdiction of the PaPUC in certain respects relating to their ownership interests in generating facilities located in Pennsylvania.

The PUCO is composed of five commissioners appointed by the Governor of Ohio from nominees recommended by a Public Utility Commission Nominating Council. Nominees must have at least three years' experience in one of several disciplines. Not more than three commissioners may belong to the same political party.

Under Ohio law, a public utility must file annually with the PUCO a long-term forecast of customer loads, facilities needed to serve those loads and prospective sites for those facilities. This forecast must include the following:

(1) Demand Forecast--the utility's 20-year forecast of sales and peak demand, before and after the effects of demand-side management programs.

(2) Integrated Resource Plan (required biennially)--the utility's projected mix of resource options to meet the projected demand.

(3) Short-Term Implementation Plan and Status Report (required biennially)--the utility's discussion of how it plans to implement its integrated resource plan over the next four years. Estimates of annual expenditures and security issuances associated with the integrated resource plan over the four-year period must also be provided.

The PUCO must hold a public hearing on the long-term forecast at least once every five years to determine the reasonableness of the forecast. The PUCO and the OPSB are required to consider the record of such hearings in proceedings for approving facility sites, changing rates, approving security issues and initiating energy conservation programs. Ohio law also permits electric utilities under PUCO jurisdiction to submit environmental compliance plans for PUCO review and approval. Ohio law requires that the PUCO make certain statutory findings prior to approving the environmental compliance plan, which includes that the plan is a reasonable least cost strategy for compliance with air quality requirements. In February 1993, the PUCO approved the Operating Companies' 1992 long-term forecast and environmental compliance plan. The PUCO held hearings in January 1995 on the Operating Companies' 1994 long-term forecast and has scheduled hearings in April 1995 on the Operating Companies' updated environmental compliance plan which was filed in January 1995.

The PUCO has jurisdiction over certain transactions by companies in an electric utility holding company system if it includes at least one Ohio electric utility and is exempt from regulation under Section 3(a)(1) or (2) of the Holding Company Act. Consequently, the Operating Companies must obtain PUCO

approval to invest in, lend funds to, guarantee the obligations of or otherwise finance or transfer assets to any nonutility company in the Centerior System, unless the transaction is in the ordinary course of business operations in which one company acts for or with respect to another company. Also, Centerior must obtain PUCO approval to make any investment in any nonutility subsidiaries, affiliates or associates if such investment would cause all such capital investments to exceed 15% of Centerior's consolidated capitalization unless such funds were provided by nonutility subsidiaries, affiliates or associates.

The PUCO has a reserve capacity policy for electric utilities in Ohio stating that (i) 20% of service area peak load excluding interruptible load is an appropriate generic benchmark for an electric utility's reserve margin; (ii) a reserve margin exceeding 20% gives rise to a presumption of excess capacity, but may be appropriate if it confers a positive net present benefit to customers or is justified by unique system characteristics; and (iii) appropriate remedies for excess capacity (possibly including disallowance of costs in rates) will be determined by the PUCO on a case-by-case basis.

Ohio Power Siting Board

The OPSB has state-wide jurisdiction, except to the extent pre-empted by Federal law, over the location, need for and certain environmental aspects of electric generating units with a capacity of 50,000 kilowatts or more and transmission lines with a rating of at least 125 kV.

Federal Energy Regulatory Commission

The Operating Companies are each subject to the jurisdiction of the FERC with respect to the transmission and sale of power at wholesale in interstate commerce, interconnections with other utilities, accounting and certain other matters. Cleveland Electric is also subject to FERC jurisdiction with respect to its ownership and operation of the Seneca Plant.

Nuclear Regulatory Commission

The nuclear generating units in which the Operating Companies have an interest are subject to regulation by the NRC. The NRC's jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety, antitrust considerations and environmental impacts.

Owners of nuclear units are required to purchase the full amount of nuclear liability insurance available. See Note 5(b) for a description of nuclear insurance coverages.

Other Regulation

The Operating Companies are subject to regulation by Federal, state and local authorities with regard to the location, construction and operation of certain facilities. The Operating Companies are also subject to regulation by local authorities with respect to certain zoning and planning matters.

ENVIRONMENTAL REGULATION

General

The Operating Companies are subject to regulation with respect to air quality, water quality and waste disposal matters. Federal environmental legislation affecting the operations and properties of the Operating Companies includes the Clean Air Act, the Clean Air Act Amendments, the Clean Water Act, Superfund, and the Resource Conservation and Recovery Act. The requirements of these statutes and related state and local laws are continually changing due to the promulgation of new or revised laws and regulations and the results of judicial and agency proceedings. Compliance with such laws and regulations may require the Operating Companies to modify, supplement, abandon or replace facilities and may delay or impede construction and operation of facilities, all at costs which could be substantial. The Operating Companies expect that the impact of such costs would eventually be reflected in their respective rate schedules. Cleveland Electric and Toledo Edison plan to spend, during the period 1995-1999, $98,900,000 and $29,200,000, respectively, for pollution control facilities, including Clean Air Act Amendments compliance costs.

The Operating Companies believe that they are currently in compliance in all material respects with all applicable environmental laws and regulations, or to the extent that one or both of the Operating Companies may dispute the applicability or interpretation of a particular environmental law or regulation, the affected company has filed an appeal or has applied for permits, revisions to requirements, variances or extensions of deadlines.

Concerns have been raised regarding the possible health effects associated with electric and magnetic fields. Although scientific research as to such effects has yielded inconclusive results, additional studies are being conducted. If electric and magnetic fields are ultimately found to pose a health risk, the Operating Companies may be required to modify transmission and distribution lines or other facilities.

Air Quality Control

Under the Clean Air Act, the Ohio EPA has adopted emission limitations for particulate matter and sulfur dioxide for each of the Operating Companies' plants. The Clean Air Act provides for civil penalties of up to $25,000 per day for each violation of an emission limitation. The U.S. EPA has approved the Ohio EPA's emission limitations and the related state implementation plan except for some particulate matter emissions and certain sulfur dioxide emissions.

In November 1990, the Clean Air Act Amendments imposed more stringent restrictions on nitrogen oxide emissions and sulfur dioxide emissions beginning in 1995. See Note 4(a) for a description of the Operating Companies' compliance strategy, which was included in the agreement approved by the PUCO in February 1993 in connection with the Operating Companies' 1992 long-term forecast. The Clean Air Act Amendments also require studies to be conducted on the emission of certain potentially hazardous air pollutants which could lead to additional restrictions.

Global warming, or the "greenhouse effect", has been the subject of scientific study and debate within the United States and internationally. One area of study involves the effect on global warming of the emissions of gases such as those resulting from the burning of coal. Based on a 1992 United Nations treaty, the United States has developed a voluntary plan to reduce the emissions of certain gases thought to contribute to global warming to 1990 levels by the year 2000. The Operating Companies will work with the DOE and other utilities to develop a plan for limiting such emissions.

Water Quality Control

The Clean Water Act requires that power plants obtain permits under the NPDES program that contain certain effluent limitations (that is, limits on discharges of pollutants into bodies of water). It also requires the states to establish water quality standards which could result in more stringent effluent limitations. Violators of effluent limitations and water quality standards are subject to a civil penalty of up to $25,000 per day for each such violation.

The Operating Companies have received NPDES permit renewals from the Ohio EPA or have applied for such renewals for all of their power plants. In those situations in which a permit application is pending, the affected plant may continue to operate under the expired permit while such application is pending. Any violation of an NPDES permit is considered to be a violation of the Clean Water Act subject to the penalty discussed above.

The Clean Water Act permits thermal effluent limitations to be established for a facility which are less stringent than those which otherwise would apply if the owner can demonstrate that such less stringent limitations are sufficient to assure the protection and propagation of aquatic and other wildlife in the affected body of water. By 1978, the Operating Companies had submitted to the Ohio EPA such demonstrations for review with respect to their Ashtabula, Avon Lake, Lake Shore, Eastlake, Acme and Bay Shore plants. The Ohio EPA has taken no action on the submittals.

In 1990, the Ohio EPA issued revised water quality standards applicable to Lake Erie and waters of the State of Ohio. Based upon these revised water quality standards, the Ohio EPA placed additional effluent limitations in their most recent NPDES permits. The revised standards also may serve as the basis for more stringent effluent limitations in future NPDES permits. Such limitations could result in the installation of additional pollution control equipment and increased operating expenses. The Operating Companies are monitoring discharges at their plants to support their position that additional effluent limitations are not justified.

In April 1993, the U.S. EPA issued proposed rules for water quality standards applicable to all states abutting the Great Lakes, including Ohio. These states would be required to adopt state water quality standards and procedures consistent with the rules within two years of final publication. Preliminary reviews indicate that the cost of complying with these rules could be significant. However, the Operating Companies cannot determine what impact

these rules will have on their operations until such rules are issued in final form and are incorporated into Ohio regulations.

Waste Disposal

See "Outlook--Hazardous Waste Disposal Sites" in Management's Financial Analysis contained under Item 7 of this Report and Note 4(c) for a discussion of the Operating Companies' potential involvement in certain hazardous waste disposal sites, including those subject to Superfund. See "Operations--Nuclear Units" for a discussion concerning the disposal of nuclear waste.

The Resource Conservation and Recovery Act exempts certain fossil fuel combustion waste products, such as fly ash, from hazardous waste disposal requirements and requires the U.S. EPA to evaluate the need for future regulation. On August 9, 1994, the U.S. EPA issued its final regulatory determination that regulation of coal ash as a hazardous waste is unnecessary.

ELECTRIC RATES

General

Under Ohio law, rate base is the original cost less depreciation of a utility's total plant adjusted for certain items. The law permits the PUCO, in its discretion, to include construction work in progress in rate base under certain conditions.

Current Ohio law further provides that requested rates can be collected by a public utility, subject to refund, if the PUCO does not make a decision within 275 days after the rate request application is filed. If the PUCO does not make its final decision within 545 days, revenues collected thereafter are not subject to refund. A notice of intent to file an application for a rate increase cannot be filed before the issuance of a final order in any prior pending application for a rate increase or until 275 days after the filing of the prior application, whichever is earlier. The minimum period by which the notice of intent to file must precede the actual filing is 30 days. The test year for determining rates may not end more than nine months after the date the application for a rate increase is filed.

Under Ohio law, electric rates are adjusted every six months to reflect changes in fuel costs. The PUCO reviews such adjustments annually. Any difference between actual fuel costs during a six-month period and the fuel revenues recovered in that period is deferred and is taken into account in setting the fuel recovery factor for a subsequent six-month period.

Also, under Ohio law, municipalities may regulate rates charged by a utility, subject to appeal to the PUCO if not acceptable to the utility. If municipally fixed rates are accepted by the utility, such rates are binding on both parties for the specified term and cannot be changed by the PUCO. See "Operations--Competitive Conditions--Cleveland Electric" for information on a 1994 rate reduction ordinance in Garfield Heights.

See Note 7 and Management's Financial Analysis contained under Item 7 of this Report for information relating to the Rate Stabilization Program that was approved by the PUCO for the Operating Companies in October 1992 and other rate matters.

1995 Rate Requests

On March 17, 1995, the Operating Companies each notified the PUCO of their intent to file a request for a rate increase to be effective in 1996. Cleveland Electric's requested increase will be $82,800,000 in annual revenues and Toledo Edison's requested increase will be $34,800,000. The requested rates would result in an average increase of 4.9% in Cleveland Electric's existing rates and an average increase of 4.7% in Toledo Edison's existing rates.

The Operating Companies plan to freeze rates until at least 2002 if their rate requests are approved, although they are not precluded from requesting additional rate increases. This plan is premised on the Operating Companies obtaining full recovery of all costs including an acceptable rate of return on equity in order to continue to apply Statement of Financial Accounting Standard 71 ("SFAS 71") for financial reporting purposes. The Operating Companies plan to avoid the need for further rate increases through additional cost reductions, an enhanced marketing program and other efforts. The Operating Companies will periodically assess their continued compliance with SFAS 71 criteria and the appropriateness of continuing to record additional deferrals pursuant to the Rate Stabilization Program referred to above. They will modify their intended course of action as necessary to maintain compliance.

The rate increases are necessary to recover capital investment and increases in costs incurred since the Operating Companies' last rate cases, which were decided in January 1989, and to recover certain costs deferred since 1992. The amounts of the requested rate increases are lower than the authorized limits set forth in the Rate Stabilization Program. The additional cash resulting from the rate increases will strengthen Centerior's and the Operating Companies' financial and competitive positions.

OPERATIONS

Sales of Electricity

Kilowatt-hour sales by the Operating Companies follow a seasonal pattern marked by increased customer usage in the summer for air conditioning and in the winter for heating. Historically, Cleveland Electric has experienced its heaviest demand for electric service during the summer months because of a significant air conditioning load on its system and a relatively low amount of electric heating load in the winter. Toledo Edison, although having a significant electric heating load, has experienced in recent years its heaviest demand for electric service during the summer months because of heavy air conditioning usage.

The Centerior System's largest customer is a steel manufacturer which has two major steel producing facilities served by Cleveland Electric. Sales to these facilities accounted for 2.6% and 3.7% of the 1994 total electric operating revenues of Centerior Energy and Cleveland Electric, respectively. The loss of these facilities would reduce Centerior Energy's and Cleveland Electric's net income by about $27,000,000 based on 1994 sales levels.

The largest customer served by Toledo Edison is a major automobile manufacturer. Sales to this customer accounted for 1.6% and 4.4% of the 1994 total electric operating revenues of Centerior Energy and Toledo Edison, respectively. The loss of this customer would reduce Centerior Energy's and Toledo Edison's net income by about $17,000,000 based on 1994 sales levels.

Operating Statistics

For data on operating revenues by service category, electric sales by service category, customers by service category and electric energy generation for 1984 and 1990 through 1994, see the attached Pages F-25 and F-26 for Centerior Energy, F-49 and F-50 for Cleveland Electric and F-73 and F-74 for Toledo Edison.

Nuclear Units

The Operating Companies' generating facilities include, among others, three nuclear units owned or leased by the CAPCO Group--Perry Unit 1, Beaver Valley Unit 2 and Davis-Besse. These three units are in commercial operation. Cleveland Electric has responsibility for operating Perry Unit 1, Duquesne has responsibility for operating Beaver Valley Unit 2 and Toledo Edison has responsibility for operating Davis-Besse. Cleveland Electric and Toledo Edison own, respectively, 31.11% and 19.91% of Perry Unit 1, 24.47% and 1.65% of Beaver Valley Unit 2 and 51.38% and 48.62% of Davis-Besse. Cleveland Electric and Toledo Edison also lease, as joint lessees, an additional 18.26% of Beaver Valley Unit 2 as a result of a September 1987 sale and leaseback transaction (see Note 2).

Davis-Besse was placed in commercial operation in 1977, and its operating license expires in 2017. Perry Unit 1 and Beaver Valley Unit 2 were placed in commercial operation in 1987, and their operating licenses expire in 2026 and 2027, respectively.

In January 1989, the PUCO approved nuclear plant performance standards for the Operating Companies based on rolling three-year industry averages of availability for pressurized water reactors and for boiling water reactors over the 1988-1998 period. Availability is the ratio of the number of hours a unit is available to generate electricity (whether or not the unit is operated) to the number of hours in the period, expressed as a percentage. The three-year availability averages of the Operating Companies' nuclear units are compared against the industry averages for the same three-year period with a resultant penalty or banked benefit. If the industry performance standards are not met, a penalty would be incurred which would require the Operating Companies to refund incremental replacement power costs to customers through

the semiannual fuel cost rate adjustment. However, if the performance of the Operating Companies' nuclear units exceeds the industry standards, a banked benefit results which can be used to offset disallowances of incremental replacement power costs should future performance be below industry standards.

The relevant industry standards for the 1992-1994 period (as of November 30, 1994) are 79.6% for pressurized water reactors such as Davis-Besse and Beaver Valley Unit 2 and 73% for boiling water reactors such as Perry Unit 1. The 1992-1994 combined availability average for Davis-Besse and Beaver Valley Unit 2 was 89.5% and the availability average for Perry Unit 1 was 57.1%. At December 31, 1994, the total banked benefit for the Operating Companies is estimated to be between $20,000,000 and $22,000,000.

All three nuclear units have received generally favorable evaluations from the NRC in their most recent SALP reviews, with Davis-Besse receiving the best possible scores. Each of the functional areas evaluated is rated according to three performance categories, with category 1 indicating performance substantially exceeding regulatory requirements and that reduced NRC attention may be appropriate; category 2 indicating performance above that needed to meet regulatory requirements and that NRC attention may be maintained at normal levels; and category 3 indicating performance does not significantly exceed that needed to meet minimal regulatory requirements and that NRC attention should be increased above normal levels.

The most recent review periods and SALP review scores for Beaver Valley Unit 2, Perry Unit 1 and Davis-Besse are:

	Beaver Valley Unit 2	Perry Unit 1	Davis-Besse
SALP Review Period	6/14/92-11/27/93	2/1/93-1/7/95	7/1/93-1/21/95
Operations	1	2	1
Engineering	2	2	1
Maintenance	2	2	1
Plant Support	1	2	1

In 1980, Congress passed the Low-Level Radioactive Waste Policy Act which requires that the disposal site for low-level radioactive waste will be within the boundaries of the state where such waste was generated. The Act encourages states to form compacts among themselves to develop regional disposal facilities. Failure by a state or compact to begin implementation of a program could result in access denial to the two facilities currently accepting low-level radioactive waste. Ohio is part of the Midwest Compact and has responsibility for siting and constructing a disposal facility, but, to date, has made little progress. Therefore, effective July 1994, the Operating Companies are no longer able to ship low-level radioactive waste produced at their nuclear plants to offsite disposal facilities. The Operating Companies' ability to ship offsite in the future depends on whether the State of Ohio develops a low-level radioactive waste disposal facility within the next several years. As an interim solution, the Operating Companies have constructed storage facilities to house the waste at each nuclear site.

Off-site disposal of spent nuclear fuel is unavailable, but the CAPCO Group companies have contracts with the DOE which provide for the future acceptance of spent fuel for disposal by the Federal government. Pursuant to the Nuclear Waste Policy Act of 1982, the Federal government has indicated it will begin accepting spent fuel from utilities by the year 2010. On-site storage capacity at Davis-Besse, Perry Unit 1 and Beaver Valley Unit 2 should be sufficient through 1996, 2013 and 2011, respectively. An additional on-site storage facility is being constructed at Davis-Besse to provide storage capacity through 2017. Any additional storage capacity needed at Perry Unit 1 and Beaver Valley Unit 2 for the period until the government accepts the fuel can, likewise, be provided by constructing an additional on-site storage facility.

See Note 4(b) for a discussion of the write-off of Perry Unit 2, and see "Outlook--Nuclear Operations" in Management's Financial Analysis contained under Item 7 of this Report for a discussion of potential risks facing Centerior and the Operating Companies as owners of nuclear generating units.

Competitive Conditions

General. The Operating Companies compete in their respective service areas with suppliers of natural gas to satisfy customers' energy needs with regard to heating and appliance usage. The Operating Companies also are engaged in competition to a lesser extent with suppliers of oil and liquefied natural gas for heating purposes and with suppliers of cogeneration equipment. One competitor provides steam for heating purposes and provides chilled water for cooling purposes in certain areas of downtown Cleveland.

The Operating Companies also compete with municipally owned electric systems within their respective service areas. Several communities have evaluated municipalization of electric service and decided to continue service from the Operating Companies. Officials in other communities have indicated an interest in evaluating the municipalization issue.

The Operating Companies face continuing competition from locations outside their service areas which are promoted by governmental and private agencies in attempts to influence potential and existing commercial and industrial customers to locate in their respective areas.

The Operating Companies also periodically compete with other producers of electricity for sales to electric utilities which are in the market for bulk power purchases. The Operating Companies have interconnections with other electric utilities (see "Item 2. Properties--General") and have a transmission system capable of transmitting ("wheeling") power between the Midwest and the East.

Cleveland Electric. Located within Cleveland Electric's service area are two municipally owned electric systems. Cleveland Electric supplies a small portion of those systems' power needs at wholesale rates.

One of those systems, CPP, is operated by the City of Cleveland in competition with Cleveland Electric. CPP is primarily an electric distribution system which currently supplies electric power in approximately 50% of the City's geographical area (expected to increase to 100% by the end of 1999) and to approximately 30% (about 66,000) of the electric consumers in the City--equal to about 9% of all customers served by Cleveland Electric. CPP's kilowatt-hour sales and revenues are equal to about 5% of Cleveland Electric's kilowatt-hour sales and revenues. Much of the area served by CPP overlaps that of Cleveland Electric. For all classes of customers, Cleveland Electric's rates are higher than CPP's rates due largely to CPP's exemption from taxation, the lower-cost financing available to CPP, the continued availability to CPP of lower cost power through short-term power purchases and CPP's access to cheaper governmental power.

Cleveland Electric makes power available to CPP on a wholesale basis, subject to FERC regulation. In 1994, Cleveland Electric directly and through AMP-Ohio provided about 1% of CPP's energy requirements. The balance of CPP's power is purchased from other sources and wheeled over Cleveland Electric's transmission system. In cases currently pending, the FERC has been asked to determine whether Cleveland Electric is obligated to provide an additional interconnection with CPP and to rule on Cleveland Electric's request for an increase in rates for power and services provided to CPP. Cleveland Electric believes that it is entitled to a higher level of compensation for the power and the services it provides because the rates currently paid by CPP do not adequately cover the cost of providing such power and services.

CPP is constructing new transmission and distribution facilities extending into eastern portions of Cleveland and plans to expand to western portions of Cleveland, both of which now are served exclusively by Cleveland Electric. CPP's expansion has resulted in a reduction in Cleveland Electric's annual net income by about $4,000,000 in 1993 and an additional $3,000,000 in 1994. Cleveland Electric estimates that its net income will continue to be reduced by an additional $4,000,000-$5,000,000 each year in the 1995-1999 period because of CPP's expansion. Despite CPP's expansion efforts, Cleveland Electric has been successful in retaining most of the large industrial and commercial customers in the expansion areas by providing economic incentives in exchange for sole-supplier contracts. Cleveland Electric has similar contracts with customers in other parts of its service area. Approximately 90% of Cleveland Electric's industrial revenues under contract will not be up for renewal until 1997 or later. As these contracts expire, Cleveland Electric expects to renegotiate them and retain the customers. In addition, an increasing number of CPP customers are converting back to Cleveland Electric service. However, competition for such customers will continue. In March 1995, one of Cleveland Electric's large commercial customers, comprising medical and educational institutions, indicated that it intends to transfer to CPP service when its contract with Cleveland Electric terminates in 1996. The loss of this customer to CPP would reduce Centerior's and Cleveland Electric's net income by about $5,000,000 based on 1994 sales levels.

In March 1994, the City Council of Garfield Heights, a suburb of Cleveland, passed an ordinance calling for a 30% reduction in rates for Cleveland

Electric's customers in that city. Cleveland Electric appealed that ordinance to the PUCO. On January 23, 1995, the staff of the PUCO issued its report on the matter concluding that a rate reduction for Garfield Heights is not warranted. The PUCO will hold public hearings in March 1995 prior to ruling on the matter. The potential impact of the rate reduction on Cleveland Electric's annual revenues is $5,500,000.

Currently, one commercial customer and one industrial customer of Cleveland Electric have cogeneration installations.

Toledo Edison. Located wholly or partly within Toledo Edison's service area are six rural electric cooperatives, five of which are supplied with power, transmitted in some cases over Toledo Edison's facilities, by Buckeye Power, Inc. (an affiliate of a number of Ohio rural electric cooperatives) and the sixth is supplied by Toledo Edison.

Also located within Toledo Edison's service area are 16 municipally owned electric distribution systems, three of which are supplied by other electric systems. Toledo Edison provides a portion of the power purchased by the other 13 municipalities at wholesale rates through a contract with AMP-Ohio that expires in 2009. Rates under this agreement are permitted to increase annually to compensate for increased costs of operation. Less than 2% of Toledo Edison's total electric operating revenues in 1994 were derived from sales under the AMP-Ohio contract.

In October 1989, the City of Toledo established an Electric Franchise Review Committee to (i) study Toledo Edison's franchise agreement with the City to determine whether alternate energy sources may be utilized and (ii) investigate the feasibility of establishing a municipal electric system within the City of Toledo. In November 1993, the City approved a non-exclusive franchise with Toledo Edison which runs through the end of 1998. Although the Electric Franchise Review Committee is not currently actively investigating the formation of a municipal system, the City could renew such efforts at any time.

On January 3, 1995, the City of Clyde, which operates its own municipal electric system, passed ordinances to force Toledo Edison to remove most equipment from within the City's borders and to prevent any residential and commercial customers within the City from obtaining service from Toledo Edison. The City subsequently asked the PUCO to authorize the removal of Toledo Edison equipment under the Miller Act. The Miller Act is an Ohio statute which provides that a municipality cannot force a utility to vacate a city without demonstrating that such action is in the public interest and obtaining the approval of the PUCO. Toledo Edison has challenged the City of Clyde's Miller Act proceeding before the PUCO and has filed an action in the Court of Appeals in Sandusky County, Ohio to challenge the City's ordinance prohibiting customers from using Toledo Edison service. Toledo Edison currently serves approximately 400 customers within the City of Clyde.

No commercial customer of Toledo Edison now operates a cogeneration unit.

Fuel Supply

Generation by type of fuel for 1994 was 67% coal-fired and 33% nuclear for Cleveland Electric; 49% coal-fired and 51% nuclear for Toledo Edison; and 61% coal-fired and 39% nuclear for the Centerior System.

Coal. In 1994, Cleveland Electric and Toledo Edison burned 5,304,000 tons and 1,990,000 tons of coal, respectively, for electric generation. Each utility normally maintains a reserve supply of coal sufficient for about 30 days of normal operations. On February 1, 1995, this reserve was about 24 days for plants operated by Cleveland Electric, 31 days for the plant operated by Toledo Edison and 50 days for the Mansfield Plant, which is operated by Pennsylvania Power.

In 1994, about 49% of Cleveland Electric's coal requirements were purchased under long-term contracts, with the longest remaining term being almost nine years. In most cases, these contracts provide for adjusting the price of the coal on the basis of changes in coal quality and mining costs. The sulfur content of the coal purchased under these contracts ranges from less than 1% to about 4%. The balance of Cleveland Electric's coal was purchased on the spot market with sulfur content ranging from less than 1% to 3.5%.

In 1994, about 61% of Toledo Edison's coal requirements were purchased under long-term contracts, with the longest remaining term being almost six years. In most cases, these contracts provide for adjusting the price of the coal on the basis of changes in coal quality and mining costs. The sulfur content of the coal purchased under these contracts ranges from less than 1% to 4%.

One of Cleveland Electric's long-term coal supply contracts is with Ohio Valley. Cleveland Electric has agreed to pay Ohio Valley certain amounts to cover Ohio Valley's costs regardless of the amount of coal actually delivered. Included in those costs are amounts sufficient to service certain long-term debt and lease obligations incurred by Ohio Valley. If the coal sales agreement is terminated for any reason, Cleveland Electric must assume certain of Ohio Valley's debt and lease obligations and may incur other expenses including mine closing costs, if necessary. At December 31, 1994, the principal amount of debt and termination values of leased property covered by Cleveland Electric's agreement was $21,309,000, while the unfunded costs of closing this mine, as estimated by Ohio Valley, were $54,000,000. The coal supply agreement with Ohio Valley is scheduled to continue until September 1997. Cleveland Electric expects that Ohio Valley revenues from sales of coal will continue to be sufficient for Ohio Valley to meet its debt and lease obligations and mine closing costs over the life of the contract.

The CAPCO Group companies, including the Operating Companies, have a long-term contract with Quarto and Consol for the supply of about 75%-85% of the annual coal needs of the Mansfield Plant. The contract is scheduled to run through at least the end of 1999, and the price of coal is adjustable to reflect changes in labor, materials, transportation and other costs. The CAPCO Group companies have guaranteed, severally and not jointly, the debt and lease obligations incurred by Quarto to develop, equip and operate two of the mines which supply the Mansfield Plant. At December 31, 1994, the total dollar

amount of Quarto's debt and lease obligations guaranteed by Cleveland Electric was $28,698,000 and by Toledo Edison was $16,772,000. Centerior, Cleveland Electric and Toledo Edison expect that Quarto revenues from sales of coal to the CAPCO Group companies will continue to be sufficient for Quarto to meet its debt and lease obligations.

The Operating Companies' least cost plan for complying with the Clean Air Act Amendments, which was included in the agreement approved by the PUCO in February 1993 in connection with the Operating Companies' 1992 long-term forecast, calls for greater use of low-sulfur coal and less use of high-sulfur coal. Some of the low-sulfur coal required to comply with Phase 1 of the Clean Air Act Amendments was contracted for in 1992. Additional supplies of low-sulfur coal will be purchased in 1997.

Nuclear. The acquisition and utilization of nuclear fuel involves six distinct steps: (i) supply of uranium oxide raw material, (ii) conversion to uranium hexafluoride, (iii) enrichment, (iv) fabrication into fuel assemblies, (v) utilization as fuel in a nuclear reactor and (vi) storing or disposing of spent fuel. The Operating Companies have inventories of raw material sufficient to provide nuclear fuel through 1996 for the operation of their nuclear generating units and have contracts for fabrication services for all of that fuel. The CAPCO Group companies have a 30-year contract with the USEC which will supply all of the needed enrichment services for their nuclear units' fuel supply through 1995. Beyond 1995, the amount of enrichment services under the USEC contract varies by CAPCO Group company, with Cleveland Electric's and Toledo Edison's enrichment services reduced to 70% in 1996-1999 and reduced to 0% in 2000 and beyond. The additional required enrichment services are available. Substantial additional fuel will have to be obtained in the future over the remaining useful lives of the units. There is a plentiful supply of uranium oxide raw material to meet the industry's nuclear fuel needs.

Oil. The Operating Companies each have adequate supplies of oil and fuel for their oil-fired electric generating units which are used primarily as reserve and peaking capacity.

EXECUTIVE OFFICERS OF THE REGISTRANTS AND THE SERVICE COMPANY

Set forth below are the names, ages as of March 15, 1995, and business experience during the past five years (effective dates of positions in parentheses) of the executive officers of Centerior Energy, the Service Company, Cleveland Electric and Toledo Edison. Positions currently held are designated with an asterisk (*).

	Business Experience			
Name (Age)	Centerior Energy	Service Company	Cleveland Electric	Toledo Edison
Robert J. Farling (58)	*Chairman of the Board and Chief Executive Officer (March 1992) *President (October 1988)	*Chairman of the Board and Chief Executive Officer (March 1992) *President (July 1988)	*Chairman of the Board and Chief Executive Officer (February 1989 to April 1990; July 1993)	*Chairman of the Board and Chief Executive Officer (October 1988 to April 1990; July 1993)
Murray R. Edelman (55)	*Executive Vice President (July 1988)	*Executive Vice President-Operations & Engineering (July 1993) Executive Vice President-Power Generation (April 1990)	*President (November 1993)	*Vice Chairman (November 1993) President (July 1988)

Name (Age)	Business Experience			
	Centerior Energy	Service Company	Cleveland Electric	Toledo Edison
Fred J. Lange, Jr. (45)	*Senior Vice President (July 1993) Senior Vice President-Legal, Human & Corporate Affairs (March 1992) Vice President-Legal & Corporate Affairs (April 1990)	*Senior Vice President-Fossil & Transmission and Distribution Operations (July 1993) Senior Vice President-Legal, Human & Corporate Affairs (March 1992) Vice President-Legal & Corporate Affairs (April 1990) General Attorney and Senior Director of Governmental Affairs (July 1989)	*Vice President (April 1990)	*President (November 1993) Vice President (April 1990)
Donald C. Shelton (61)		*Senior Vice President-Nuclear and Vice President-Nuclear-Perry (January 1995) Senior Vice President-Nuclear (July 1993) Vice President-Nuclear-Davis-Besse (April 1990)		Vice President-Nuclear (August 1986)

	Business Experience			
Name (Age)	Centerior Energy	Service Company	Cleveland Electric	Toledo Edison
Jacquita K. Hauserman (52)		*Vice President-Customer Support (July 1993) Vice President-Customer Service & Community Affairs (April 1990)	*Vice President (November 1993) Vice President-Administration (October 1988)	
Gary R. Leidich (44)	*Vice President (July 1993)	*Vice President-Finance & Administration (July 1993) Director-Human Resources Dept. (August 1991) Director-System Planning Engineering Dept. (December 1987)	*Vice President & Chief Financial Officer (July 1993)	*Vice President & Chief Financial Officer (July 1993)

Name (Age)	Business Experience: Centerior Energy	Service Company	Cleveland Electric	Toledo Edison
Terrence G. Linnert (48)	*Vice President (July 1993)	*Vice President-Legal & Governmental Affairs and General Counsel (July 1993) Vice President-Legal and General Counsel (March 1992) General Counsel and Director-Legal Services Dept. (May 1990) General Counsel (July 1989)	*Vice President (July 1993)	*Vice President (July 1993)
David L. Monseau (54)		*Vice President-Transmission & Distribution Operations (April 1990)		Vice President-Customer Operations (September 1987)

Name (Age)	Centerior Energy	Business Experience Service Company	Cleveland Electric	Toledo Edison
John P. Stetz (49)		*Vice President- Nuclear-Davis-Besse (July 1994) Northeast Utilities: Vice President- Connecticut Yankee Nuclear Power Station (October 1993) Station Director- Connecticut Yankee Nuclear Power Station (September 1990) Superintendent-Unit 1 Millstone Power Station (May 1985)		
Al R. Temple (49)		*Vice President- Sales & Marketing (February 1994) WMX Technologies, Inc.: Alliance Executive (July 1992) Vice President/ General Manager, Midwest Region (April 1991) Director of Marketing, Chemical Waste Management (June 1989)		

Name (Age)	Business Experience			
	Centerior Energy	Service Company	Cleveland Electric	Toledo Edison
E. Lyle Pepin (53)	*Controller and Assistant Secretary (November 1994) Secretary (February 1986)	*Controller and Assistant Secretary (November 1994) Secretary (April 1986)	*Controller and Assistant Secretary (November 1994) Secretary (October 1988)	*Controller and Assistant Secretary (November 1994) Secretary (October 1988)
David M. Blank (46)	*Treasurer (November 1994)	*Treasurer (November 1994) *Director of Strategic Planning (October 1993) Director of Rates & Corporate Planning (May 1990) Director of Rates Administration & Economic Analysis (May 1986)	*Treasurer (November 1994)	*Treasurer (November 1994)
Janis T. Percio (42)	*Secretary (November 1994) Assistant Secretary (April 1986)	*Secretary (November 1994) Assistant Secretary (April 1986)	*Secretary (November 1994) Assistant Secretary (October 1982)	*Secretary (November 1994) Assistant Secretary (April 1986)

All of the executive officers of Centerior Energy, the Service Company, Cleveland Electric and Toledo Edison are elected annually for a one-year term by the Board of Directors of Centerior, the Service Company, Cleveland Electric or Toledo Edison, as the case may be.

No family relationship exists among any of the executive officers and directors of any of the Centerior System companies.

Item 2. Properties

GENERAL

The Centerior System

The wholly owned, jointly owned and leased electric generating facilities of the Operating Companies in commercial operation as of February 28, 1995 provide the Centerior System with a net demonstrated capability of 5,980,000 kilowatts during the winter. These facilities include 20 generating units (3,634,000 kilowatts) at seven fossil-fired steam electric generation stations; three nuclear generating units (1,856,000 kilowatts); a 351,000 kilowatt share of the Seneca Plant; seven combustion turbine generating units (135,000 kilowatts) and one diesel generator (4,000 kilowatts). Two fossil-fired generating units (320,000 kilowatts) were placed on cold standby status in 1993. All of the Centerior System's generating facilities are located in Ohio and Pennsylvania.

The Centerior System's net 60-minute peak load of its service area for 1994 was 5,291,000 kilowatts and occurred on July 20. The net seasonal capability at the time of the 1994 peak load was 6,226,000 kilowatts. The Centerior System's 1995 native peak load is forecasted to be 5,180,000 kilowatts, after demand-side management considerations. The net seasonal capability expected to be available to serve the Centerior System's 1995 peak is 5,924,000 kilowatts. Over the 1995-1997 period, Centerior Energy forecasts its capacity margins at the time of the projected Centerior System peak loads to range from 11% to 13%, excluding the capacity on cold standby.

Each Operating Company owns the electric transmission and distribution facilities located in its respective service area. Cleveland Electric and Toledo Edison are interconnected by 345 kV transmission facilities, some portions of which are owned and used by Ohio Edison. The Operating Companies have a long-term contract with the CAPCO Group companies, including Ohio Edison, relating to the use of these facilities. These interconnection facilities provide for the interchange of power between the two Operating Companies. The Centerior System is interconnected with Ohio Edison, Ohio Power, Penelec and Detroit Edison.

Cleveland Electric

The wholly owned, jointly owned and leased electric generating facilities of Cleveland Electric in commercial operation as of February 28, 1995 provide a net demonstrated capability of 4,148,000 kilowatts during the winter. These

facilities include 16 generating units (2,709,000 kilowatts) at five fossil-fired steam electric generation stations; its share of three nuclear generating units (1,026,000 kilowatts); a 351,000 kilowatt share of the Seneca Plant; two combustion turbine generating units (58,000 kilowatts) and one diesel generator (4,000 kilowatts). One fossil-fired generating unit (245,000 kilowatts) was placed on cold standby status in 1993. All of Cleveland Electric's generating facilities are located in Ohio and Pennsylvania.

The net 60-minute peak load of Cleveland Electric's service area for 1994 was 3,740,000 kilowatts and occurred on July 20. The net seasonal capability at the time of the 1994 peak was 4,497,000 kilowatts. Cleveland Electric's 1995 native peak load is forecasted to be 3,700,000 kilowatts, after demand-side management considerations. The net seasonal capability expected to be available to serve Cleveland Electric's 1995 peak is 4,273,000 kilowatts. Over the 1995-1997 period, Cleveland Electric forecasts its capacity margins at the time of its projected peak loads to range from 12% to 13%, excluding the capacity on cold standby.

Cleveland Electric owns the facilities located in the area it serves for transmitting and distributing power to all its customers. Cleveland Electric has interconnections with Ohio Edison, Ohio Power and Penelec. The interconnections with Ohio Edison provide for the interchange of electric power with the other CAPCO Group companies and for transmission of power from the tenant-in-common owned or leased CAPCO Group generating units as well as for the interchange of power with Toledo Edison. The interconnection with Penelec provides for transmission of power from Cleveland Electric's share of the Seneca Plant. In addition, these interconnections provide the means for the interchange of electric power with other utilities.

Cleveland Electric has interconnections with each of the municipal systems operating within its service area.

Toledo Edison

The wholly owned, jointly owned and leased electric generating facilities of Toledo Edison in commercial operation as of February 28, 1994 provide a net demonstrated capability of 1,832,000 kilowatts during the winter. These facilities include six generating units (925,000 kilowatts) at three fossil-fired steam electric generation stations; its share of three nuclear generating units (830,000 kilowatts) and five combustion turbine generating units (77,000 kilowatts). One fossil-fired generating unit (75,000 kilowatts) was placed on cold standby status in 1993. All of Toledo Edison's generating facilities are located in Ohio and Pennsylvania.

The net 60-minute peak load of Toledo Edison's service area for 1994 was 1,620,000 kilowatts and occurred on June 16. The net seasonal capability at the time of the 1994 peak was 1,729,000 kilowatts. Toledo Edison's 1995 native peak load is forecasted to be 1,510,000 kilowatts, after demand-side management considerations. The net seasonal capability expected to be available to serve Toledo Edison's 1995 peak is 1,651,000 kilowatts. Over the 1995-1997 period, Toledo Edison forecasts its capacity margins at the time of

its projected peak loads to range from 5% to 9%, excluding the capacity on cold standby.

Toledo Edison owns the facilities located in the area it serves for transmitting and distributing power to all its customers. Toledo Edison has interconnections with Ohio Edison, Ohio Power and Detroit Edison. The interconnection with Ohio Edison provides for the interchange of electric power with the other CAPCO Group companies and for transmission of power from the tenant-in-common owned or leased CAPCO Group generating units as well as for the interchange of power with Cleveland Electric. In addition, these interconnections provide the means for the interchange of electric power with other utilities.

Toledo Edison has interconnections with each of the municipal systems operating within its service area.

TITLE TO PROPERTY

The generating plants and other principal facilities of the Operating Companies are located on land owned in fee by them, except as follows:

(1) Cleveland Electric and Toledo Edison lease from others for a term of about 29-1/2 years starting on October 1, 1987 undivided 6.5%, 45.9% and 44.38% tenant-in-common interests in Units 1, 2 and 3, respectively, of the Mansfield Plant located in Shippingport, Pennsylvania. Cleveland Electric and Toledo Edison lease from others for a term of about 29-1/2 years starting on October 1, 1987 an 18.26% undivided tenant-in-common interest in Beaver Valley Unit 2 located in Shippingport, Pennsylvania. Cleveland Electric and Toledo Edison own another 24.47% interest and 1.65% interest, respectively, in Beaver Valley Unit 2 as a tenant-in-common. Cleveland Electric and Toledo Edison continue to own as a tenant-in-common the land upon which the Mansfield Plant and Beaver Valley Unit 2 are located, but have leased to others certain portions of that land relating to the above-mentioned generating unit leases.

(2) Most of the facilities of Cleveland Electric's Lake Shore Plant are situated on artificially filled land, extending beyond the natural shoreline of Lake Erie as it existed in 1910. As of December 31, 1994, the cost of Cleveland Electric's facilities, other than water intake and discharge facilities, located on such artificially filled land aggregated approximately $107,221,000. Title to land under the water of Lake Erie within the territorial limits of Ohio (including artificially filled land) is in the State of Ohio in trust for the people of the State for the public uses to which it may be adapted, subject to the powers of the United States, the public rights of navigation, water commerce and fishery and the rights of upland owners to wharf out or fill to make use of the water. The State is required by statute, after appropriate proceedings, to grant a lease to an upland owner, such as Cleveland Electric, which erected and maintained facilities on such filled land prior to October 13, 1955. Cleveland Electric does not have such a lease from the State with respect to the artificially filled land on which its Lake

Shore Plant facilities are located, but Cleveland Electric's position, on advice of counsel for Cleveland Electric, is that its facilities and occupancy may not be disturbed because they do not interfere with the free flow of commerce in navigable channels and constitute (at least in part) and are on land filled pursuant to the exercise by it of its property rights as owner of the land above the shoreline adjacent to the filled land. Cleveland Electric holds permits, under Federal statutes relating to navigation, to occupy such artificially filled land.

(3) The facilities of Cleveland Electric's Seneca Plant in Warren County, Pennsylvania, are located on land owned by the United States and occupied by Cleveland Electric and Penelec pursuant to a license issued by the FERC for a 50-year period starting December 1, 1965 for the construction, operation and maintenance of a pumped-storage hydroelectric plant.

(4) The water intake and discharge facilities at the electric generating plants of Cleveland Electric and Toledo Edison located along Lake Erie, the Maumee River and the Ohio River are extended into the lake and rivers under their property rights as owners of the land above the water line and pursuant to permits under Federal statutes relating to navigation.

(5) The transmission systems of the Operating Companies are located on land, easements or rights-of-way owned by them. Their distribution systems also are located, in part, on interests in land owned by them, but, for the most part, their distribution systems are located on lands owned by others and on streets and highways. In most cases, permission has been obtained from the apparent owner of the property or, if the distribution system is located on streets and highways, from the apparent owner of the abutting property. Their electric underground transmission and distribution systems are located, for the most part, in public streets. The Pennsylvania portions of the main transmission lines from the Seneca Plant, the Mansfield Plant and Beaver Valley Unit 2 are not owned by Cleveland Electric or Toledo Edison.

All Cleveland Electric and Toledo Edison properties, with certain exceptions, are subject to the lien of their respective mortgages.

The fee titles which Cleveland Electric and Toledo Edison acquire as tenant-in-common owners, and the leasehold interests they have as joint lessees, of certain generating units do not include the right to require a partition or sale for division of proceeds of the units without the concurrence of all the other owners and their respective mortgage trustees and the trustees under Cleveland Electric's and Toledo Edison's mortgages.

Item 3. Legal Proceedings

Proceedings Regarding an Attempt by the City of Clyde, Ohio to Remove Toledo Edison. See "Item 1. Business--Operations--Competitive Conditions--Toledo Edison".

Proceedings before the PUCO Regarding Actions by the City of Garfield Heights, Ohio to Reduce Cleveland Electric's Rates within the City. See "Item 1. Business--Operations--Competitive Conditions--Cleveland Electric".

Proceedings before the FERC Regarding the Proposed Merger of the Operating Companies. See "Item 1. Business--Merger of the Operating Companies".

Proceedings before the PUCO Regarding the Requests for Rate Increases to be Filed by the Operating Companies. See "Item 1. Business--Electric Rates--1995 Rate Requests".

Westinghouse Lawsuit. In April 1991, the CAPCO Group companies filed a lawsuit against Westinghouse in the United States District Court for the Western District of Pennsylvania. The suit alleges that six steam generators supplied by Westinghouse for Beaver Valley Power Station Units 1 and 2 contain serious defects, particularly defects causing tube corrosion and cracking. Steam generator maintenance costs have increased due to these defects and will likely continue to increase. The condition of the steam generators is being monitored closely. If the corrosion and cracking continue, replacement of the steam generators could be required earlier than their 40-year design life. The suit seeks monetary and corrective relief. On September 12, 1994, a jury trial began. On October 24, 1994, the court dismissed four of the five claims against Westinghouse, leaving only a fraud claim. On December 6, 1994, the jury rendered a verdict in favor of Westinghouse on the fraud claim. The CAPCO Group companies have appealed the decision to the United States Court of Appeals for the Third Circuit. The Operating Companies believe that the outcome of this lawsuit will not have a materially adverse effect on their financial positions or results of operation.

Item 4. Submission of Matters to a Vote of Security Holders

CENTERIOR ENERGY, CLEVELAND ELECTRIC AND TOLEDO EDISON

None.

PART II

Item 5. Market for Registrants' Common Equity and Related Stockholder Matters

The information regarding common stock prices and number of share owners required by this Item is not applicable to Cleveland Electric or Toledo Edison because all of their common stock is held solely by Centerior Energy.

Market Information

Centerior Energy's common stock is traded on the New York, Chicago and Pacific Stock Exchanges. The quarterly high and low prices of Centerior common stock (as reported on the composite tape) in 1993 and 1994 were as follows:

	1993		1994	
	High	Low	High	Low
1st Quarter	$20	$18-5/8	$13-3/8	$10-5/8
2nd Quarter	19-7/8	17-3/8	11-3/4	9-7/8
3rd Quarter	18-7/8	17-3/8	10-5/8	8-7/8
4th Quarter	17-7/8	12	9-1/2	8

Share Owners

As of March 6, 1995, Centerior Energy had 147,358 common stock share owners of record.

Dividends

See Note 14 to Centerior's Financial Statements for quarterly dividend payments in the last two years. Future dividend action by Centerior's Board of Directors will continue to be decided on a quarter-to-quarter basis after the evaluation of financial results, potential earning capacity and cash flow.

At December 31, 1994, Centerior Energy had a retained earnings deficit of $438 million and capital surplus of $1.963 billion, resulting in an overall surplus of $1.525 billion that was available to pay dividends under Ohio law. Any current period earnings in 1995 will increase surplus under Ohio law. See Note 11(b) for discussions of dividend restrictions affecting Cleveland Electric and Toledo Edison.

Dividends paid in 1994 on each of the Operating Companies' outstanding series of preferred stock were fully taxable.

Item 6. Selected Financial Data

CENTERIOR ENERGY

The information required by this Item is contained on Pages F-25 and F-26 attached hereto.

CLEVELAND ELECTRIC

The information required by this Item is contained on Pages F-49 and F-50 attached hereto.

TOLEDO EDISON

The information required by this Item is contained on Pages F-73 and F-74 attached hereto.

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

CENTERIOR ENERGY

The information required by this Item is contained on Pages F-3 through F-7 attached hereto.

CLEVELAND ELECTRIC

The information required by this Item is contained on Pages F-28 through F-32 attached hereto.

TOLEDO EDISON

The information required by this Item is contained on Pages F-52 through F-56 attached hereto.

Item 8. Financial Statements and Supplementary Data

CENTERIOR ENERGY

The information required by this Item is contained on Pages F-2 and F-8 through F-24 attached hereto.

CLEVELAND ELECTRIC

The information required by this Item is contained on Pages F-27 and F-33 through F-48 attached hereto.

TOLEDO EDISON

The information required by this Item is contained on Pages F-51 and F-57 through F-72 attached hereto.

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

CENTERIOR ENERGY, CLEVELAND ELECTRIC AND TOLEDO EDISON

None.

PART III

Item 10. Directors and Executive Officers of the Registrants

CENTERIOR ENERGY

The information required by this Item for Centerior regarding directors is incorporated herein by reference to Pages 4 through 8 and Page 23 of Centerior's definitive proxy statement dated March 14, 1995. Reference is also made to "Executive Officers of the Registrants and the Service Company" in Part I of this Report for information regarding the executive officers of Centerior Energy.

CLEVELAND ELECTRIC

Set forth below are the name and other directorships held, if any, of each director of Cleveland Electric. The year in which the director was first elected to Cleveland Electric's Board of Directors is set forth in parenthesis. Reference is made to "Executive Officers of the Registrants and the Service Company" in Part I of this Report for information regarding the directors and executive officers of Cleveland Electric. The directors received no remuneration in their capacity as directors.

Robert J. Farling*
Mr. Farling is a director of National City Bank. (1986)

Murray R. Edelman
Mr. Edelman is a director of Society Bank & Trust and Society National Bank. (1993)

Fred J. Lange, Jr.
(1993)

*Also a director of Centerior Energy and the Service Company.

TOLEDO EDISON

Set forth below are the name and other directorships held, if any, of each director of Toledo Edison. The year in which the director was first elected to Toledo Edison's Board of Directors is set forth in parenthesis. Reference is made to "Executive Officers of the Registrants and the Service Company" in Part I of this Report for information regarding the directors and the executive officers of Toledo Edison. The directors received no remuneration in their capacity as directors.

Robert J. Farling*
Mr. Farling is a director of National City Bank. (1988)

Murray R. Edelman
Mr. Edelman is a director of Society Bank & Trust and Society National Bank. (1993)

Fred J. Lange, Jr.
(1993)

*Also a director of Centerior Energy and the Service Company.

Item 11. Executive Compensation

CENTERIOR ENERGY, CLEVELAND ELECTRIC AND TOLEDO EDISON

The information required by this Item for Centerior is incorporated herein by reference to the information concerning compensation of directors on Page 9 and the information concerning compensation of executive officers, stock option transactions, long-term incentive awards and pension benefits on Pages 29 through 32 of Centerior's definitive proxy statement dated March 14, 1995. The named executive officers for Centerior are included for Cleveland Electric and Toledo Edison regardless of whether they were officers of Cleveland Electric or Toledo Edison because they were key policymakers for the Centerior System in 1994.

Item 12. Security Ownership of Certain Beneficial Owners and Management

CENTERIOR ENERGY

The following table sets forth the beneficial ownership of Centerior common stock by individual directors of Centerior, the named executive officers and all directors and executive officers of Centerior Energy and the Service Company as a group as of February 28, 1995:

Name of Beneficial Owner	Number of Common Shares Owned (1)
Richard P. Anderson	2,071
Albert C. Bersticker	1,509
Leigh Carter	2,766
Thomas A. Commes	5,509
William F. Conway	1,000
Wayne R. Embry	1,509
Robert J. Farling	36,879 (2)
George H. Kaull	5,551
Richard A. Miller	12,536
Frank E. Mosier	2,230
Sister Mary Marthe Reinhard, SND	1,506 (3)
Robert C. Savage	1,509
William J. Williams	2,293
Murray R. Edelman	14,580 (2)
Donald C. Shelton	5,893
Fred J. Lange, Jr.	5,606
Al R. Temple	3,449
All directors and executive officers as a group	139,179 (2)

(1) Beneficially owned shares include any shares with respect to which voting or investment power is attributed to a director or executive officer because of joint or fiduciary ownership of the shares or relationship to the record owner, such as a spouse, even though the director or executive officer does not consider himself or herself the beneficial owner. On February 28, 1995, all directors and executive officers of Centerior Energy and the Service Company as a group were considered to own beneficially 0.1% of Centerior's common stock and none of the preferred stock of Cleveland Electric and Toledo Edison except for one officer who owns 400 shares of Toledo Edison $2.81 Preferred Stock. Certain individuals disclaim beneficial ownership of some of those shares.

(2) Includes the following numbers of shares which are not owned but could have been purchased within 60 days after February 28, 1995 upon exercise of options to purchase shares of Centerior common stock: Mr. Farling - 3,330; Mr. Edelman - 5,550; and all directors and executive officers as a group - 11,655. None of those options have been exercised as of March 17, 1995.

(3) Owned by the Sisters of Notre Dame.

CLEVELAND ELECTRIC

Individual directors of Cleveland Electric, the named executive officers and all directors and executive officers of Cleveland Electric as a group beneficially owned the following number of shares of Centerior common stock as of February 28, 1995:

Name of Beneficial Owner	Number of Common Shares Owned (1)
Robert J. Farling	36,879 (2)
Murray R. Edelman	14,580 (2)
Donald C. Shelton	5,893
Fred J. Lange, Jr.	5,606
Al R. Temple	3,449
All directors and executive officers as a group	90,749 (2)

(1) Beneficially owned shares include any shares with respect to which voting or investment power is attributed to a director or executive officer because of joint or fiduciary ownership of the shares or relationship to the record owner, such as a spouse, even though the director or executive officer does not consider himself or herself the beneficial owner. On February 28, 1995, all directors and executive officers of Cleveland Electric as a group were considered to own beneficially 0.06% of Centerior's common stock and none of Cleveland Electric's serial preferred stock. Certain individuals disclaim beneficial ownership of some of those shares.

(2) Includes the following numbers of shares which are not owned but could have been purchased within 60 days after February 28, 1995 upon exercise of options to purchase shares of Centerior common stock: Mr. Farling - 3,330; Mr. Edelman - 5,550; and all directors and executive officers as a group - 9,990. None of those options have been exercised as of March 17, 1995.

TOLEDO EDISON

Individual directors of Toledo Edison, the named executive officers and all directors and executive officers of Toledo Edison as a group beneficially owned the following number of shares of Centerior common stock as of February 28, 1995:

Name of Beneficial Owner	Number of Common Shares Owned (1)
Robert J. Farling	36,879 (2)
Murray R. Edelman	14,580 (2)
Donald C. Shelton	5,893
Fred J. Lange, Jr.	5,606
Al R. Temple	3,449
All directors and executive officers as a group	80,398 (2)

(1) Beneficially owned shares include any shares with respect to which voting or investment power is attributed to a director or executive officer because of joint or fiduciary ownership of the shares or relationship to the record owner, such as a spouse, even though the director or executive officer does not consider himself or herself the beneficial owner. On February 28, 1995, all directors and executive officers of Toledo Edison as a group were considered to own beneficially 0.05% of Centerior's common stock and none of Toledo Edison's cumulative preferred stock except for one officer who owns 400 shares of $2.81 Preferred Stock. Certain individuals disclaim beneficial ownership of some of those shares.

(2) Includes the following numbers of shares which are not owned but could have been purchased within 60 days after February 28, 1995 upon exercise of options to purchase shares of Centerior common stock: Mr. Farling - 3,330; Mr. Edelman - 5,550; and all other executive officers as a group - 9,990. None of those options have been exercised as of March 17, 1995.

Item 13. Certain Relationships and Related Transactions

CENTERIOR ENERGY, CLEVELAND ELECTRIC AND TOLEDO EDISON

None.

PART IV

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

(a) Documents Filed as a Part of the Report

1. Financial Statements:

   Financial Statements for Centerior Energy, Cleveland Electric and Toledo Edison are listed in the Index to Selected Financial Data; Management's Discussion and Analysis of Financial Condition and Results of Operations; and Financial Statements. See Page F-1.

2. Financial Statement Schedules:

   Financial Statement Schedules for Centerior Energy, Cleveland Electric and Toledo Edison are listed in the Index to Schedules. See Page S-1.

3. Combined Pro Forma Condensed Financial Statements (Unaudited):

Combined Pro Forma Condensed Financial Statements (unaudited) for Cleveland Electric and Toledo Edison related to their pending merger. See Pages P-1 to P-4.

4. Exhibits:

Exhibits for Centerior Energy, Cleveland Electric and Toledo Edison are listed in the Exhibit Index. See Page E-1.

(b) Reports on Form 8-K

During the quarter ended December 31, 1994, Centerior Energy, Cleveland Electric and Toledo Edison did not file any Current Reports on Form 8-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CENTERIOR ENERGY CORPORATION
Registrant

March 21, 1995

By J. T. PERCIO
J. T. Percio, Secretary

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

Signature	Title	Date
Principal Executive Officer: *ROBERT J. FARLING	Chairman of the Board, President and Chief Executive Officer	March 21, 1995
Principal Financial Officer: *GARY R. LEIDICH	Vice President and Chief Financial Officer	
Principal Accounting Officer: *E. LYLE PEPIN	Controller	
Directors:		
*RICHARD P. ANDERSON	Director	
*ALBERT C. BERSTICKER	Director	
*LEIGH CARTER	Director	
*THOMAS A. COMMES	Director	
*WILLIAM F. CONWAY	Director	
*WAYNE R. EMBRY	Director	
*ROBERT J. FARLING	Director	
*GEORGE H. KAULL	Director	
*RICHARD A. MILLER	Director	
*FRANK E. MOSIER	Director	
*SR. MARY MARTHE REINHARD, SND	Director	
*ROBERT C. SAVAGE	Director	
*WILLIAM J. WILLIAMS	Director	

*By J. T. PERCIO
J. T. Percio, Attorney-in-Fact

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
Registrant

March 21, 1995

By J. T. PERCIO
J. T. Percio, Secretary

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

Signature	Title	Date
Principal Executive Officer:		
*ROBERT J. FARLING	Chairman of the Board and Chief Executive Officer	
Principal Financial Officer:		
*GARY R. LEIDICH	Vice President and Chief Financial Officer	March 21, 1995
Principal Accounting Officer:		
*E. LYLE PEPIN	Controller	
Directors:		
*ROBERT J. FARLING	Director	
*MURRAY R. EDELMAN	Director	
*FRED J. LANGE, JR.	Director	

*By J. T. PERCIO
J. T. Percio, Attorney-in-Fact

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE TOLEDO EDISON COMPANY
Registrant

March 21, 1995 By J. T. PERCIO
J. T. Percio, Secretary

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

Signature	Title		Date
Principal Executive Officer:		)	
*ROBERT J. FARLING	Chairman of the Board and Chief Executive Officer	)	
Principal Financial Officer:		)	
*GARY R. LEIDICH	Vice President and Chief Financial Officer	)	
Principal Accounting Officer:		)	March 21, 1995
*E. LYLE PEPIN	Controller	)	
Directors:		)	
*ROBERT J. FARLING	Director	)	
*MURRAY R. EDELMAN	Director	)	
*FRED J. LANGE, JR.	Director	)	

*By J. T. PERCIO
J. T. Percio, Attorney-in-Fact

INDEX TO SELECTED FINANCIAL DATA; MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS; AND FINANCIAL STATEMENTS

Report of Independent Public Accountants

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

We have audited the accompanying consolidated balance sheet and consolidated statement of preferred stock of Centerior Energy Corporation (an Ohio corporation) and subsidiaries as of December 31, 1994 and 1993, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1994. These financial statements and the schedule referred to below are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Centerior Energy Corporation and subsidiaries as of December 31, 1994 and 1993, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1994, 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.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule of Centerior Energy Corporation and subsidiaries listed in the Index to Schedules is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Cleveland, Ohio
February 17, 1995

Management's Financial Analysis

Outlook

Strategic Plan

We made significant strides in achieving the objectives of our comprehensive strategic action plan announced in January 1994. The strategic plan was created to strengthen our financial and competitive position through the year 2001. Its objectives are to maximize share owner return, achieve profitable revenue growth, become an industry leader in customer satisfaction, build a winning employee team and attain increasingly competitive power supply costs. To achieve these objectives, we will continue to control expenditures and reduce our outstanding debt and preferred stock. In addition, we will increase revenues by finding new uses for existing assets and resources, implementing new marketing programs and restructuring rates when appropriate. We will also improve the operating performance of our generating plants and take other appropriate actions.

During 1994, we made progress toward most of our long-term objectives. We initiated a marketing plan designed to increase our retail revenues (exclusive of fuel cost recovery revenues and weather influences) by 2-3% annually through 2001. Our new customer service activities are intended to raise our customer satisfaction rating. Our employees achieved enough of their established objectives for the year to receive a $500 per eligible employee incentive compensation award. The work undertaken during refueling outages at the Davis-Besse Nuclear Power Station (Davis-Besse) and Perry Nuclear Power Plant Unit 1 (Perry Unit 1) as well as the outage work at our fossil-fueled plants should help us achieve our long-term objective of reducing variable power costs to a more competitive level. Another long-term objective to be achieved over the planning period is to provide share owners a total annual return greater than the Standard & Poor's Corporation (S&P) 500 Index. While there was a slight gain in the S&P 500 Index in 1994, electric utility stocks in general, and Centerior Energy Corporation (Centerior Energy) common stock in particular, declined sharply. The climb in interest rates and increased investor concern about the competitiveness of the electric utility industry caused the Dow Jones Utility Average to drop 21% in 1994. The total return on our common stock in 1994, including dividends, was -27%. Investors placed a lower valuation on our stock principally because of our high retail cost structure relative to certain neighboring utilities and municipal electric systems.

As discussed below, we are taking steps to improve our competitiveness. As these efforts unfold and if interest rates decline and investor concerns about the electric utility industry diminish, the total annual return for our common stock should improve. Further improvement in several key financial measures should lead to a higher investor valuation of Centerior Energy. Substantial progress in these areas was made in 1994. Strong cash flow continued in 1994 and fixed-income obligations were reduced by $136 million. Also, total operation and maintenance expenses declined $88 million, exclusive of one-time charges in 1993.

We are taking aggressive steps to increase revenues through our enhanced marketing plan and to control costs. The full impact of these efforts will take time. In the meantime, to increase share owner value, we must raise revenues by restructuring rates. Accordingly, we are preparing to file a request with The Public Utilities Commission of Ohio (PUCO) for our two utility subsidiaries, The Cleveland Electric Illuminating Company (Cleveland Electric) and The Toledo Edison Company (Toledo Edison) (collectively, the Operating Companies) to be effective in 1996. Meaningful cost control and marketing strategies will mitigate the need for additional rate increases and help us meet competition.

Competition

We are implementing strategies designed to create and enhance our competitive advantages and to overcome the competitive disadvantages that we face due to regulatory and tax constraints and our high retail cost structure.

Currently our most pressing competition comes from municipal electric systems in our service area. Our rates are generally higher than those of municipal systems due largely to their exemption from taxation, the lower cost financing available to them, the continued availability to them of lower cost power through short-term power purchases and their access to cheaper governmental power. We are seeking to address the tax disparity through the legislative process. In 1994, the Ohio Governor's Tax Commission recommended the replacement of the gross receipts and personal property taxes currently levied only on investor-owned utilities and collected through rates with a different tax collected from customers of all electric utilities, including municipal systems. Investor-owned utilities would reduce rates upon repeal of the existing taxes. We are now working to submit this proposal to the Ohio legislature.

We face the threat that municipalities in our service area could establish new systems and continue expanding existing systems. We are responding with aggressive marketing programs and by emphasizing the value of our service and the risks of a municipal system: substantial, long-term debt; no guarantee of low-cost wholesale electricity; the difficulty of forecasting costs; and the uncertainty of market share as a result of our aggressive competition. Generally, these municipalities have determined that developing a system is not feasible or have agreed with us not to pursue development of a system at

this time. Although some communities continue to be interested in municipalization, we believe that we offer the best value and most reliable source of electric service in our territory.

The largest municipal system in our service area, Cleveland Public Power (CPP), is constructing new transmission and distribution facilities extending into eastern portions of Cleveland. CPP also plans to expand to western portions of Cleveland. CPP's expansion reduced our annual net income by about $4 million in 1993 and an additional $3 million in 1994. We estimate our net income will continue to be reduced by an additional $4 million to $5 million each year in the 1995-1999 period because of CPP's expansion. Despite CPP's expansion efforts, we have been successful in retaining most of the large industrial and commercial customers in the expansion areas by providing economic incentives in exchange for sole-supplier contracts. We have similar contracts with customers in other parts of our service area. More than 80% of our industrial revenues under contract will not be up for renewal until 1997 or later. As these contracts expire, we expect to renegotiate them and retain the customers. In addition, an increasing number of CPP customers are converting back to our service.

The Energy Policy Act of 1992 will increase competition in the electric utility industry by allowing broader access to a utility's transmission system. It should not significantly increase the competitive threat to us since we have been required to wheel electricity to municipal systems in our service area since 1977 under operating licenses for our nuclear generating units. Further, the government could eventually require utilities to deliver power from other utilities or generation sources to their retail customers. To combat this threat, we are offering incentives such as energy-efficiency improvements and reductions in demand charges for increased electricity usage to our industrial and commercial customers in return for long-term commitments.

Rate Matters

Under the Rate Stabilization Program discussed in Note 7, we agreed to freeze base rates until 1996 and limit rate increases through 1998. In exchange, we are permitted to defer through 1995 and subsequently recover certain costs not currently recovered in rates and to accelerate the amortization of certain benefits. Amortization and recovery of the deferrals are expected to begin in 1996 with future rate recognition and will continue over the average life of the related assets, or between 17 and 30 years. The continued use of these regulatory accounting measures in 1995 will be dependent upon our continuing assessment and conclusion that there will be probable recovery of such deferrals in future rates. Our analysis leading to certain year-end 1993 financial actions and our strategic plan also included an evaluation of our regulatory accounting measures. See Regulatory Accounting below and Note 7. We decided that, once the deferral of expenses and acceleration of benefits under the Rate Stabilization Program are completed in 1995, we should no longer plan to use these measures to the extent we have in the past.

Regulatory Accounting

As described in Notes 1(a) and 7, the Operating Companies comply with the provisions of Statement of Financial Accounting Standards (SFAS) 71. We continually 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 Operating Companies' ability to establish rates to recover operating costs, return requirements and the amortization of regulatory assets and (2) a significant change in the manner in which rates are set by the PUCO from cost-based regulations to some other form of regulations. In the event we determine that the Operating Companies no longer meet the criteria for following SFAS 71, we would be required to record a before-tax charge to write off the regulatory assets shown in Note 7. In addition, the Operating Companies would be required to evaluate whether the changes in the competitive and regulatory environment which led to discontinuing the application of SFAS 71 would also result in an impairment of the net book value of their property, plant and equipment.

The write-off in 1993 of the phase-in deferred operating expenses and carrying charges (phase-in deferrals) discussed in Note 7 resulted from our conclusion that projected revenues for the 1994-1998 period would not provide for recovery of such deferrals as scheduled by the PUCO orders. This short time frame for recovery of the phase-in deferrals is a requirement under the accounting standard for phase-in plans of regulated enterprises, SFAS 92. The remaining recovery periods for all remaining regulatory assets are between 17 and 34 years. We believe the Operating Companies' rates will provide for recovery of these assets over the relevant periods and SFAS 71 continues to apply.

Nuclear Operations

We have interests in three nuclear generating units — Davis-Besse, Perry Unit 1 and Beaver Valley Power Station Unit 2 (Beaver Valley Unit 2) — and operate the first two. Davis-Besse and Beaver Valley Unit 2 have been operating extremely well, with each unit having a three-year availability average at year-end 1994 that exceeded the three-year industry average of 80% for similar reactors. However, the three-year availability av-

erage of Perry Unit 1 was below the three-year industry availability average for that reactor type.

In 1994, Davis-Besse had an availability factor of 88%. Further, Davis-Besse completed the shortest refueling and maintenance outage in its history in 1994, returning to service just 46 days after shutting down. We are in the process of upgrading Perry Unit 1 to the same level. For seven months in 1994, Perry Unit 1 was out of service for its fourth refueling and maintenance outage. Work was also performed in connection with the comprehensive course of action developed in 1993 to improve the operating performance of Perry Unit 1. Work in connection with that course of action is ongoing.

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(d).

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 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.

Hazardous Waste Disposal Sites

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended (Superfund) established programs addressing the cleanup of hazardous waste disposal sites, emergency preparedness and other issues. The Operating Companies have been named as "potentially responsible parties" (PRPs) for three sites listed on the Superfund National Priorities List (Superfund List) and are aware of their potential involvement in the cleanup of several other sites. Allegations that the Operating Companies disposed of hazardous waste at these sites, and the amounts involved, are often unsubstantiated and subject to dispute. Superfund provides that all PRPs for a particular site can be held liable on a joint and several basis. If the Operating Companies were held liable for 100% of the cleanup costs of all of the sites referred to above, the cost could be as high as $500 million. However, we believe that the actual cleanup costs will be substantially lower than $500 million, that the Operating Companies' share of any cleanup costs will be substantially less than 100% and that most of the other PRPs are financially able to contribute their share. The Operating Companies have accrued a liability totaling $13 million at December 31, 1994 based on estimates of the costs of cleanup and their proportionate responsibility for such costs. We believe that the ultimate outcome of these matters will not have a material adverse effect on our financial condition or results of operations.

Merger of the Operating Companies

We continue to seek the necessary regulatory approvals to complete the merger of the Operating Companies which we announced in 1994. The Operating Companies plan to seek preferred stock share owner approval in mid-1995. The merger is expected to be effective in 1995.

Inflation

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

Capital Resources and Liquidity

1992-1994 Cash Requirements

We need cash for normal corporate operations, the mandatory retirement of securities and constructing and modifying facilities. Construction is needed to meet anticipated demand for electric service, comply with government regulations and protect the environment. Over the three-year period 1992-1994, construction and mandatory retirement needs totaled approximately $1.3 billion. In addition, we exercised options to redeem and purchase approximately $900 million of our securities.

We raised $1.7 billion through security issues and term bank loans during the 1992-1994 period. The Operating Companies also utilized short-term borrowings to help meet cash needs. Although write-offs of our Perry Nuclear Power Plant Unit 2 (Perry Unit 2) investment and phase-in deferrals in 1993 negatively affected earnings, they did not adversely affect cash flow. See Notes 4(b) and 7.

1995 and Beyond Cash Requirements

Estimated cash requirements for 1995-1999 for Cleveland Electric and Toledo Edison, respectively, are $802 million and $288 million for construction and $832 million and $378 million for the mandatory redemption of debt and preferred stock. Cleveland Electric expects to finance externally about two-thirds of its 1995 cash requirements of approximately $451 million and about one-third of its

1996 cash requirements of approximately $320 million. Toledo Edison expects to meet nearly all of its 1995 and 1996 cash requirements of approximately $145 million and $154 million, respectively, through internal cash generation and current cash resources. The Operating Companies expect to meet nearly all of their 1997-1999 requirements through internal cash generation and current cash resources. If economical, additional securities may be redeemed under optional redemption provisions. We expect that our continued strong cash flow will reduce borrowing requirements and outstanding debt and preferred stock during this period.

Cash expenditures to comply with the Clean Air Act Amendments of 1990 (Clean Air Act) are estimated to be approximately $87 million over the 1995-1999 period. See Note 4(a).

Liquidity

Additional first mortgage bonds may be issued by the Operating Companies under their respective mortgages on the basis of property additions, cash or refundable first mortgage bonds. If the applicable interest coverage test is met, each Operating Company may issue first mortgage bonds on the basis of property additions and, under certain circumstances, refundable bonds. At December 31, 1994, Cleveland Electric and Toledo Edison would have been permitted to issue approximately $487 million and $525 million of additional first mortgage bonds, respectively.

The Operating Companies also are able to raise funds through the sale of subordinated debt and preferred and preference stock. Under its articles of incorporation, Toledo Edison cannot issue preferred stock unless certain earnings coverage requirements are met. At December 31, 1994, Toledo Edison would have been permitted to issue approximately $28 million of additional preferred stock at an assumed dividend rate of 12%. There are no restrictions on Cleveland Electric's ability to issue preferred or preference stock or Toledo Edison's ability to issue preference stock.

Centerior Energy may raise funds through the sale of common stock under various employee and share owner plans. In 1995, the Operating Companies plan to raise funds through the sale of first mortgage bonds and the collateralization of accounts receivable.

We have a $205 million revolving credit facility which runs through mid-1996. See Note 12. We had $186 million of cash and temporary cash investments at the end of 1994. The Operating Companies are unable to issue commercial paper because of their below investment grade commercial paper ratings.

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

	S&P	Moody's Investors Service, Inc.
First mortgage bonds	BB	Ba2
Unsecured notes for Cleveland Electric	B+	Ba3
Unsecured notes for Toledo Edison	B+	B1
Preferred stock	B	b2

In 1994, the common stock dividend was lowered which reduced our cash outflow by over $110 million annually. We are using the cash to redeem debt and preferred stock more quickly than would otherwise be the case. This has helped improve our capitalization structure and fixed charge coverage ratios, both of which are key measures considered by securities rating agencies in determining credit ratings. Improved credit ratings and less outstanding debt and preferred stock, in turn, will lower our interest costs and preferred dividends.

Results of Operations

1994 vs. 1993

Factors contributing to the 2.1% decrease in 1994 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$ 10
Wholesale Revenues	(47)
Fuel Cost Recovery Revenues	(22)
Miscellaneous Revenues	6
Total	$(53)

Centerior Energy 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 primarily from milder weather conditions in 1994 and 39% lower wholesale sales. Weather reduced base rate revenues approximately $15 million from the 1993 amount. Although total sales decreased by 1.9%, industrial sales increased 3.3% 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 our service area, particularly in Northwestern Ohio. Residential and commercial sales increased 0.1% and 2.4%, respectively. Other sales decreased by 28% because of the lower sales to wholesale customers attributable to expiration of a wholesale power agreement, softer wholesale market conditions and limited power availability for bulk power transactions at certain times because of generating plant outages. Lower 1994 fuel cost recovery revenues resulted from favorable changes in the fuel cost factors. The weighted averages

of these factors dropped by 5% and 6% for Cleveland Electric and Toledo Edison, respectively.

For 1994, operating revenues were 31% residential, 30% commercial, 31% industrial and 8% other and kilowatt-hour sales were 24% residential, 25% commercial, 41% industrial and 10% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.10 and $.06, respectively.

Operating expenses were 15% lower in 1994. Operation and maintenance expenses for 1993 included $218 million of net benefit expenses related to an early retirement program, called the Voluntary Transition Program (VTP), and other charges totaling $54 million. Two other significant reasons for lower operation and maintenance expenses in 1994 were a smaller work force and ongoing cost reduction measures. More nuclear generation and less coal-fired generation accounted for a large part of the lower fuel and purchased power expenses in 1994. Depreciation and amortization expenses increased primarily because of higher nuclear plant decommissioning expenses as discussed in Note 1(d). Deferred operating expenses were greater primarily because of the write-off of $172 million of phase-in deferred operating expenses in 1993 as discussed in Note 7. The 1993 deferrals also included $84 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), $583 million of our Perry Unit 2 investment was written off in 1993. Also, as discussed in Note 7, phase-in deferred carrying charges of $705 million were written off in 1993. The change in the federal income tax credit amounts for nonoperating income was attributable to these write-offs.

1993 vs. 1992

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

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

The revenue increase resulted primarily from the different weather conditions and the changes in the composition of the sales mix among customer categories. Weather accounted for approximately $47 million of higher 1993 base rate revenues. Hot summer weather in 1993 boosted residential, commercial and wholesale kilowatt-hour sales. In contrast, the 1992 summer was the coolest in 56 years for Northern Ohio. Residential and commercial sales also increased as a result of colder late-winter temperatures in 1993 which increased electric heating-related demand. As a result, total sales increased 3.1% in 1993. Residential and commercial sales increased 4.6% and 3.1%, respectively. Industrial sales increased 1.2%. Increased sales to large automotive manufacturers, petroleum refiners and the broad-based, smaller industrial customer group were partially offset by lower sales to large steel industry customers. Other sales increased 5.9% because of increased sales to wholesale customers. Base rates and miscellaneous revenues decreased in 1993 primarily from lower revenues under contracts having reduced rates with certain large customers and a declining rate structure tied to usage. The contracts have been negotiated to meet competition and encourage economic growth. The decrease in 1993 fuel cost recovery revenues resulted from changes in the fuel cost factors. The weighted average of these factors increased slightly for Toledo Edison but decreased 5% for Cleveland Electric.

For 1993, operating revenues were 31% residential, 29% commercial, 30% industrial and 10% other and kilowatt-hour sales were 23% residential, 24% commercial, 39% industrial and 14% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.10 and $.06, respectively. The changes from 1992 were not significant.

Operating expenses increased 14% in 1993. The increase in total operation and maintenance expenses resulted from the $218 million of net benefit expenses related to the VTP, other charges totaling $54 million and an increase in other operation and maintenance expenses. The increase in other operation and maintenance expenses resulted from higher environmental expenses, power restoration and repair expenses following a July 1993 storm in the Cleveland area, and an increase in other postretirement benefit expenses. See Note 9 for information on retirement benefits. Deferred operating expenses decreased because of the write-off of the phase-in deferred operating expenses in 1993. Federal income taxes decreased as a result of lower pretax operating income.

As mentioned above, $583 million of our Perry Unit 2 investment was written off in 1993. Credits for carrying charges recorded in nonoperating income decreased because of the write-off of the phase-in deferred carrying charges in 1993. The federal income tax credit for nonoperating income in 1993 resulted from the write-offs.

Income Statement

Centerior Energy Corporation and Subsidiaries

	1994	1993	1992
	For the years ended December 31, (millions of dollars, except per share amounts)		
Operating Revenues	$2,421	$2,474	$2,438
Operating Expenses			
Fuel and purchased power	442	474	473
Other operation and maintenance	595	652	623
Generation facilities rental expense, net	160	159	161
Early retirement program expenses and other	—	272	—
Total operation and maintenance	1,197	1,557	1,257
Depreciation and amortization	278	258	256
Taxes, other than federal income taxes	309	312	318
Deferred operating expenses, net	(55)	23	(52)
Federal income taxes	114	11	122
	1,843	2,161	1,901
Operating Income	578	313	537
Nonoperating Income (Loss)			
Allowance for equity funds used during construction	5	5	2
Other income and deductions, net	8	(6)	9
Write-off of Perry Unit 2	—	(583)	—
Deferred carrying charges, net	40	(649)	100
Federal income taxes — credit (expense)	(6)	398	(7)
	47	(835)	104
Income (Loss) Before Interest Charges and Preferred Dividends	625	(522)	641
Interest Charges and Preferred Dividends			
Debt interest	361	359	365
Allowance for borrowed funds used during construction	(6)	(5)	(1)
Preferred dividend requirements of subsidiaries	66	67	65
	421	421	429
Net Income (Loss)	$ 204	$ (943)	$ 212
Average Number of Common Shares Outstanding (millions)	147.8	144.9	141.7
Earnings (Loss) Per Common Share	$ 1.38	$(6.51)	$ 1.50
Dividends Declared Per Common Share	$ .80	$ 1.60	$ 1.60

Retained Earnings

	1994	1993	1992
	For the years ended December 31, (millions of dollars)		
Retained Earnings (Deficit) at Beginning of Year	$(523)	$ 652	$ 669
Additions			
Net income (loss)	204	(943)	212
Deductions			
Common stock dividends	(118)	(231)	(226)
Other, primarily preferred stock redemption expenses of subsidiaries	(1)	(1)	(3)
Net Increase (Decrease)	85	(1,175)	(17)
Retained Earnings (Deficit) at End of Year	$(438)	$ (523)	$ 652

The accompanying notes are an integral part of these statements.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Balance Sheet

	December 31, 1994	December 31, 1993
	(millions of dollars)	
ASSETS		
Property, Plant and Equipment		
Utility plant in service	$ 9,770	$ 9,571
Less: accumulated depreciation and amortization	2,906	2,677
	6,864	6,894
Construction work in progress	129	181
	6,993	7,075
Nuclear fuel, net of amortization	293	344
Other property, less accumulated depreciation	50	41
	7,336	7,460
Current Assets		
Cash and temporary cash investments	186	225
Amounts due from customers and others, net	211	221
Unbilled revenues	93	124
Materials and supplies, at average cost	139	136
Fossil fuel inventory, at average cost	29	32
Taxes applicable to succeeding years	252	250
Other	16	5
	926	993
Deferred Charges and Other Assets		
Amounts due from customers for future federal income taxes	1,046	968
Unamortized loss from Beaver Valley Unit 2 sale	101	105
Unamortized loss on reacquired debt	86	92
Carrying charges and operating expenses	957	862
Nuclear plant decommissioning trusts	82	56
Other	157	174
	2,429	2,257
Total Assets	$10,691	$10,710

The accompanying notes are an integral part of this statement.

	December 31,	
	1994	1993
	(millions of dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shares, without par value (stated value of $357 million and $345 million for 1994 and 1993, respectively): 180 million authorized; 148 million (excluding 2.7 million shares in Treasury) and 147 million (excluding 2.7 million shares in Treasury) outstanding in 1994 and 1993, respectively	$ 2,320	$ 2,308
Retained earnings (deficit)	(438)	(523)
Common stock equity	1,882	1,785
Preferred stock		
With mandatory redemption provisions	253	313
Without mandatory redemption provisions	451	451
Long-term debt	3,697	4,019
	6,283	6,568
Current Liabilities		
Current portion of long-term debt and preferred stock	373	127
Current portion of nuclear fuel lease obligations	83	111
Accounts payable	144	188
Accrued taxes	384	378
Accrued interest	90	87
Other	75	75
	1,149	966
Deferred Credits and Other Liabilities		
Unamortized investment tax credits	279	329
Accumulated deferred federal income taxes	1,778	1,579
Unamortized gain from Bruce Mansfield Plant sale	525	551
Accumulated deferred rents for Bruce Mansfield Plant and Beaver Valley Unit 2	139	128
Nuclear fuel lease obligations	219	254
Retirement benefits	176	160
Other	143	175
	3,259	3,176
Total Capitalization and Liabilities	$10,691	$10,710

Cash Flows

Centerior Energy Corporation and Subsidiaries

	For the years ended December 31,		
	1994	1993	1992
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income (Loss)	$ 204	$ (943)	$ 212
Adjustments to Reconcile Net Income (Loss) to Cash from Operating Activities:			
Depreciation and amortization	278	258	256
Deferred federal income taxes	95	(452)	95
Investment tax credits, net	—	—	(14)
Unbilled revenues	31	(10)	(6)
Deferred fuel	(17)	5	1
Deferred carrying charges, net	(40)	649	(100)
Leased nuclear fuel amortization	98	86	126
Deferred operating expenses, net	(55)	23	(52)
Allowance for equity funds used during construction	(5)	(5)	(2)
Noncash early retirement program expenses, net	—	208	—
Write-off of Perry Unit 2	—	583	—
Changes in amounts due from customers and others, net	10	1	7
Changes in inventories	—	26	(10)
Changes in accounts payable	(44)	45	(5)
Changes in working capital affecting operations	—	25	8
Other noncash items	14	18	3
Total Adjustments	365	1,460	307
Net Cash from Operating Activities	569	517	519
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	—	(50)	50
First mortgage bond issues	77	300	600
Secured medium-term note issues	—	128	138
Term bank loans and other long-term debt issues	—	40	135
Preferred stock issues	—	100	74
Common stock issues	12	71	53
Reacquired common stock	—	1	(3)
Maturities, redemptions and sinking funds	(214)	(434)	(1,013)
Nuclear fuel lease obligations	(110)	(106)	(117)
Common stock dividends paid	(118)	(231)	(226)
Premiums, discounts and expenses	(1)	(13)	(14)
Net Cash from Financing Activities	(354)	(194)	(323)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(205)	(209)	(200)
Interest capitalized as allowance for borrowed funds used during construction	(6)	(5)	(1)
Sale and leaseback restructuring fees	—	—	(43)
Contributions to nuclear plant decommissioning trusts	(26)	(9)	(8)
Other cash received (applied)	(17)	32	(28)
Net Cash from Investing Activities	(254)	(191)	(280)
Net Change in Cash and Temporary Cash Investments	(39)	132	(84)
Cash and Temporary Cash Investments at Beginning of Year	225	93	177
Cash and Temporary Cash Investments at End of Year	$ 186	$ 225	$ 93

(1) Interest paid (net of amounts capitalized) was $300 million, $295 million and $299 million in 1994, 1993 and 1992, respectively. Income taxes paid were $6 million, $50 million and $32 million in 1994, 1993 and 1992, respectively.

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

The accompanying notes are an integral part of this statement.

Statement of Preferred Stock

	1994 Shares Outstanding	Current Call Price Per Share	December 31, 1994	December 31, 1993
			(millions of dollars)	
CLEVELAND ELECTRIC				
Without par value, 4,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$ 7.35 Series C	140,000	$ 101.00	$ 14	$ 15
88.00 Series E	18,000	1,019.13	18	21
Adjustable Series M	100,000	100.00	10	20
9.125 Series N	410,766	102.03	41	59
91.50 Series Q	75,000	—	75	75
88.00 Series R	50,000	—	50	50
90.00 Series S	75,000	—	74	74
			282	314
Less: Current maturities			36	29
			246	285
Not subject to mandatory redemption:				
$ 7.40 Series A	500,000	101.00	50	50
7.56 Series B	450,000	102.26	45	45
Adjustable Series L	500,000	100.00	49	49
42.40 Series T	200,000	—	97	97
			241	241
TOLEDO EDISON				
$100 par value, 3,000,000 preferred shares authorized and $25 par value, 12,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$100 par $9.375	83,500	101.98	8	10
25 par 2.81	400,000	25.62	10	30
			18	40
Less: Current maturities			11	12
			7	28
Not subject to mandatory redemption:				
$100 par $ 4.25	160,000	104.625	16	16
4.56	50,000	101.00	5	5
4.25	100,000	102.00	10	10
8.32	100,000	102.46	10	10
7.76	150,000	102.437	15	15
7.80	150,000	101.65	15	15
10.00	190,000	101.00	19	19
25 par 2.21	1,000,000	25.25	25	25
2.365	1,400,000	27.75	35	35
Series A Adjustable	1,200,000	25.75	30	30
Series B Adjustable	1,200,000	25.75	30	30
			210	210
CENTERIOR ENERGY				
Without par value, 5,000,000 preferred shares authorized, none outstanding			—	—
Total Preferred Stock, with Mandatory Redemption Provisions			$253	$313
Total Preferred Stock, without Mandatory Redemption Provisions			$451	$451

The accompanying notes are an integral part of this statement.

Notes to the Financial Statements

(1) Summary of Significant Accounting Policies

(a) General

Centerior Energy is a holding company with two electric utility subsidiaries, Cleveland Electric and Toledo Edison. The consolidated financial statements also include the accounts of Centerior Energy's wholly owned subsidiary, Centerior Service Company (Service Company), and Centerior Energy's four other wholly owned subsidiaries, which in the aggregate are not material. During 1994, Cleveland Electric transferred its common stock investments in three wholly owned subsidiaries to Centerior Energy via property dividends and Centerior Energy formed the fourth wholly owned subsidiary. The Service Company provides management, financial, administrative, engineering, legal and other services at cost to Centerior Energy, the Operating Companies and the other subsidiaries. The Operating Companies operate as separate companies, each serving the customers in its service area. The preferred stock, first mortgage bonds and other debt obligations of the Operating Companies are outstanding securities of the issuing utility. All significant intercompany items have been eliminated in consolidation.

Centerior Energy and the Operating Companies follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission and adopted by the 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 Service Company follows the Uniform System of Accounts for Mutual Service Companies prescribed by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935.

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

(b) Revenues

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

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

(c) Fuel Expense

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

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

Owners of nuclear generating plants are assessed by the federal government for the cost of decontamination and decommissioning of nuclear enrichment facilities operated by the United States Department of Energy. The assessments are based upon the amount of enrichment services used in prior years and cannot be imposed for more than 15 years (to 2007). The Operating Companies have accrued the liability for their share of the total assessments. These costs have been recorded in a deferred charge account since the PUCO is allowing the Operating Companies to recover the assessments through their fuel cost factors.

(d) Depreciation and Amortization

The cost of property, plant and equipment is depreciated over their estimated useful lives on a straight-line basis. The annual straight-line depreciation provision for nonnuclear property expressed as a percent of average depreciable utility plant in service was 3.4% in 1994, 3.5% in 1993 and 3.4% in 1992. The annual straight-line depreciation rate for nuclear property is 2.5%.

The Operating Companies accrue the estimated costs of decommissioning their 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 allowing net earnings to 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 Operating Companies increased their annual decommissioning expense accruals to $24 million from the $8 million level in 1992. The accruals are reflected in current rates. The increased accruals were derived from recently 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	$346(1)	$ 862
Perry Unit 1	2026	256(1)	908
Beaver Valley Unit 2	2027	114(2)	423
Total		$716	$2,193

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

The updated estimates reflect substantial increases from the prior PUCO-recognized aggregate estimates of $257 million in 1987 and 1986 dollars.

The classification, Accumulated Depreciation and Amortization, in the Balance Sheet at December 31, 1994 includes $98 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 SEC has questioned certain of the current accounting practices of the electric utility industry, including those of the Operating Companies, 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 is reviewing the accounting for removal costs, including decommissioning. If such 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.

(e) Property, Plant and Equipment

Property, plant and equipment are stated at original cost less amounts ordered by the PUCO to be written off. Construction costs include related payroll taxes, 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 rates averaged 9.8% in 1994, 9.9% in 1993 and 10.8% in 1992.

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.

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

The sale and leaseback transactions discussed in Note 2 resulted in a net gain for the sale of the Bruce Mansfield Generating Plant (Mansfield Plant) and a net loss for the sale of Beaver Valley Unit 2. The net gain and net loss were deferred and are being amortized over the terms of leases. See Note 7. These amortizations and the lease expense amounts are reported in the Income Statement as Generation Facilities Rental Expense, Net.

(g) 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. 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.

(h) Federal Income Taxes

We use 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, we must record a liability for our tax obligation. The PUCO permits recovery of such taxes from customers when they become payable. Therefore, the net amount due from customers through rates has been recorded as a deferred charge and will be recovered over the lives of the related assets. See Note 7.

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

(2) Utility Plant Sale and Leaseback Transactions

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

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

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

Future minimum lease payments under the operating leases at December 31, 1994 are summarized as follows:

Year	Amount (millions of dollars)
1995	$ 166
1996	188
1997	165
1998	165
1999	178
Later Years	3,239
Total Future Minimum Lease Payments	$4,101

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1994, 1993 and 1992 as annual rental expense for the Mansfield Plant leases was $115 million. The amounts recorded in 1994, 1993 and 1992 as annual rental expense for the Beaver Valley Unit 2 lease were $64 million, $63 million and $66 million, respectively. Amounts charged to expense in excess of the lease payments are classified as Accumulated Deferred Rents in the Balance Sheet.

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

(3) Property Owned with Other Utilities and Investors

The Operating Companies own, as tenants in common with other utilities and those investors who are owner-participants in various sale and leaseback transactions (Lessors), certain generating units as listed below. Each owner owns an undivided share in the entire unit. Each owner has the right to a percentage of the generating capability of each unit equal to its ownership share. Each utility owner is obligated to pay for only its respective share of the construction costs and operating expenses. Each Lessor has leased its capacity rights to a utility which is obligated to pay for such Lessor's share of the construction costs and operating expenses. The Operating Companies' share of the operating expenses of these generating units is included in the Income Statement. The Balance Sheet classification of Property, Plant and Equipment at December 31, 1994 includes the following facilities owned by the Operating Companies as tenants in common with other utilities and Lessors:

Generating Unit	In-Service Date	Ownership Share	Ownership Megawatts	Power Source	Plant in Service	Construction Work in Progress	Accumulated Depreciation
					(millions of dollars)		
Seneca Pumped Storage	1970	80.00%	351	Hydro	$ 66	$—	$ 22
Eastlake Unit 5	1972	68.80	411	Coal	156	1	—
Perry Unit 1	1987	51.02	609	Nuclear	2,817	9	511
Beaver Valley Unit 2 and Common Facilities (Note 2)	1987	26.12	214	Nuclear	1,480	4	292
Total					$4,519	$14	$825

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

(4) Construction and Contingencies

(a) Construction Program

The estimated cost of our construction program for the 1995-1999 period is $1.154 billion, including AFUDC of $64 million and excluding nuclear fuel.

The 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 1994 in connection with Clean Air Act compliance amounted to $35 million. The plan will require additional capital expenditures over the 1995-2004 period of approximately $157 million for nitrogen oxide control equipment and plant modifications. In addition, higher fuel and other operation and maintenance expenses will be incurred. The anticipated rate increase associated with the capital expenditures and higher expenses would be about 1-2% in the late 1990s. Cleveland Electric may need to install sulfur emission control technology at one of its generating plants after 2005 which could require additional expenditures at that time.

(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 $583 million ($425 million after taxes) for our 64.76% ownership share of the unit. See Note 14.

(c) Hazardous Waste Disposal Sites

The Operating Companies are aware of their potential involvement in the cleanup of three sites listed on the Superfund List and several other waste sites not on such list. The Operating Companies have accrued a liability totaling $13 million at December 31, 1994 based on estimates of the costs of cleanup and their proportionate responsibility for such costs. We believe that the ultimate outcome of these matters will not have a material adverse effect on our financial condition or results of operations. See Management's Financial Analysis — Outlook-Hazardous Waste Disposal Sites.

(5) Nuclear Operations and Contingencies

(a) Operating Nuclear Units

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

(b) Nuclear Insurance

The Price-Anderson Act limits the 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), our maximum potential assessment under that plan would be $155 million (plus any inflation adjustment) per incident. The assessment is limited to $20 million per year for each nuclear incident. These assessment limits assume the other CAPCO companies contribute their proportionate share of any assessment.

The 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, 1995. Damage to property could exceed the insurance coverage by a substantial amount. If it does, our share of such excess amount could have a material adverse effect on our financial condition and results of operations. Under these policies, we can be assessed a maximum of $22 million during a policy year if the reserves available to the insurer are inadequate to pay claims arising out of an accident at any nuclear facility covered by the insurer.

We also have extra expense insurance coverage. It includes the incremental cost of any replacement power purchased (over the costs which would have been incurred had the units been operating) and other incidental expenses after the occurrence of certain types of accidents at our nuclear units. The amounts of the coverage are 100% of the estimated extra expense per week during the 52-week period starting 21 weeks after an accident and 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 Operating Companies through leases with a special-purpose corporation. At December 31, 1994, $307 million of nuclear fuel was financed ($157 million from intermediate-term notes and $150 million from bank credit arrangements). The intermediate-term notes mature in 1996 and 1997. The Operating Companies severally lease their respective portions of the nuclear fuel and are obligated to pay for the fuel as it is consumed in a reactor. The lease rates are based on various intermediate-term note rates, bank rates and commercial paper rates.

The amounts financed include nuclear fuel in the Davis-Besse, Perry Unit 1 and Beaver Valley Unit 2 reactors with remaining lease payments of $128 million, $91 million and $24 million, respectively, at December 31, 1994. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $11 million in 1994, $14 million in 1993 and $15 million in 1992. The estimated future lease amortization payments based on projected consumption are $99 million in 1995, $91 million in 1996, $80 million in 1997, $73 million in 1998 and $62 million in 1999.

(7) Regulatory Matters

The Operating Companies are subject to the provisions of SFAS 71. Regulatory assets represent probable future revenues to the Operating Companies associated with certain incurred costs, which they will recover from customers through the ratemaking process. Regulatory assets in the Balance Sheet are as follows:

	December 31,	
	1994	1993
	(millions of dollars)	
Amounts due from customers for future federal income taxes	$1,046	$ 968
Unamortized loss from Beaver Valley Unit 2 sale	101	105
Unamortized loss on reacquired debt	86	92
Pre-phase-in deferrals*	570	587
Rate Stabilization Program deferrals	387	275
Total	$2,190	$2,027

* 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, 1994, 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 17 to 34 years. The Operating Companies continually assess the effects of competition and the changing industry and regulatory environment on operations and their ability to recover the regulatory assets. In the event that the Operating Companies determine that future revenues would not be provided for recovery of any regulatory asset, such asset would be required to be written off. See Management's Financial Analysis — Outlook-Regulatory Accounting.

The Operating Companies will file a request with the PUCO to restructure rates to increase revenues to be effective in 1996 which will include provision for recovery of the Rate Stabilization Program deferrals. We believe that rates will be set at a level consistent with cost-based regulations and will provide revenues to recover the then-current operating costs, return requirements and amortization of all regulatory assets listed above.

The Rate Stabilization Program that the PUCO approved in October 1992 was designed to encourage economic

growth in our service area by freezing base rates until 1996 and limiting subsequent rate increases to specified annual amounts not to exceed $216 million for Cleveland Electric and $89 million for Toledo Edison over the 1996-1998 period.

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

The regulatory accounting measures we are eligible to record through December 31, 1995 include the deferral of post-in-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988 and the deferral of Toledo Edison operating expenses equivalent to an accumulated excess rent reserve for Beaver Valley Unit 2 (which resulted from the April 1992 refinancing of SLOBs as discussed in Note 2). The cost deferrals recorded in 1994, 1993 and 1992 pursuant to these provisions were $106 million, $95 million and $84 million, respectively. The regulatory accounting measures also provide for the accelerated amortization of certain unrestricted excess deferred tax and unrestricted investment tax credit balances and interim spent fuel storage accrual balances for Davis-Besse. The total amount of such regulatory benefits recognized pursuant to these provisions was $46 million in both 1994 and 1993 and $12 million in 1992.

The Rate Stabilization Program also authorized the Operating Companies to defer and subsequently recover the incremental expenses associated with the adoption of the accounting standard for postretirement benefits other than pensions (SFAS 106). In 1994 and 1993, we deferred $6 million and $96 million, respectively, pursuant to this provision. Amortization and recovery of these deferrals are expected to commence in 1996 and to be completed by no later than 2012. See Note 9(b).

In 1993, upon completing a comprehensive study which led to our current strategic plan, we concluded that projected revenues would not provide for recovery of deferrals recorded pursuant to phase-in plans approved by the PUCO in 1989. Such deferrals were scheduled to be recovered over the 1994 through 1998 period. The total phase-in deferred operating expenses and carrying charges written off at December 31, 1993 were $172 million and $705 million, respectively (totaling $598 million after taxes). See Note 14. Additionally, based on our assessment of business conditions, we concluded that, once the deferral of expenses and acceleration of benefits under our Rate Stabilization Program are completed in 1995, we should no longer plan to use regulatory accounting measures to the extent we have in the past.

(8) Federal Income Tax

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

	1994	1993	1992
	(millions of dollars)		
Operating Expenses:			
Current	$ 70	$ 99	$ 71
Deferred	44	(88)	51
Total Charged to Operating Expenses	114	11	122
Nonoperating Income:			
Current	(45)	(34)	(38)
Deferred	51	(364)	45
Total Expense (Credit) to Nonoperating Income	6	(398)	7
Total Federal Income Tax Expense (Credit)	$120	$(387)	$129

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 the income before taxes and preferred dividend requirements of subsidiaries by the statutory rate (35% in 1994 and 1993 and 34% in 1992), is reconciled to the amount of federal income tax recorded on the books as follows:

	1994	1993	1992
	(millions of dollars)		
Book Income (Loss) Before Federal Income Tax	$390	$(1,263)	$406
Tax (Credit) on Book Income (Loss) at Statutory Rate	$137	$ (442)	$138
Increase (Decrease) in Tax:			
Write-off of Perry Unit 2	—	46	—
Write-off of phase-in deferrals	—	28	—
Depreciation	3	(6)	(9)
Rate Stabilization Program	(27)	(30)	(7)
Other items	7	17	7
Total Federal Income Tax Expense (Credit)	$120	$ (387)	$129

For tax reporting purposes, the Perry Unit 2 abandonment was recognized in 1994 and resulted in a $307 million loss with a corresponding $107 million reduction in federal income tax liability. Because of the alternative minimum tax (AMT), $62 million of the $107 million was realized in 1994. The remaining $45 million will not be realized until 1999. Additionally, a repayment of approximately $32 million of previously allowed investment tax credits was recognized in 1994.

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

Under SFAS 109, temporary differences and carryforwards resulted in deferred tax assets of $596 million and deferred tax liabilities of $2.374 billion at December 31, 1994 and deferred tax assets of $619 million and deferred tax liabilities of $2.198 billion at December 31, 1993. These are summarized as follows:

	December 31, 1994	December 31, 1993
	(millions of dollars)	
Property, plant and equipment	$2,035	$1,845
Deferred carrying charges and operating expenses	215	206
Net operating loss carryforwards	(144)	(108)
Investment tax credits	(156)	(183)
Sale and leaseback transactions	(128)	(127)
Other	(44)	(54)
Net deferred tax liability	$1,778	$1,579

For tax purposes, net operating loss (NOL) carryforwards of approximately $412 million are available to reduce future taxable income and will expire in 2003 through 2009. The 35% tax effect of the NOLs is $144 million. Additionally, AMT credits of $168 million that may be carried forward indefinitely are available to reduce future regular tax.

(9) Retirement Benefits

(a) Retirement Income Plan

We sponsor a noncontributing 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. Our funding policy is to comply with the Employee Retirement Income Security Act of 1974 guidelines.

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

Pension and VTP costs (credits) for 1992 through 1994 were comprised of the following components:

	1994	1993	1992
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 13	$ 15	$ 15
Interest cost on projected benefit obligation	26	37	38
Actual return on plan assets	(2)	(65)	(24)
Net amortization and deferral	(34)	4	(45)
Net pension costs (credits)	3	(9)	(16)
VTP cost	—	205	—
Settlement gain	—	(81)	—
Net costs (credits)	$ 3	$115	$(16)

The following table presents a reconciliation of the funded status of the plan.

	December 31, 1994	December 31, 1993
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$278	$333
Nonvested benefits	2	37
Accumulated benefit obligation	280	370
Effect of future compensation levels	37	53
Total projected benefit obligation	317	423
Plan assets at fair market value	362	386
Funded status	45	(37)
Unrecognized net loss (gain) from variance between assumptions and experience	(79)	11
Unrecognized prior service cost	10	10
Transition asset at January 1, 1987 being amortized over 19 years	(39)	(43)
Net accrued pension liability included in Retirement Benefits in the Balance Sheet	$(63)	$(59)

A September 30, 1994 measurement da·, was used for 1994 reporting. At December 31, 199ʻ, the settlement (discount) rate and long-term rate of return on plan assets assumptions were 8.5% and 10 %, respectively. The long-term rate of annual compensati n increase assumption was 3.5% for 1995 and 1996 a d 4% thereafter. At December 31, 1993, the settlement rate and long-term rate of return on plan assets assu nptions were 7.25% and 8.75%, respectively. The long-term rate of annual compensation increase assumption was 4.25%.

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

(b) Other Postretirement Benefits

We sponsor a postretirement benefit plan which provides all employee groups certain health care, death and other postretirement benefits other than pensions. The plan is contributory, with retiree contributions adjusted annually. The plan is not funded. We adopted SFAS 106, the accounting standard for postretirement benefits other than pensions, effective January 1, 1993. The standard requires the accrual of the expected costs of such benefits

during the employees' years of service. Prior to 1993, the costs of these benefits were expensed as paid, which was consistent with ratemaking practices.

The components of the total postretirement benefit costs for 1994 and 1993 were as follows:

	1994	1993
	(millions of dollars)	
Service cost for benefits earned during the period	$ 2	$ 3
Interest cost on accumulated postretirement benefit obligation	18	16
Amortization of transition obligation at January 1, 1993 of $167 million over 20 years	8	8
VTP curtailment cost (includes $16 million transition obligation adjustment)	—	84
Total costs	$28	$111

In 1994 and 1993, we deferred incremental SFAS 106 expenses (in excess of the amounts paid) of $6 million and $96 million, respectively, pursuant to a provision of the Rate Stabilization Program. See Note 7.

The accumulated postretirement benefit obligation and accrued postretirement benefit cost are as follows:

	December 31, 1994	December 31, 1993
	(millions of dollars)	
Accumulated postretirement benefit obligation attributable to:		
Retired participants	$(203)	$(229)
Fully eligible active plan participants	(1)	(1)
Other active plan participants	(21)	(28)
Accumulated postretirement benefit obligation	(225)	(258)
Unrecognized net loss (gain) from variance between assumptions and experience	(23)	14
Unamortized transition obligation	135	143
Accrued postretirement benefit cost included in Retirement Benefits in the Balance Sheet	$(113)	$(101)

A September 30, 1994 measurement date was used for 1994 reporting. At December 31, 1994 and 1993, 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, 1994, the assumed annual health care cost trend rates (applicable to gross eligible charges) are 8.5% for medical and 8% for dental in 1995. 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, 1994 would increase by $7 million and the aggregate of the service and interest cost components of the annual postretirement benefit cost would increase by $0.5 million.

(10) Guarantees

Cleveland Electric has guaranteed certain loan and lease obligations of two coal suppliers under two long-term coal supply contracts. Toledo Edison is a party to one of these contracts. At December 31, 1994, the principal amount of the loan and lease obligations guaranteed by the Operating Companies under both contracts was $67 million. In addition, under the contract to which Toledo Edison is not a party, Cleveland Electric may be responsible for mine closing costs when the contract is terminated. At December 31, 1994, the unfunded costs of closing this mine as estimated by the supplier were $54 million.

The prices under both contracts which include certain minimum payments are sufficient to satisfy the loan and lease obligations and mine closing costs over the lives of the contracts. If either contract is terminated early for any reason, the Operating Companies would attempt to reduce the termination charges and would ask the PUCO to allow recovery of such charges from customers through the fuel factor of the respective Operating Company.

(11) Capitalization

(a) Capital Stock Transactions and Common Shares Reserved for Issue

Shares sold, retired and purchased for treasury during the three years ended December 31, 1994 are listed in the following table.

	1994	1993	1992
	(thousands of shares)		
Centerior Energy Common Stock:			
Dividend Reinvestment and Stock Purchase Plan	683	3,542	2,570
Employee Savings Plan	259	544	322
Employee Purchase Plan	46	52	—
Total Common Stock Sales	988	4,138	2,892
Treasury Shares	—	26	(172)
Net Increase	988	4,164	2,720
Preferred Stock of Subsidiaries Subject to Mandatory Redemption:			
Cleveland Electric Sales			
$90.00 Series S	—	—	75
Cleveland Electric Retirements			
$ 7.35 Series C	(10)	(10)	(10)
88.00 Series E	(3)	(3)	(3)
Adjustable Series M	(100)	(100)	(100)
9.125 Series N	(189)	(150)	—
Toledo Edison Retirements			
$100 par $11.00	—	—	(25)
9.375	(17)	(17)	(17)
25 par 2.81	(800)	(800)	—
Preferred Stock of Subsidiaries Not Subject to Mandatory Redemption:			
Cleveland Electric Sales			
$42.40 Series T	—	200	—
Cleveland Electric Retirements			
Remarketed Series P	—	—	(1)
Net (Decrease)	(1,119)	(880)	(81)

Shares of common stock required for our stock plans in 1994 were either acquired in the open market or issued as new shares.

The Board of Directors has authorized the purchase in the open market of up to 1,500,000 shares of our common stock until June 30, 1996. As of December 31, 1994, 225,500 shares had been purchased at a total cost of $4 million. Such shares are being held as treasury stock.

The number of common stock shares reserved for issue under the Employee Savings Plan and the Employee Purchase Plan was 1,702,849 and 423,797, respectively, at December 31, 1994.

Under an Equity Compensation Plan (Plan) adopted in 1994, options to purchase shares of common stock and restricted common stock awards were granted to management employees. Options were issued for 264,900 shares at an exercise price of $13.20. The options expire 10 years from the date of the grant and vest over four years. The number of shares available for issuance under the Plan each year is determined by formula, generally 0.5% of outstanding shares. The options and stock grants for 1994 are conditioned upon the approval of the Plan by Centerior Energy common stock share owners at their April 1995 annual meeting. Shares of common stock required for the Plan may be either issued as new shares, issued from treasury stock or acquired in the open market specifically for distribution under the Plan.

(b) Equity Distribution Restrictions

The Operating Companies make cash available for the funding of Centerior Energy's common stock dividends by paying dividends on their respective common stock, which are held solely by Centerior Energy. Federal law prohibits the Operating Companies from paying dividends out of capital accounts. However, the Operating Companies may pay preferred and common stock dividends out of appropriated retained earnings and current earnings. At December 31, 1994, Cleveland Electric and Toledo Edison had $144 million and $104 million, respectively, of appropriated retained earnings for the payment of dividends. However, Toledo Edison is prohibited from paying a common stock dividend by a provision in its mortgage 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 $47 million in 1995, $31 million in both 1996 and 1997, $16 million in 1998 and $35 million in 1999.

The annual mandatory redemption provisions are as follows:

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

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

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

The annualized preferred dividend requirement for the Operating Companies at December 31, 1994 was $63 million.

The preferred dividend rates on Cleveland Electric's Series L and M and Toledo Edison's Series A and B fluctuate based on prevailing interest rates and market conditions. The dividend rates for these issues averaged 7.17%, 7.01%, 7.66% and 8.44%, respectively, in 1994.

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

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

(d) Long-Term Debt and Other Borrowing Arrangements

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

Year of Maturity	Actual or Average Interest Rate at December 31, 1994	December 31, 1994	December 31, 1993
		(millions of dollars)	
First mortgage bonds:			
1996-1999	13.75 %	$ 17	$ 21
1996-1999	7.00	3	4
1997-1999	10.88	18	18
1997	6.125	31	31
1998	10.00	1	1
1999	6.20	2	2
1999	7.25	100	100
2000-2004	7.89	603	607
2005-2009	8.33	202	202
2010-2014	8.13	396	396
2015-2019	8.00	526	526
2020-2023	8.53	666	666
		2,565	2,574
Secured medium term notes due 1996-2021	8.60	766	963
Term bank loans due 1996	9.07	63	154
Notes due 1996-1997	9.49	25	43
Debentures due 2002	8.70	135	135
Pollution control notes due 1996-2015	10.30	151	158
Other — net	—	(8)	(8)
Total Long-Term Debt		$3,697	$4,019

Long-term debt matures during the next five years as follows: $326 million in 1995, $243 million in 1996, $95 million in 1997, $117 million in 1998 and $277 million in 1999.

The Operating Companies issued $266 million aggregate principal amount of secured medium-term notes in 1992 and 1993. The notes are secured by first mortgage bonds.

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

Certain unsecured loan agreements of the Operating Companies contain covenants relating to capitalization ratios, fixed charge coverage ratios and limitations on secured financing other than through first mortgage bonds or certain other transactions. Two reimbursement agreements relating to separate letters of credit issued in connection with the sale and leaseback of Beaver Valley Unit 2 contain several financial covenants affecting Centerior Energy and the Operating Companies. Among these are covenants relating to fixed charge coverage ratios and capitalization ratios. The write-offs recorded at December 31, 1993 caused Centerior Energy and the Operating Companies to violate certain covenants contained in a Cleveland Electric loan agreement and the two reimbursement agreements. The affected creditors waived those violations in exchange for a subordinate mortgage security interest on the Operating Companies' properties. We provided the same security interest to certain other creditors because their agreements require equal treatment. At December 31, 1994, the Operating Companies provided subordinate mortgage collateral for $197 million of unsecured debt, $228 million of bank letters of credit and a $205 million revolving credit facility.

(12) Short-Term Borrowing Arrangements

Centerior Energy has a $205 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 Operating Companies. Centerior Energy plans to transfer any of its borrowed funds to the Operating Companies. The facility agreement as amended provides the participating banks with a subordinate mortgage security interest on the Operating Companies' properties. 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, 1994. The facility agreement contains covenants relating to capitalization and fixed charge coverage ratios.

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

(13) Financial Instruments

Except for the Nuclear Plant Decommissioning Trusts at December 31 1994, as discussed below, the estimated fair values at December 31, 1994 and 1993 of financial instruments that do not approximate their carrying amounts in the Balance Sheet are as follows:

	December 31,			
	1994		1993	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(millions of dollars)			
Assets:				
Nuclear Plant Decommissioning Trusts	$ 82	$ 82	$ 56	$ 59
Capitalization and Liabilities:				
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	300	264	354	349
Long-Term Debt (including current portion)	4,031	3,628	4,113	4,260

The Nuclear Plant Decommissioning Trusts at December 31, 1994 included $46 million of federal governmental securities and $31 million of municipal securities. The securities had the following maturities: $19 million due within one year; $16 million due in one to five years; $17 million due in six to 10 years; and $25 million due after 10 years. 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 is equal to the fair value. The fair value of the Operating Companies' preferred stock, with mandatory redemption provisions, and long-term debt is estimated based on the quoted market prices for the respective or similar issues or on the basis of the discounted value of future cash flows. The discounted value used current dividend or interest rates (or other appropriate rates) for similar issues and loans with the same remaining maturities.

The estimated fair values of all other financial instruments approximate their carrying amounts in the Balance Sheet at December 31, 1994 and 1993 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, 1994.

	Quarters Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
	(millions of dollars, except per share amounts)			
1994				
Operating Revenues	$588	$596	$667	$ 570
Operating Income	$129	$134	$186	$ 129
Net Income	$ 35	$ 42	$ 92	$ 35
Average Common Shares (millions)	147.4	147.9	148.0	148.0
Earnings Per Common Share	$ .24	$ .28	$ .62	$ .24
Dividends Paid Per Common Share	$ .20	$ .20	$ .20	$ .20
1993				
Operating Revenues	$598	$589	$709	$ 578
Operating Income (Loss)	$122	$126	$106	$ (42)
Net Income (Loss)	$ 35	$ 34	$ 17	$(1,029)
Average Common Shares (millions)	143.4	144.4	145.3	146.4
Earnings (Loss) Per Common Share	$ .25	$ .23	$ .12	$ (7.02)
Dividends Paid Per Common Share	$ .40	$ .40	$ .40	$ .40

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

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

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
1994	$758	722	758	137	2 375	46	2 421	—	$2 421
1993	768	716	754	143	2 381	93	2 474	—	2 474
1992	732	706	766	143	2 347	91	2 438	—	2 438
1991	777	723	783	188	2 471	89	2 560	—	2 560
1990	719	669	779	190	2 357	70	2 427	—	2 427
1984	548	454	636	88	1 726	24	1 750	24	1 774

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	Total Operating Expenses
1994	$442	595	160	278	309	(55)	114	$1 843
1993	474	924 *(a)*	159	258	312	23 *(b)*	11	2 161
1992	473	623	161	256	318	(52)	122	1 901
1991	500	633	168	243 *(c)*	305	(6)	138	1 981
1990	472	698	165	242	283	(34)	96	1 922
1984	463	404	—	145	179	—	198	1 389

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	Debt Interest
1994	$578	5	8	40	(6)	625	361
1993	313	5	(589) *(d)*	(649) *(b)*	398	(522)	359
1992	537	2	9	100	(7)	641	365
1991	579	9	6	110	(30)	674	381
1990	505	8	(1)	205	(13)	704	384
1984	385	213	12	—	69	679	310

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

Year	AFUDC—Debt	Preferred & Preference Stock Dividends	Net Income (Loss)	Average Shares Outstanding (millions)	Earnings (Loss)	Return on Average Common Stock Equity	Dividends Declared	Book Value
1994	$ (6)	66	$ 204	147.8	$ 1.38	11.1 %	$ .80	$12.71
1993	(5)	67	(943)	144.9	(6.51)	(40.3)	1.60	12.14
1992	(1)	65	212	141.7	1.50	7.4	1.60	20.22
1991	(5)	61	237	139.1	1.71	8.4	1.60	20.37
1990	(6)	62	264	138.9	1.90	9.4	1.60	20.30
1984	(76)	78	367	107.6 *(e)*	3.41 *(e)*	16.4	2.29 *(e)*	20.64 *(e)*

NOTE: 1984 data is the result of combining and restating data for the Operating Companies.

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

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

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

	Electric Sales (millions of KWH)						Electric Customers (year end)				Residential Usage		
Year	Residential	Commercial	Industrial	Wholesale	Other	Total	Residential	Commercial	Industrial & Other	Total	Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
1994	6 980	7 481	12 069	1 842	1 074	29 446	925 344	97 530	11 360	1 034 234	7 556	10.86¢	$820.89
1993	6 974	7 306	11 687	3 027	1 022	30 016	924 227	96 491	12 219	1 032 937	7 546	11.01	830.99
1992	6 666	7 086	11 551	2 814	1 011	29 128	925 099	96 813	12 741	1 034 653	7 227	10.98	793.68
1991	6 981	7 176	11 559	2 690	1 048	29 454	921 995	96 449	12 843	1 031 287	7 410	11.16	827.10
1990	6 666	6 848	12 168	2 487	959	29 128	918 965	94 522	12 906	1 026 393	7 079	10.82	765.93
1984	6 404	5 794	11 441	578	871	25 088	888 816	85 825	11 850	986 491	7 035	8.56	603.92

	Load (MW & %)				Energy (millions of KWH)					Fuel	
					Company Generated						
Year	Net Seasonal Capability	Peak Load	Capacity Margin	Load Factor	Fossil	Nuclear	Total	Purchased Power	Total	Fuel Cost Per KWH	Efficiency—BTU Per KWH
1994	6 226	5 291	15.0%	63.9%	18 146	11 824	29 970	922	30 892	1.35¢	10 454
1993	6 226	5 397	13.3	61.6	21 105	10 435	31 540	273	31 813	1.39	10 276
1992	6 463	5 091	21.2	63.4	17 371	13 814	31 185	(122)	31 063	1.45	10 395
1991	6 460	5 361	17.0	62.9	18 041	13 454	31 495	40	31 535	1.48	10 442
1990	6 437	5 261	18.3	63.6	21 114	9 481	30 595	413	31 008	1.52	10 354
1984	5 384	4 659	13.5	66.1	19 930	4 303	24 233	2 621	26 854	1.71	10 349

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
1994	$9 770	2 906	6 864	129	343	$7 336	$197	$10 691
1993	9 571	2 677	6 894	181	385	7 460	218	10 710
1992	9 449	2 488	6 961	781	424	8 166	200	12 071
1991	8 888	2 274	6 614	853	503	7 970	204	11 829
1990	8 636	2 039	6 597	921	568	8 086	251	11 681
1984	4 282	1 164	3 118	3 527	485*(f)*	7 130	939	8 050

Capitalization (millions of dollars & %)

Year	Common Stock Equity		Preferred & Preference Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
1994	$1 882	30%	253	4%	451	7%	3 697	59%	$6 283
1993	1 785	27	313	5	451	7	4 019	61	6 568
1992	2 889	39	364	5	354	5	3 694	51	7 301
1991	2 855	38	332	4	427	6	3 841	52	7 455
1990	2 810	39	237	3	427	6	3 729	52	7 203
1984	2 403	39	451	7	344	6	2 994	48	6 192

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

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

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

Report of Independent Public Accountants

To the Share Owners and
Board of Directors of
The Cleveland Electric Illuminating Company:

We have audited the accompanying consolidated balance sheet and consolidated statement of preferred stock of The Cleveland Electric Illuminating Company (a wholly owned subsidiary of Centerior Energy Corporation) and subsidiaries as of December 31, 1994 and 1993, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1994. These financial statements and the schedule referred to below are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Cleveland Electric Illuminating Company and subsidiaries as of December 31, 1994 and 1993, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1994, 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.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule of The Cleveland Electric Illuminating Company and subsidiaries listed in the Index to Schedules is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Cleveland, Ohio
February 17, 1995

Management's Financial Analysis

Outlook

Strategic Plan

We made significant strides in achieving the objectives of the comprehensive strategic action plan announced in January 1994. Centerior Energy Corporation (Centerior Energy), along with The Cleveland Electric Illuminating Company (Company) and The Toledo Edison Company (Toledo Edison), created the strategic plan to strengthen their financial and competitive position through the year 2001. The Company and Toledo Edison 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 an industry 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. To achieve these objectives, we will continue to control expenditures and reduce our outstanding debt and preferred stock. In addition, we will increase revenues by finding new uses for existing assets and resources, implementing new marketing programs and restructuring rates when appropriate. We will also improve the operating performance of our generating plants and take other appropriate actions.

During 1994, we made progress toward most of our long-term objectives. The Company and Toledo Edison initiated a marketing plan designed to increase total retail revenues (exclusive of fuel cost recovery revenues and weather influences) by 2-3% annually through 2001. Our new customer service activities are intended to raise our customer satisfaction rating. Our employees achieved enough of their established objectives for the year to receive a $500 per eligible employee incentive compensation award. The work undertaken during refueling outages at the Davis-Besse Nuclear Power Station (Davis-Besse) and Perry Nuclear Power Plant Unit 1 (Perry Unit 1) as well as the outage work at our fossil-fueled plants should help us achieve our long-term objective of reducing variable power costs to a more competitive level. Strong cash flow continued in 1994 and the Company's fixed-income obligations were reduced by $77 million. Also, the Company's total operation and maintenance expenses declined $71 million, exclusive of one-time charges in 1993.

We are taking aggressive steps to increase revenues through our enhanced marketing plan and to control costs. The full impact of these efforts will take time. In the meantime, the Company and Toledo Edison must raise revenues by restructuring rates. Accordingly, the Company and Toledo Edison are preparing to file a request with The Public Utilities Commission of Ohio (PUCO) to be effective in 1996. Meaningful cost control and marketing strategies will mitigate the need for additional rate increases and help us meet competition.

Competition

We are implementing strategies designed to create and enhance our competitive advantages and to overcome the competitive disadvantages that we face due to regulatory and tax constraints and our high retail cost structure.

Currently our most pressing competition comes from two municipal electric systems in our service area. Our rates are generally higher than those of the two municipal systems due largely to their exemption from taxation, the lower cost financing available to them, the continued availability to them of lower cost power through short-term power purchases and their access to cheaper governmental power. We are seeking to address the tax disparity through the legislative process. In 1994, the Ohio Governor's Tax Commission recommended the replacement of the gross receipts and personal property taxes currently levied only on investor-owned utilities and collected through rates with a different tax collected from customers of all electric utilities, including municipal systems. Investor-owned utilities would reduce rates upon repeal of the existing taxes. We are now working to submit this proposal to the Ohio legislature.

We face the threat that municipalities in our service area could establish new systems and continue expanding existing systems. We are responding with aggressive marketing programs and by emphasizing the value of our service and the risks of a municipal system: substantial, long-term debt; no guarantee of low-cost wholesale electricity; the difficulty of forecasting costs; and the uncertainty of market share as a result of our aggressive competition. Generally, these municipalities have determined that developing a system is not feasible or have agreed with us not to pursue development of a system at this time. Although some communities continue to be interested in municipalization, we believe that we offer the best value and most reliable source of electric service in our territory.

The larger municipal system in our service area, Cleveland Public Power (CPP), is constructing new transmission and distribution facilities extending into eastern portions of Cleveland. CPP also plans to expand to western portions of Cleveland. CPP's expansion reduced our annual net income by about $4 million in 1993 and an additional $3 million in 1994. We estimate our net income will continue to be reduced by an additional $4 million to $5 million each year in the 1995-1999 period because of CPP's expansion. Despite CPP's expansion efforts, we have been successful in retaining most of the large industrial and commercial customers in the expansion areas by providing economic incentives in exchange for sole-supplier contracts. We have similar contracts

with customers in other parts of our service area. Approximately 90% of our industrial revenues under contract will not be up for renewal until 1997 or later. As these contracts expire, we expect to renegotiate them and retain the customers. In addition, an increasing number of CPP customers are converting back to our service.

The Energy Policy Act of 1992 will increase competition in the electric utility industry by allowing broader access to a utility's transmission system. It should not significantly increase the competitive threat to us since we have been required to wheel electricity to municipal systems in our service area since 1977 under operating licenses for our nuclear generating units. Further, the government could eventually require utilities to deliver power from other utilities or generation sources to their retail customers. To combat this threat, we are offering incentives such as energy-efficiency improvements and reductions in demand charges for increased electricity usage to our industrial and commercial customers in return for long-term commitments.

Rate Matters

Under the Rate Stabilization Program discussed in Note 7, we agreed to freeze base rates until 1996 and limit rate increases through 1998. In exchange, we are permitted to defer through 1995 and subsequently recover certain costs not currently recovered in rates and to accelerate the amortization of certain benefits. Amortization and recovery of the deferrals are expected to begin in 1996 with future rate recognition and will continue over the average life of the related assets, or between 17 and 30 years. The continued use of these regulatory accounting measures in 1995 will be dependent upon our continuing assessment and conclusion that there will be probable recovery of such deferrals in future rates. Our analysis leading to certain year-end 1993 financial actions and the strategic plan also included an evaluation of our regulatory accounting measures. See Regulatory Accounting below and Note 7. We decided that, once the deferral of expenses and acceleration of benefits under the Rate Stabilization Program are completed in 1995, we should no longer plan to use these measures to the extent we have in the past.

Regulatory Accounting

As described in Notes 1(a) and 7, the Company complies with the provisions of Statement of Financial Accounting Standards (SFAS) 71. We continually 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 establish rates to recover operating costs, return requirements and the amortization of regulatory assets and (2) a significant change in the manner in which rates are set by the PUCO from cost-based regulations to some other form of regulations. In the event we determine that the Company no longer meets the criteria for following SFAS 71, the Company would be required to record a before-tax charge to write off the regulatory assets shown in Note 7. 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 would also result in an impairment of the net book value of the Company's property, plant and equipment.

The Company's write-off in 1993 of the phase-in deferred operating expenses and carrying charges (phase-in deferrals) discussed in Note 7 resulted from our conclusion that projected revenues for the 1994-1998 period would not provide for recovery of such deferrals as scheduled by the PUCO order. This short time frame for recovery of the phase-in deferrals is a requirement under the accounting standard for phase-in plans of regulated enterprises, SFAS 92. The remaining recovery periods for all remaining regulatory assets are between 17 and 34 years. We believe the Company's rates will provide for recovery of these assets over the relevant periods and SFAS 71 continues to apply.

Nuclear Operations

The Company has interests in three nuclear generating units — Davis-Besse, Perry Unit 1 and Beaver Valley Power Station Unit 2 (Beaver Valley Unit 2). Toledo Edison operates Davis-Besse and the Company operates Perry Unit 1. Davis-Besse and Beaver Valley Unit 2 have been operating extremely well, with each unit having a three-year availability average at year-end 1994 that exceeded the three-year industry average of 80% for similar reactors. However, the three-year availability average of Perry Unit 1 was below the three-year industry availability average for that reactor type.

In 1994, Davis-Besse had an availability factor of 88%. Further, Davis-Besse completed the shortest refueling and maintenance outage in its history in 1994, returning to service just 46 days after shutting down. The Company is in the process of upgrading Perry Unit 1 to the same level. For seven months in 1994, Perry Unit 1 was out of service for its fourth refueling and maintenance outage. Work was also performed in connection with the comprehensive course of action developed in 1993 to improve the operating performance of Perry Unit 1. Work in connection with that course of action is ongoing.

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 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.

Hazardous Waste Disposal Sites

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended (Superfund) established programs addressing the cleanup of hazardous waste disposal sites, emergency preparedness and other issues. The Company has been named as a "potentially responsible party" (PRP) for three sites listed on the Superfund National Priorities List (Superfund List) and is aware of its potential involvement in the cleanup of several other sites. Allegations that the Company disposed of hazardous waste at these sites, and the amounts involved, are often unsubstantiated and subject to dispute. Superfund provides that all PRPs for a particular site can 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 $350 million. However, we believe that the actual cleanup costs will be substantially lower than $350 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 $8 million at December 31, 1994 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

Centerior Energy's common stock dividend has been funded in recent years primarily by common stock dividends paid by the Company. We expect this practice to continue for the foreseeable future. In 1994, Centerior Energy lowered its common stock dividend which reduced its cash outflow by over $110 million annually. This action, in turn, reduced the common stock cash dividend demand on the Company. The Company is using the increased retained cash to redeem debt and preferred stock more quickly than would otherwise be the case. This has helped improve the Company's capitalization structure and fixed charge coverage ratios.

Merger of Toledo Edison into the Company

We continue to seek the necessary regulatory approvals to complete the merger of Toledo Edison into the Company which was announced in 1994. The Company and Toledo Edison plan to seek preferred stock share owner approval in mid-1995. The merger is expected to be effective in 1995. See Note 15.

Inflation

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

Capital Resources and Liquidity

1992-1994 Cash Requirements

We need cash for normal corporate operations, the mandatory retirement of securities and constructing and modifying facilities. Construction is needed to meet anticipated demand for electric service, comply with government regulations and protect the environment. Over the three-year period 1992-1994, construction and mandatory retirement needs totaled approximately $940 million. In addition, we exercised options to redeem and purchase approximately $470 million of our securities.

We raised $989 million through security issues and term bank loans during the 1992-1994 period. The Company also utilized short-term borrowings to help meet its cash needs. The Company had $58 million of notes payable to affiliates at December 31, 1994. See Note 12. Although write-offs of the Company's Perry Nuclear Power Plant Unit 2 (Perry Unit 2) investment and phase-in deferrals in 1993 negatively affected earnings, they did not adversely affect cash flow. See Notes 4(b) and 7.

1995 and Beyond Cash Requirements

Estimated cash requirements for 1995-1999 for the Company are $802 million for construction and $832 million for the mandatory redemption of debt and preferred stock. The Company expects to finance externally about two-thirds of its 1995 cash requirements of approximately $451 million and about one-third of its 1996 cash requirements of approximately $320 million. The Company expects to meet nearly all of its 1997-1999 requirements through internal cash generation and current cash resources. If economical, additional securities may be redeemed under optional redemption provisions. We expect that the Company's continued strong cash flow

will reduce borrowing requirements and outstanding debt and preferred stock during this period.

Cash expenditures to comply with the Clean Air Act Amendments of 1990 (Clean Air Act) are estimated to be approximately $65 million over the 1995-1999 period. See Note 4(a).

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, 1994, the Company would have been permitted to issue approximately $487 million of additional first mortgage bonds.

The Company also is able to raise funds through the sale of subordinated debt and preferred and preference stock. There are no restrictions on the Company's ability to issue preferred or preference stock.

In 1995, the Company plans to raise funds through the sale of first mortgage bonds and the collateralization of accounts receivable. In addition, the Company expects to issue first mortgage bonds as collateral security for the sale by a public authority of tax-exempt bonds.

The Company is a party to a $205 million revolving credit facility which runs through mid-1996. See Note 12. The Company had $66 million of cash and temporary cash investments at the end of 1994. The Company is unable to issue commercial paper because of its below investment grade commercial paper ratings.

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
Unsecured notes	B+	Ba3
Preferred stock	B	b2

Results of Operations

1994 vs. 1993

Factors contributing to the 3% decrease in 1994 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$ 2
Wholesale Revenues	(48)
Fuel Cost Recovery Revenues	(13)
Miscellaneous Revenues	6
Total	$(53)

The Company experienced good retail kilowatt-hour sales growth in the commercial and industrial categories in 1994; the residential category was negatively impacted by weather conditions, particularly during the summer. The revenue decrease resulted primarily from milder weather conditions in 1994 and 53% lower wholesale sales. Weather reduced base rate revenues approximately $8 million from the 1993 amount. Although total sales decreased by 4.6%, commercial sales increased 2.4%. Industrial sales increased 0.7% 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 Northeastern Ohio. Residential sales declined 0.2% because of the weather factor. Other sales decreased by 42% because of the lower sales to wholesale customers attributable to expiration of a wholesale power agreement, softer wholesale market conditions and limited power availability for bulk power transactions at certain times because of generating plant outages. Lower 1994 fuel cost recovery revenues resulted from favorable changes in the fuel cost factors. The weighted average of these factors dropped by approximately 5%.

For 1994, operating revenues were 31% residential, 32% commercial, 30% industrial and 7% other and kilowatt-hour sales were 24% residential, 29% commercial, 39% industrial and 8% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.09 and $.06, respectively.

Operating expenses were 15% lower in 1994. Operation and maintenance expenses for 1993 included $130 million of net benefit expenses related to an early retirement program, called the Voluntary Transition Program (VTP), and other charges totaling $35 million. The VTP benefit expenses in 1993 consisted of $102 million of costs for the Company plus $28 million for the Company's pro rata share of the costs for its affiliate, Centerior Service Company (Service Company). Two other significant reasons for lower operation and maintenance expenses in 1994 were a smaller work force and ongoing cost reduction measures. More nuclear generation and less coal-fired generation accounted for a large part of the lower fuel and purchased power expenses in 1994. 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 $117 million of phase-in deferred operating expenses in 1993 as discussed in Note 7. The 1993 deferrals also

included $52 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), $351 million of our Perry Unit 2 investment was written off in 1993. Also, as discussed in Note 7, phase-in deferred carrying charges of $519 million were written off in 1993. The change in the federal income tax credit amounts for nonoperating income was attributable to these write-offs.

1993 vs. 1992

Factors contributing to the 0.5% increase in 1993 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$ 27
Fuel Cost Recovery Revenues	(13)
Base Rates and Miscellaneous	(10)
Wholesale Sales	4
Total	$ 8

The revenue increase resulted primarily from the different weather conditions and the changes in the composition of the sales mix among customer categories. Weather accounted for approximately $32 million of higher 1993 base rate revenues. Hot summer weather in 1993 boosted residential, commercial and wholesale kilowatt-hour sales. In contrast, the 1992 summer was the coolest in 56 years for Northeastern Ohio. Residential and commercial sales also increased as a result of colder late-winter temperatures in 1993 which increased electric heating-related demand. As a result, total sales increased 2.9% in 1993. Residential and commercial sales increased 4.4% and 3.1%, respectively. Industrial sales decreased 1%. Lower sales to large steel industry customers were partially offset by increased sales to large automotive manufacturers and the broad-based, smaller industrial customer group. Other sales increased 12% because of increased sales to wholesale customers. The decrease in 1993 fuel cost recovery revenues resulted from changes in the fuel cost factors. The weighted average of these factors decreased approximately 5%. Base rates and miscellaneous revenues decreased in 1993 primarily from lower revenues under contracts having reduced rates with certain large customers and a declining rate structure tied to usage. The contracts have been negotiated to meet competition and encourage economic growth.

For 1993, operating revenues were 31% residential, 31% commercial, 29% industrial and 9% other and kilowatt-hour sales were 23% residential, 27% commercial, 37% industrial and 13% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.10 and $.06, respectively. The changes from 1992 were not significant.

Operating expenses increased 12% in 1993. The increase in total operation and maintenance expenses resulted from the $130 million of net benefit expenses related to the VTP, other charges totaling $35 million and an increase in other operation and maintenance expenses. The increase in other operation and maintenance expenses resulted from higher environmental expenses, power restoration and repair expenses following a July 1993 storm, and an increase in other postretirement benefit expenses. See Note 9 for information on retirement benefits. Deferred operating expenses decreased because of the write-off of the phase-in deferred operating expenses in 1993. Federal income taxes decreased as a result of lower pretax operating income.

As mentioned above, $351 million of our Perry Unit 2 investment was written off in 1993. Credits for carrying charges recorded in nonoperating income decreased because of the write-off of the phase-in deferred carrying charges in 1993. The federal income tax credit for nonoperating income in 1993 resulted from the write-offs.

Income Statement

The Cleveland Electric Illuminating Company and Subsidiaries

	For the years ended December 31,		
	1994	1993	1992
		(millions of dollars)	
Operating Revenues	$1,698	$1,751	$1,743
Operating Expenses			
Fuel and purchased power (1)	391	423	434
Other operation and maintenance	394	433	410
Generation facilities rental expense, net	56	56	55
Early retirement program expenses and other	—	165	—
Total operation and maintenance	841	1,077	899
Depreciation and amortization	195	182	179
Taxes, other than federal income taxes	218	221	226
Deferred operating expenses, net	(34)	27	(35)
Federal income taxes	82	22	89
	1,302	1,529	1,358
Operating Income	396	222	385
Nonoperating Income (Loss)			
Allowance for equity funds used during construction	4	4	1
Other income and deductions, net	6	(5)	8
Write-off of Perry Unit 2	—	(351)	—
Deferred carrying charges, net	25	(487)	59
Federal income taxes — credit (expense)	(4)	270	(5)
	31	(569)	63
Income (Loss) Before Interest Charges	427	(347)	448
Interest Charges			
Debt interest	247	244	243
Allowance for borrowed funds used during construction	(5)	(4)	—
	242	240	243
Net Income (Loss)	185	(587)	205
Preferred Dividend Requirements	45	45	41
Earnings (Loss) Available for Common Stock	$ 140	$ (632)	$ 164

(1) Includes purchased power expense of $111 million, $120 million and $130 million in 1994, 1993 and 1992, respectively, for all purchases from Toledo Edison.

Retained Earnings

	For the years ended December 31,		
	1994	1993	1992
		(millions of dollars)	
Retained Earnings (Deficit) at Beginning of Year	$(280)	$ 545	$ 578
Additions			
Net income (loss)	185	(587)	205
Deductions			
Dividends declared:			
Common stock	(122)	(189)	(195)
Preferred stock	(45)	(48)	(41)
Other, primarily preferred stock redemption expenses	—	(1)	(2)
Net Increase (Decrease)	18	(825)	(33)
Retained Earnings (Deficit) at End of Year	$(262)	$(280)	$ 545

The accompanying notes are an integral part of these statements.

Balance Sheet

	December 31, 1994	December 31, 1993
	(millions of dollars)	
ASSETS		
Property, Plant and Equipment		
Utility plant in service	$6,871	$6,734
Less: accumulated depreciation and amortization	2,014	1,889
	4,857	4,845
Construction work in progress	99	141
	4,956	4,986
Nuclear fuel, net of amortization	174	202
Other property, less accumulated depreciation	21	41
	5,151	5,229
Current Assets		
Cash and temporary cash investments	66	77
Amounts due from customers and others, net	146	156
Amounts due from affiliates	5	5
Unbilled revenues	72	99
Materials and supplies, at average cost	95	93
Fossil fuel inventory, at average cost	16	20
Taxes applicable to succeeding years	180	179
Other	4	3
	584	632
Deferred Charges and Other Assets		
Amounts due from customers for future federal income taxes	641	586
Unamortized loss on reacquired debt	58	60
Carrying charges and operating expenses	578	519
Nuclear plant decommissioning trusts	44	30
Other	95	103
	1,416	1,298
Total Assets	$7,151	$7,159

The accompanying notes are an integral part of this statement.

	December 31, 1994	December 31, 1993
	(millions of dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shares, without par value: 105 million authorized; 79.6 million outstanding in 1994 and 1993	$1,241	$1,241
Other paid-in-capital	79	79
Retained earnings (deficit)	(262)	(280)
Common stock equity	1,058	1,040
Preferred stock		
With mandatory redemption provisions	246	285
Without mandatory redemption provisions	241	241
Long-term debt	2,543	2,793
	4,088	4,359
Current Liabilities		
Current portion of long-term debt and preferred stock	282	70
Current portion of nuclear fuel lease obligations	47	63
Accounts payable	88	122
Accounts and notes payable to affiliates	118	61
Accrued taxes	310	305
Accrued interest	62	60
Other	51	52
	958	733
Deferred Credits and Other Liabilities		
Unamortized investment tax credits	192	235
Accumulated deferred federal income taxes	1,234	1,105
Unamortized gain from Bruce Mansfield Plant sale	327	343
Accumulated deferred rents for Bruce Mansfield Plant	84	77
Nuclear fuel lease obligations	132	151
Retirement benefits	59	52
Other	77	104
	2,105	2,067
Total Capitalization and Liabilities	$7,151	$7,159

Cash Flows

	For the years ended December 31,		
	1994	1993	1992
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income (Loss)	$ 185	$(587)	$ 205
Adjustments to Reconcile Net Income (Loss) to Cash from Operating Activities:			
Depreciation and amortization	195	182	179
Deferred federal income taxes	50	(292)	66
Investment tax credits, net	—	—	(8)
Unbilled revenues	27	(6)	(7)
Deferred fuel	(20)	4	6
Deferred carrying charges, net	(25)	487	(59)
Leased nuclear fuel amortization	55	47	70
Deferred operating expenses, net	(34)	27	(35)
Allowance for equity funds used during construction	(4)	(4)	(1)
Noncash early retirement program expenses, net	—	125	—
Write-off of Perry Unit 2	—	351	—
Changes in amounts due from customers and others, net	10	5	6
Changes in inventories	2	17	(2)
Changes in accounts payable	(34)	18	7
Changes in working capital affecting operations	3	29	(4)
Other noncash items	4	5	(11)
Total Adjustments	229	995	207
Net Cash from Operating Activities	414	408	412
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	—	(10)	10
Notes payable to affiliates	58	(11)	(13)
First mortgage bond issues	46	280	324
Secured medium-term note issues	—	35	90
Term bank loan	—	40	—
Preferred stock issues	—	100	74
Maturities, redemptions and sinking funds	(116)	(345)	(481)
Nuclear fuel lease obligations	(60)	(59)	(65)
Dividends paid	(142)	(232)	(235)
Premiums, discounts and expenses	(1)	(11)	(7)
Net Cash from Financing Activities	(215)	(213)	(303)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(164)	(167)	(152)
Interest capitalized as allowance for borrowed funds used during construction	(5)	(4)	—
Contributions to nuclear plant decommissioning trusts	(14)	(5)	(5)
Other cash received (applied)	(27)	24	(15)
Net Cash from Investing Activities	(210)	(152)	(172)
Net Change in Cash and Temporary Cash Investments	(11)	43	(63)
Cash and Temporary Cash Investments at Beginning of Year	77	34	97
Cash and Temporary Cash Investments at End of Year	$ 66	$ 77	$ 34

(1) Interest paid (net of amounts capitalized) was $208 million, $204 million and $205 million in 1994, 1993 and 1992, respectively. Income taxes paid were $15 million in 1994 and $28 million in both 1993 and 1992.

(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 p[illegible] this statement.

Statement of Preferred Stock

	1994 Shares Outstanding	Current Call Price Per Share	December 31, 1994	December 31, 1993
			(millions of dollars)	
Without par value, 4,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$ 7.35 Series C	140,000	$ 101.00	$ 14	$ 15
88.00 Series E	18,000	1,019.13	18	21
Adjustable Series M	100,000	100.00	10	20
9.125 Series N	410,766	102.03	41	59
91.50 Series Q	75,000	—	75	75
88.00 Series R	50,000	—	50	50
90.00 Series S	75,000	—	74	74
			282	314
Less: Current maturities			36	29
Total Preferred Stock, with Mandatory Redemption Provisions			$246	$285
Not subject to mandatory redemption:				
$ 7.40 Series A	500,000	101.00	$ 50	$ 50
7.56 Series B	450,000	102.26	45	45
Adjustable Series L	500,000	100.00	49	49
42.40 Series T	200,000	—	97	97
Total Preferred Stock, without Mandatory Redemption Provisions			$241	$241

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's financial statements have historically included the accounts of the Company's wholly owned subsidiaries, which in the aggregate were not material. During 1994, the Company transferred its investments in its three wholly owned subsidiaries to Centerior Energy at cost ($26 million) via property dividends.

The Company follows the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (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 Company is a member of the Central Area Power Coordination Group (CAPCO). Other members are Toledo Edison, Duquesne Light Company, Ohio Edison Company and its wholly owned subsidiary, Pennsylvania Power Company. The members have constructed and operate generation and transmission facilities for their use.

(b) 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 Toledo Edison 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 $136 million, $167 million and $150 million in 1994, 1993 and 1992, 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. 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 Amortization

The cost of property, plant and equipment is depreciated over their estimated useful lives on a straight-line basis. The annual straight-line depreciation provision for nonnuclear property expressed as a percent of average depreciable utility plant in service was 3.4% in 1994, 1993 and 1992. The annual straight-line depreciation rate for nuclear property is 2.5%.

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 allowing net earnings to 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 $13 million from the $4 million level in 1992. The accruals are reflected in current rates. The increased accruals were derived from recently updated, site-specific studies for each of the units. The revised estimates reflect the DECON method of decom-

missioning (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	\$178(1)	\$ 443
Perry Unit 1	2026	156(1)	554
Beaver Valley Unit 2	2027	63(2)	233
Total		\$397	\$1,230

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

The updated estimates reflect substantial increases from the prior PUCO-recognized aggregate estimates of \$142 million in 1987 and 1986 dollars.

The classification, Accumulated Depreciation and Amortization, in the Balance Sheet at December 31, 1994 includes \$53 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 is reviewing the accounting for removal costs, including decommissioning. If such 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.

(f) Property, Plant and Equipment

Property, plant and equipment are stated at original cost less amounts ordered by the PUCO to be written off. Construction costs include related payroll taxes, 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 9.68% in 1994, 9.63% in 1993 and 10.56% in 1992.

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 from Sale of Utility Plant

The sale and leaseback transaction discussed in Note 2 resulted in a net gain for the sale of the Bruce Mansfield Generating Plant (Mansfield Plant). The net gain was deferred and is being amortized over the term of leases. The amortization 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. Such losses and gains are either amortized over the remainder of the original life of the debt issue retired or amortized over the life of the new debt issue when the proceeds of a new issue are used for the debt redemption. The amortizations are included in debt interest expense.

(i) Federal Income Taxes

The 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.

Investment tax credits are deferred and amortized over the lives of the applicable property as a reduction of

depreciation expense. See Note 7 for a discussion of the amortization of certain unrestricted excess deferred taxes and unrestricted investment tax credits under the Rate Stabilization Program.

(2) Utility Plant Sale and Leaseback Transactions

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

Under these leases, the Company and Toledo Edison 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 Toledo Edison 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. Additional lease provisions provide other purchase options along with conditions for mandatory termination of the leases (and possible repurchase of the leasehold interests) for events of default. These events include noncompliance with any of several financial covenants discussed in Note 11(d).

As co-lessee with Toledo Edison, the Company is also obligated for Toledo Edison's lease payments. If Toledo Edison is unable to make its payments under the Beaver Valley Unit 2 and Mansfield Plant leases, the Company would be obligated to make such payments. No such payments have been made on behalf of Toledo Edison.

Future minimum lease payments under the operating leases at December 31, 1994 are summarized as follows:

Year	For the Company	For Toledo Edison
	(millions of dollars)	
1995	$ 63	$ 103
1996	63	125
1997	63	102
1998	63	102
1999	70	108
Later Years	1,321	1,918
Total Future Minimum Lease Payments	$1,643	$2,458

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1994, 1993 and 1992 as annual rental expense for the Mansfield Plant leases was $70 million. Amounts charged to expense in excess of the lease payments are classified as Accumulated Deferred Rents in the Balance Sheet.

The Company is buying 150 megawatts of Toledo Edison's Beaver Valley Unit 2 leased capacity entitlement. Purchased power expense for this transaction was $108 million, $103 million and $108 million in 1994, 1993 and 1992, respectively. We anticipate that this purchase will continue indefinitely. The future minimum lease payments through the year 2017 associated with Beaver Valley Unit 2 aggregate $1.413 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, 1994 includes the following facilities owned by the Company as a tenant in common with other utilities and Lessors:

Generating Unit	In-Service Date	Ownership Share	Ownership Megawatts	Power Source	Plant in Service	Construction Work in Progress	Accumulated Depreciation
						(millions of dollars)	
Seneca Pumped Storage	1970	80.00%	351	Hydro	$ 66	$—	$ 22
Eastlake Unit 5	1972	68.80	411	Coal	156	1	—
Davis-Besse	1977	51.38	454	Nuclear	664	2	190
Perry Unit 1	1987	31.11	371	Nuclear	1,774	5	314
Beaver Valley Unit 2 and Common Facilities (Note 2)	1987	24.47	201	Nuclear	1,276	2	250
Total					$3,936	$10	$776

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

(4) Construction and Contingencies

(a) Construction Program

The estimated cost of the Company's construction program for the 1995-1999 period is $851 million, including AFUDC of $49 million and excluding nuclear fuel.

The 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 1994 in connection with Clean Air Act compliance amounted to $34 million. The plan will require additional capital expenditures over the 1995-2004 period of approximately $125 million for nitrogen oxide control equipment and plant modifications. In addition, higher fuel and other operation and maintenance expenses will be incurred. The anticipated rate increase associated with the capital expenditures and higher expenses would be about 1-2% in the late 1990s. The Company may need to install sulfur emission control technology at one of its generating plants after 2005 which could require additional expenditures at that time.

(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 $351 million ($258 million after taxes) for the Company's 44.85% ownership share of the unit. See Note 14.

(c) Hazardous Waste Disposal Sites

The Company is aware of its potential involvement in the cleanup of three sites listed on the Superfund List and several other waste sites not on such list. The Company has accrued a liability totaling $8 million at December 31, 1994 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 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 $85 million (plus any inflation adjustment) per incident. The assessment is limited to $11 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, 1995. 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. Under these policies, the Company can be assessed a maximum of $12 million during a policy year if the reserves available to the insurer are inadequate to pay claims arising out of an accident at any nuclear facility covered by the insurer.

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 Toledo Edison through leases with a special-purpose corporation. At December 31, 1994, $307 million ($182 million for the Company and $125 million for Toledo Edison) of nuclear fuel was financed ($157 million from intermediate-term notes and $150 million from bank credit arrangements). The intermediate-term notes mature in 1996 and 1997. The Company and Toledo Edison 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 $67 million, $57 million and $14 million, respectively, at December 31, 1994. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $7 million in 1994 and $9 million in both 1993 and 1992. The estimated future lease amortization payments based on projected consumption are $57 million in 1995, $52 million in 1996, $46 million in 1997, $43 million in 1998 and $36 million in 1999.

(7) Regulatory Matters

The Company is subject to the provisions of SFAS 71. Regulatory assets represent probable future revenues to the Company associated with certain incurred costs, which it will recover from customers through the ratemaking process. Regulatory assets in the Balance Sheet are as follows:

	December 31, 1994	December 31, 1993
	(millions of dollars)	
Amounts due from customers for future federal income taxes	$ 641	$ 586
Unamortized loss on reacquired debt	58	60
Pre-phase-in deferrals*	341	351
Rate Stabilization Program deferrals	237	168
Total	$1,277	$1,165

* 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, 1994, 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 17 to 34 years. We continually assess the effects of competition and the changing industry and regulatory environment on operations and the Company's ability to recover the regulatory assets. In the event that we determine that future revenues would not be provided for recovery of any regulatory asset, such asset would be required to be written off. See Management's Financial Analysis — Outlook-Regulatory Accounting.

The Company will file a request with the PUCO to restructure rates to increase revenues to be effective in 1996 which will include provision for recovery of the Rate Stabilization Program deferrals. We believe that rates will be set at a level consistent with cost-based regulations and will provide revenues to recover the then-current operating costs, return requirements and amortization of all regulatory assets listed above.

The Rate Stabilization Program that the PUCO approved in October 1992 was designed to encourage economic growth in the Company's service area by freezing the Company's base rates until 1996 and limiting subsequent

rate increases to specified annual amounts not to exceed $216 million over the 1996-1998 period.

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

The regulatory accounting measures we are eligible to record through December 31, 1995 include the deferral of post-in-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988. The cost deferrals recorded in 1994, 1993 and 1992 pursuant to these provisions were $66 million, $56 million and $52 million, respectively. The regulatory accounting measures also provide for the accelerated amortization of certain unrestricted excess deferred tax and unrestricted investment tax credit balances and interim spent fuel storage accrual balances for Davis-Besse. The total amount of such regulatory benefits recognized pursuant to these provisions was $28 million in both 1994 and 1993 and $7 million in 1992.

The Rate Stabilization Program also authorized the Company to defer and subsequently recover the incremental expenses associated with the adoption of the accounting standard for postretirement benefits other than pensions (SFAS 106). In 1994 and 1993, we deferred $4 million and $60 million, respectively, pursuant to this provision. Amortization and recovery of these deferrals are expected to commence in 1996 and to be completed by no later than 2012. See Note 9(b).

In 1993, upon completing a comprehensive study which led to our current 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. Such deferrals were scheduled to be recovered over the 1994 through 1998 period. The total phase-in deferred operating expenses and carrying charges written off at December 31, 1993 by the Company were $117 million and $519 million, respectively (totaling $433 million after taxes). See Note 14. Additionally, based on our assessment of business conditions, we concluded that, once the deferral of expenses and acceleration of benefits under our Rate Stabilization Program are completed in 1995, we should no longer plan to use regulatory accounting measures to the extent we have in the past.

(8) Federal Income Tax

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

	1994	1993	1992
	(millions of dollars)		
Operating Expenses:			
Current	$ 53	$ 64	$ 47
Deferred	29	(42)	42
Total Charged to Operating Expenses	82	22	89
Nonoperating Income:			
Current	(17)	(20)	(19)
Deferred	21	(250)	24
Total Expense (Credit) to Nonoperating Income	4	(270)	5
Total Federal Income Tax Expense (Credit)	$ 86	$(248)	$ 94

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 statutory rate (35% in 1994 and 1993 and 34% in 1992), is reconciled to the amount of federal income tax recorded on the books as follows:

	1994	1993	1992
	(millions of dollars)		
Book Income (Loss) Before Federal Income Tax	$271	$(835)	$299
Tax (Credit) on Book Income (Loss) at Statutory Rate	$ 95	$(292)	$102
Increase (Decrease) in Tax:			
Write-off of Perry Unit 2	—	30	—
Write-off of phase-in deferrals	—	20	—
Depreciation	6	6	(3)
Rate Stabilization Program	(18)	(20)	(5)
Other items	3	8	—
Total Federal Income Tax Expense (Credit)	$ 86	$(248)	$ 94

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 $187 million loss with a corresponding $65 million reduction in federal income tax liability. Because of the alternative minimum tax (AMT), $38 million of the $65 million was realized in 1994. The remaining $27 million will not be realized until 1999. Additionally, a repayment of approximately $32 million of previously allowed investment tax credits was recognized in 1994.

In August 1993, the Revenue Reconciliation Act of 1993 was enacted. Retroactive to January 1, 1993, the top marginal corporate income tax rate increased to 35%. The change in tax rate did not materially impact the results of operations for 1993, but increased Accumulated Deferred Federal Income Taxes for the future tax obligation by approximately $61 million. Since the PUCO has historically permitted recovery of such taxes from customers when they become payable, the deferred charge, Amounts Due from Customers for Future Federal Income Taxes, also was increased by $61 million.

Under SFAS 109, temporary differences and carryforwards resulted in deferred tax assets of $418 million and deferred tax liabilities of $1.652 billion at December 31, 1994 and deferred tax assets of $426 million and deferred tax liabilities of $1.531 billion at December 31, 1993. These are summarized as follows:

	December 31, 1994	December 31, 1993
	(millions of dollars)	
Property, plant and equipment	$1,429	$1,311
Deferred carrying charges and operating expenses	132	127
Net operating loss carryforwards	(88)	(69)
Investment tax credits	(105)	(128)
Sale and leaseback transactions	(125)	(126)
Other	(9)	(10)
Net deferred tax liability	$1,234	$1,105

For tax purposes, net operating loss (NOL) carryforwards of approximately $252 million are available to reduce future taxable income and will expire in 2003 through 2009. The 35% tax effect of the NOLs is $88 million. Additionally, AMT credits of $99 million that may be carried forward indefinitely are available to reduce future regular 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 and an additional $10 million of pension costs for VTP benefits paid to retirees from corporate funds. The $10 million is not included in the pension data reported in the following table. A credit of $81 million resulting from a settlement of pension obligations through lump sum payments to almost all the VTP retirees partially offset the VTP expenses.

Pension and VTP costs (credits) for Centerior Energy and its subsidiaries for 1992 through 1994 were comprised of the following components:

	1994	1993	1992
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 13	$ 15	$ 15
Interest cost on projected benefit obligation	26	37	38
Actual return on plan assets	(2)	(65)	(24)
Net amortization and deferral	(34)	4	(45)
Net pension costs (credits)	3	(9)	(16)
VTP cost	—	205	—
Settlement gain	—	(81)	—
Net costs (credits)	$ 3	$115	$(16)

Pension and VTP costs (credits) for the Company and its pro rata share of the Service Company's costs were $2 million, $62 million and $(16) million for 1994, 1993 and 1992, 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 50%.

	December 31, 1994	December 31, 1993
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$278	$333
Nonvested benefits	2	37
Accumulated benefit obligation	280	370
Effect of future compensation levels	37	53
Total projected benefit obligation	317	423
Plan assets at fair market value	362	386
Funded status	45	(37)
Unrecognized net loss (gain) from variance between assumptions and experience	(79)	11
Unrecognized prior service cost	10	10
Transition asset at January 1, 1987 being amortized over 19 years	(39)	(43)
Net accrued pension liability	$(63)	$(59)

A September 30, 1994 measurement date was used for 1994 reporting. At December 31, 1994, the settlement (discount) 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, 1993, the settlement rate and long-term rate of return on plan assets assumptions were 7.25% and 8.75%, respectively. The long-term rate of annual compensation increase assumption was 4.25%. At December 31, 1994 and 1993, the Company's net prepaid pension cost included in Deferred Charges and Other

Assets — Other in the Balance Sheet was $7 million and $9 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 ratemaking practices.

The components of the total postretirement benefit costs for 1994 and 1993 were as follows:

	1994	1993
	(millions of dollars)	
Service cost for benefits earned during the period	$ 1	$ 2
Interest cost on accumulated postretirement benefit obligation	11	10
Amortization of transition obligation at January 1, 1993 of $104 million over 20 years	5	5
VTP curtailment cost (includes $10 million transition obligation adjustment)	—	52
Total costs	$17	$69

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

In 1994 and 1993, the Company deferred incremental SFAS 106 expenses (in excess of the amounts paid) of $4 million and $60 million, respectively, pursuant to a provision of the Rate Stabilization Program. See Note 7.

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, 1994	December 31, 1993
	(millions of dollars)	
Accumulated postretirement benefit obligation attributable to:		
Retired participants	$(124)	$(141)
Fully eligible active plan participants	(1)	(1)
Other active plan participants	(14)	(19)
Accumulated postretirement benefit obligation	(139)	(161)
Unrecognized net loss (gain) from variance between assumptions and experience	(16)	9
Unamortized transition obligation	84	89
Accrued postretirement benefit cost	$ (71)	$ (63)

The Balance Sheet classification of Retirement Benefits at December 31, 1994 and 1993 includes only the Company's accrued postretirement benefit cost of $59 million and $52 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, 1994 measurement date was used for 1994 reporting. At December 31, 1994 and 1993, 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, 1994, the assumed annual health care cost trend rates (applicable to gross eligible charges) are 8.5% for medical and 8% for dental in 1995. 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, 1994 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 two coal suppliers under two long-term coal supply contracts. At December 31, 1994, the principal amount of the loan and lease obligations guaranteed by the Company under both contracts was $50 million. In addition, the Company may be responsible for mine closing costs when one of the contracts is terminated. At December 31, 1994, the unfunded costs of closing this mine as estimated by the supplier were $54 million.

The prices under both contracts which include certain minimum payments are sufficient to satisfy the loan and lease obligations and mine closing costs over the lives of the contracts. If either 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 sold and retired during the three years ended December 31, 1994 are listed in the following table.

	1994	1993	1992
	(thousands of shares)		
Subject to Mandatory Redemption:			
Sales			
$90.00 Series S	—	—	75
Retirements			
$ 7.35 Series C	(10)	(10)	(10)
88.00 Series E	(3)	(3)	(3)
Adjustable Series M	(100)	(100)	(100)
9.125 Series N	(189)	(150)	—
Not Subject to Mandatory Redemption:			
Sales			
$42.40 Series T	—	200	—
Retirements			
Remarketed Series P	—	—	(1)
Net (Decrease)	(302)	(63)	(39)

(b) Equity Distribution Restrictions

Federal law prohibits the Company from paying dividends out of capital accounts. However, the Company may pay preferred and common stock dividends out of appropriated retained earnings and current earnings. At December 31, 1994, the Company had $144 million of appropriated retained earnings for the payment of preferred and common stock dividends.

(c) Preferred and Preference Stock

Amounts to be paid for preferred stock which must be redeemed during the next five years are $36 million in 1995, $30 million in both 1996 and 1997, $15 million in 1998 and $33 million in 1999.

The annual preferred stock mandatory redemption provisions are as follows:

	Shares To Be Redeemed	Beginning in	Price Per Share
$ 7.35 Series C	10,000	1984	$ 100
88.00 Series E	3,000	1981	1,000
Adjustable Series M	100,000	1991	100
9.125 Series N	150,000	1993	100
91.50 Series Q	10,714	1995	1,000
88.00 Series R	50,000	2001*	1,000
90.00 Series S	18,750	1999	1,000

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

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

The annualized preferred dividend requirement at December 31, 1994 was $44 million.

The preferred dividend rates on the Company's Series L and M fluctuate based on prevailing interest rates and market conditions. The dividend rates for these issues averaged 7.17% and 7.01%, respectively, in 1994.

Preference stock authorized for the Company is 3,000,000 shares without 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, 1994	December 31, 1994	December 31, 1993
		(millions of dollars)	
First mortgage bonds:			
1996-1999	13.75%	$ 17	$ 21
1996-1999	7.00	3	4
1997-1999	10.88	18	18
1999	6.20	2	2
2000-2004	7.92	396	400
2005-2009	8.33	202	202
2010-2014	8.50	365	365
2015-2019	8.00	459	459
2020-2023	8.75	518	518
		1,980	1,989
Secured medium term notes due 1996-2021	8.68	516	713
Term bank loans due 1996	8.50	2	45
Pollution control notes due 1996-2012	6.82	52	53
Other — net	—	(7)	(7)
Total Long-Term Debt		$2,543	$2,793

Long-term debt matures during the next five years as follows: $246 million in 1995, $151 million in 1996, $55 million in 1997, $78 million in 1998 and $159 million in 1999.

The Company issued $125 million aggregate principal amount of secured medium-term notes in 1992 and 1993. The notes are secured by first mortgage bonds.

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 and supplies.

An unsecured loan agreement of the Company contains covenants relating to capitalization ratios, fixed charge coverage ratios and limitations on secured financing other than through first mortgage bonds or certain other transactions. Two reimbursement agreements relating to separate letters of credit issued in connection with the sale

and leaseback of Beaver Valley Unit 2 contain several financial covenants affecting the Company, Toledo Edison and Centerior Energy. Among these are covenants relating to fixed charge coverage ratios and capitalization ratios. The write-offs recorded at December 31, 1993 caused the Company, Toledo Edison and Centerior Energy to violate certain covenants contained in the loan agreement and the two reimbursement agreements. The affected creditors waived those violations in exchange for a subordinate mortgage security interest on the properties of the Company and Toledo Edison. The Company provided the same security interest to certain other creditors because their agreements require equal treatment. At December 31, 1994, the Company provided subordinate mortgage collateral for $45 million of unsecured debt, $228 million of bank letters of credit and a $205 million revolving credit facility. The bank letters of credit are joint and several obligations of the Company and Toledo Edison and the revolving credit facility is an obligation of Centerior Energy that is jointly and severally guaranteed by the Company and Toledo Edison.

(12) Short-Term Borrowing Arrangements

Centerior Energy has a $205 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 Toledo Edison. Centerior Energy plans to transfer any of its borrowed funds to the Company and Toledo Edison. The facility agreement as amended provides the participating banks with a subordinate mortgage security interest on the properties of the Company and Toledo Edison. 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, 1994. The facility agreement contains covenants relating to capitalization and fixed charge coverage ratios for the Company, Toledo Edison and Centerior Energy.

Short-term borrowing capacity authorized by the PUCO annually is $300 million for the Company. The Company and Toledo Edison are authorized by the PUCO to borrow from each other on a short-term basis. At December 31, 1994, the Company had total short-term borrowings of $58 million from its affiliates with a weighted average interest rate of 6.14%.

(13) Financial Instruments

Except for the Nuclear Plant Decommissioning Trusts at December 31 1994, as discussed below, the estimated fair values at December 31, 1994 and 1993 of financial instruments that do not approximate their carrying amounts in the Balance Sheet are as follows:

	December 31, 1994 Carrying Amount	1994 Fair Value	1993 Carrying Amount	1993 Fair Value
	(millions of dollars)			
Assets:				
Nuclear Plant Decommissioning Trusts	$ 44	$ 44	$ 30	$ 32
Capitalization and Liabilities:				
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	282	245	314	307
Long-Term Debt (including current portion)	2,795	2,503	2,841	2,946

The Nuclear Plant Decommissioning Trusts at December 31, 1994 included $25 million of federal governmental securities and $17 million of municipal securities. The securities had the following maturities: $11 million due within one year; $8 million due in one to five years; $10 million due in six to 10 years; and $13 million due after 10 years. 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 is equal to the 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, 1994 and 1993 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, 1994.

	Quarters Ended March 31,	June 30,	Sept. 30,	Dec. 31,
	(millions of dollars)			
1994				
Operating Revenues	$408	$415	$474	$ 401
Operating Income	86	91	132	88
Net Income	33	38	79	35
Earnings Available for Common Stock	21	27	68	24
1993				
Operating Revenues	$421	$417	$507	$ 406
Operating Income (Loss)	82	85	89	(32)
Net Income (Loss)	33	30	39	(689)
Earnings (Loss) Available for Common Stock	23	19	27	(701)

Earnings for the quarter ended September 30, 1993 were decreased by $46 million as a result of the recording of $71 million of VTP pension-related benefits.

Earnings for the quarter ended December 31, 1993 were decreased as a result of year-end adjustments for the $351 million write-off of Perry Unit 2 (see Note 4(b)), the $636 million write-off of the phase-in deferrals (see Note 7) and $38 million of other charges. These adjustments decreased quarterly earnings by $716 million.

(15) Pending Merger of Toledo Edison into the Company

In March 1994, Centerior Energy announced a plan to merge Toledo Edison into the Company. Since the Company and Toledo Edison 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 PUCO and the Pennsylvania Public Utility Commission have approved the merger. In addition, the merger must be approved by share owners of Toledo Edison's preferred stock. Share owners of the Company's preferred stock must approve the authorization of additional shares of preferred stock. When the merger becomes effective, share owners of Toledo Edison's preferred stock will exchange their shares for preferred stock shares of the Company having substantially the same terms. Debt holders of the merging companies will become debt holders of the Company. The merging companies plan to seek preferred stock share owner approval in mid-1995. The merger is expected to be effective in 1995.

For the merging companies, the combined pro forma operating revenues were $2.422 billion, $2.475 billion and $2.439 billion and the combined pro forma net income (loss) was $268 million, $(876) million and $276 million for the years 1994, 1993 and 1992, 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 Toledo Edison.

Financial and Statistical Review

Operating Revenues (millions of dollars)

Year	Residential	Commercial	Industrial	Other	Total Retail	Wholesale	Total Electric	Steam Heating	Total Operating Revenues
1994	$531	541	508	98	1 678	20	1 698	—	$1 698
1993	539	536	510	98	1 683	68	1 751	—	1 751
1992	517	531	530	101	1 679	64	1 743	—	1 743
1991	547	540	547	117	1 751	75	1 826	—	1 826
1990	495	494	544	123	1 656	35	1 691	—	1 691
1984	376	339	441	44	1 200	6	1 206	15	1 221

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	Total Operating Expenses
1994	$391	394	56	195	218	(34)	82	$1 302
1993	423	598 *(a)*	56	182	221	27 *(b)*	22	1 529
1992	434	410	55	179	226	(35)	89	1 358
1991	455	414	56	171 *(c)*	216	(7)	106	1 411
1990	412	460	54	170	197	(24)	75	1 344
1984	319	281	—	95	132	—	131	958

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
1994	$396	4	6	25	(4)	$ 427
1993	222	4	(356) *(d)*	(487) *(b)*	270	(347)
1992	385	1	8	59	(5)	448
1991	415	8	6	88	(24)	493
1990	347	5	1	162	(20)	495
1984	263	130	3	—	35	431

Income (Loss) (millions of dollars)

Year	Debt Interest	AFUDC—Debt	Net Income (Loss)	Preferred & Preference Stock Dividends	Earnings (Loss) Available for Common Stock
1994	$247	(5)	185	45	$ 140
1993	244	(4)	(587)	45	(632)
1992	243	—	205	41	164
1991	251	(4)	246	36	210
1990	255	(3)	243	37	206
1984	181	(41)	291	43	248

(a) Includes early retirement program expenses and other charges of $165 million in 1993.

(b) Includes write-off of phase-in deferrals of $636 million in 1993, consisting of $117 million of deferred operating expenses and $519 million of deferred carrying charges.

(c) In 1991, 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.

	Electric Sales (millions of KWH)						**Electric Customers** (year end)				**Residential Usage**		
Year	Residential	Commercial	Industrial	Wholesale	Other	Total	Residential	Commercial	Industrial & Other	Total	Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
1994	4 924	5 770	7 970	1 073	575	20 312	668 346	71 609	7 401	747 356	7 370	10.79¢	$795.11
1993	4 934	5 634	7 911	2 290	532	21 301	669 118	70 442	8 149	747 709	7 373	10.93	805.68
1992	4 725	5 467	7 988	1 989	533	20 702	669 800	70 943	8 375	749 118	7 071	10.94	773.77
1991	4 940	5 493	8 017	2 442	565	21 457	667 495	70 405	8 398	746 298	7 170	11.08	797.25
1990	4 716	5 234	8 551	1 607	463	20 571	665 000	68 700	8 351	742 051	6 867	10.53	723.15
1984	4 446	4 396	7 997	142	431	17 412	644 904	61 934	7 930	714 768	6 646	8.48	563.60

	Load (MW & %)				**Energy** (millions of KWH)					**Fuel**	
					Company Generated						
Year	Net Seasonal Capability	Peak Load	Capacity Margin	Load Factor	Fossil	Nuclear	Total	Purchased Power	Total	Fuel Cost Per KWH	Efficiency—BTU Per KWH
1994	4 497	3 740	16.8%	62.4%	12 986	6 405	19 391	2 022	21 413	1.35¢	10 538
1993	4 497	3 862	14.1	59.9	15 557	5 644	21 201	1 454	22 655	1.37	10 339
1992	4 701	3 605	23.3	63.0	12 715	7 521	20 236	1 649	21 885	1.47	10 456
1991	4 701	3 886	17.3	61.8	13 193	7 451	20 644	2 144	22 788	1.49	10 503
1990	4 686	3 778	19.4	63.3	15 579	5 262	20 841	964	21 805	1.52	10 417
1984	3 696	3 371	8.8	64.5	14 749	2 212	16 961	1 770	18 731	1.70	10 416

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
1994	$6 871	2 014	4 857	99	195	$5 151	$156	$7 151
1993	6 734	1 889	4 845	141	243	5 229	175	7 159
1992	6 602	1 728	4 874	501	261	5 636	156	8 123
1991	6 196	1 565	4 631	545	305	5 481	150	7 942
1990	6 032	1 398	4 634	572	344	5 550	165	7 821
1984	2 909	799	2 110	2 114	289*(e)*	4 513	582	5 120

Capitalization (millions of dollars & %)

Year	Common Stock Equity		Preferred & Preference Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
1994	$1 058	26%	246	6%	241	6%	2 543	62%	$4 088
1993	1 040	24	285	7	241	5	2 793	64	4 359
1992	1 865	39	314	6	144	3	2 515	52	4 838
1991	1 898	38	268	5	217	4	2 683	53	5 066
1990	1 884	38	171	3	217	4	2 632	55	4 904
1984	1 593	41	293	7	144	4	1 884	48	3 914

(d) Includes write-off of Perry Unit 2 of $351 million in 1993.

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

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, 1994 and 1993, and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1994. These financial statements and the schedule referred to below are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Toledo Edison Company as of December 31, 1994 and 1993, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1994, 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.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule of The Toledo Edison Company listed in the Index to Schedules is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Cleveland, Ohio
February 17, 1995

Management's Financial Analysis

Outlook

Strategic Plan

We made significant strides in achieving the objectives of the comprehensive strategic action plan announced in January 1994. Centerior Energy Corporation (Centerior Energy), along with The Toledo Edison Company (Company) and The Cleveland Electric Illuminating Company (Cleveland Electric), created the strategic plan to strengthen their financial and competitive position through the year 2001. 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 an industry 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. To achieve these objectives, we will continue to control expenditures and reduce our outstanding debt and preferred stock. In addition, we will increase revenues by finding new uses for existing assets and resources, implementing new marketing programs and restructuring rates when appropriate. We will also improve the operating performance of our generating plants and take other appropriate actions.

During 1994, we made progress toward most of our long-term objectives. The Company and Cleveland Electric initiated a marketing plan designed to increase total retail revenues (exclusive of fuel cost recovery revenues and weather influences) by 2-3% annually through 2001. Our new customer service activities are intended to raise our customer satisfaction rating. Our employees achieved enough of their established objectives for the year to receive a $500 per eligible employee incentive compensation award. The work undertaken during refueling outages at the Davis-Besse Nuclear Power Station (Davis-Besse) and Perry Nuclear Power Plant Unit 1 (Perry Unit 1) as well as the outage work at our fossil-fueled plants should help us achieve our long-term objective of reducing variable power costs to a more competitive level. Strong cash flow continued in 1994 and the Company's fixed-income obligations were reduced by $66 million. Also, the Company's total operation and maintenance expenses declined $22 million, exclusive of one-time charges in 1993.

We are taking aggressive steps to increase revenues through our enhanced marketing plan and to control costs. The full impact of these efforts will take time. In the meantime, the Company and Cleveland Electric must raise revenues by restructuring rates. Accordingly, the Company and Cleveland Electric are preparing to file a request with The Public Utilities Commission of Ohio (PUCO) to be effective in 1996. Meaningful cost control and marketing strategies will mitigate the need for additional rate increases and help us meet competition.

Competition

We are implementing strategies designed to create and enhance our competitive advantages and to overcome the competitive disadvantages that we face due to regulatory and tax constraints and our high retail cost structure.

Currently our most pressing competition comes from municipal electric systems in our service area. Our rates are generally higher than those of municipal systems due largely to their exemption from taxation, the lower cost financing available to them, the continued availability to them of lower cost power through short-term power purchases and their access to cheaper governmental power. We are seeking to address the tax disparity through the legislative process. In 1994, the Ohio Governor's Tax Commission recommended the replacement of the gross receipts and personal property taxes currently levied only on investor-owned utilities and collected through rates with a different tax collected from customers of all electric utilities, including municipal systems. Investor-owned utilities would reduce rates upon repeal of the existing taxes. We are now working to submit this proposal to the Ohio legislature.

We face the threat that municipalities in our service area could establish new systems and continue expanding existing systems. We are responding with aggressive marketing programs and by emphasizing the value of our service and the risks of a municipal system: substantial, long-term debt; no guarantee of low-cost wholesale electricity; the difficulty of forecasting costs; and the uncertainty of market share as a result of our aggressive competition. Generally, these municipalities have determined that developing a system is not feasible or have agreed with us not to pursue development of a system at this time. Although some communities continue to be interested in municipalization, we believe that we offer the best value and most reliable source of electric service in our territory.

The Energy Policy Act of 1992 will increase competition in the electric utility industry by allowing broader access to a utility's transmission system. It should not significantly increase the competitive threat to us since we have been required to wheel electricity to municipal systems in our service area since 1977 under operating licenses for our nuclear generating units. Further, the government could eventually require utilities to deliver power from other utilities or generation sources to their retail customers. To combat this threat, we are offering incentives such as energy-efficiency improvements and reductions in demand charges for increased electricity usage to our industrial and commercial customers in return for long-term commitments. Most of our large industrial and

commercial customers have entered into sole-supplier contracts with us. More than 80% of our industrial revenues under contract will not be up for renewal until 1997 or later. As these contracts expire, we expect to renegotiate them and retain the customers.

Rate Matters

Under the Rate Stabilization Program discussed in Note 7, we agreed to freeze base rates until 1996 and limit rate increases through 1998. In exchange, we are permitted to defer through 1995 and subsequently recover certain costs not currently recovered in rates and to accelerate the amortization of certain benefits. Amortization and recovery of the deferrals are expected to begin in 1996 with future rate recognition and will continue over the average life of the related assets, or between 17 and 30 years. The continued use of these regulatory accounting measures in 1995 will be dependent upon our continuing assessment and conclusion that there will be probable recovery of such deferrals in future rates. Our analysis leading to certain year-end 1993 financial actions and the strategic plan also included an evaluation of our regulatory accounting measures. See Regulatory Accounting below and Note 7. We decided that, once the deferral of expenses and acceleration of benefits under the Rate Stabilization Program are completed in 1995, we should no longer plan to use these measures to the extent we have in the past.

Regulatory Accounting

As described in Notes 1(a) and 7, the Company complies with the provisions of Statement of Financial Accounting Standards (SFAS) 71. We continually 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 establish rates to recover operating costs, return requirements and the amortization of regulatory assets and (2) a significant change in the manner in which rates are set by the PUCO from cost-based regulations to some other form of regulations. In the event we determine that the Company no longer meets the criteria for following SFAS 71, the Company would be required to record a before-tax charge to write off the regulatory assets shown in Note 7. 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 would also result in an impairment of the net book value of the Company's property, plant and equipment.

The Company's write-off in 1993 of the phase-in deferred operating expenses and carrying charges (phase-in deferrals) discussed in Note 7 resulted from our conclusion that projected revenues for the 1994-1998 period would not provide for recovery of such deferrals as scheduled by the PUCO order. This short time frame for recovery of the phase-in deferrals is a requirement under the accounting standard for phase-in plans of regulated enterprises, SFAS 92. The remaining recovery periods for all remaining regulatory assets are between 17 and 34 years. We believe the Company's rates will provide for recovery of these assets over the relevant periods and SFAS 71 continues to apply.

Nuclear Operations

The Company has interests in three nuclear generating units — Davis-Besse, 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 have been operating extremely well, with each unit having a three-year availability average at year-end 1994 that exceeded the three-year industry average of 80% for similar reactors. However, the three-year availability average of Perry Unit 1 was below the three-year industry availability average for that reactor type.

In 1994, Davis-Besse had an availability factor of 88%. Further, Davis-Besse completed the shortest refueling and maintenance outage in its history in 1994, returning to service just 46 days after shutting down. Cleveland Electric is in the process of upgrading Perry Unit 1 to the same level. For seven months in 1994, Perry Unit 1 was out of service for its fourth refueling and maintenance outage. Work was also performed in connection with the comprehensive course of action developed in 1993 to improve the operating performance of Perry Unit 1. Work in connection with that course of action is ongoing.

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 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.

Hazardous Waste Disposal Sites

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended (Superfund) established programs addressing the cleanup of hazardous waste disposal sites, emergency preparedness and other issues. The 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 amounts involved, are often unsubstantiated and subject to dispute. Superfund provides that all "potentially responsible parties" (PRPs) for a particular site can 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, 1994 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 Company and Cleveland Electric plan to seek preferred stock share owner approval in mid-1995. The merger is expected to be effective in 1995. See Note 15.

Inflation

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

Capital Resources and Liquidity

1992-1994 Cash Requirements

We need cash for normal corporate operations, the mandatory retirement of securities and constructing and modifying facilities. Construction is needed to meet anticipated demand for electric service, comply with government regulations and protect the environment. Over the three-year period 1992-1994, construction and mandatory retirement needs totaled approximately $370 million. In addition, we exercised options to redeem approximately $460 million of our securities.

We raised $603 million through security issues and term bank loans during the 1992-1994 period. The Company also utilized short-term borrowings to help meet its cash needs. Although write-offs of the Company's Perry Nuclear Power Plant Unit 2 (Perry Unit 2) investment and phase-in deferrals in 1993 negatively affected earnings, they did not adversely affect cash flow. See Notes 4(b) and 7.

1995 and Beyond Cash Requirements

Estimated cash requirements for 1995-1999 for the Company are $288 million for construction and $378 million for the mandatory redemption of debt and preferred stock. The Company expects to meet nearly all of its 1995 and 1996 cash requirements of approximately $145 million and $154 million, respectively, through internal cash generation and current cash resources. The Company expects to meet nearly all of its 1997-1999 requirements through internal cash generation and current cash resources. If economical, additional securities may be redeemed under optional redemption provisions. We expect that the Company's continued strong cash flow will reduce borrowing requirements and outstanding debt and preferred stock during this period.

Cash expenditures to comply with the Clean Air Act Amendments of 1990 (Clean Air Act) are estimated to be approximately $22 million over the 1995-1999 period. See Note 4(a).

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, 1994, the Company would have been permitted to issue approximately $525 million of additional first mortgage bonds.

The Company also is able to raise funds through the sale of subordinated 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, 1994, the Company would have been permitted to issue approximately $28 million of additional preferred stock at an assumed dividend rate of 12%. There are no restrictions on the Company's ability to issue preference stock.

In 1995, the Company plans to raise funds through the collateralization of accounts receivable. In addition, the Company expects to issue first mortgage bonds as collateral security for the sale by a public authority of tax-exempt bonds.

The Company is a party to a $205 million revolving credit facility which runs through mid-1996. See Note 12. The Company had $88 million of cash and temporary cash investments at the end of 1994. The Company is unable to issue commercial paper because of its below investment grade commercial paper ratings.

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
Unsecured notes	B+	B1
Preferred stock	B	b2

Results of Operations

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 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.

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). Two other significant reasons for lower operation and maintenance expenses in 1994 were a smaller work force and ongoing cost reduction measures. 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. 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, 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.

1993 vs. 1992

Factors contributing to the 3.1% increase in 1993 operating revenues are as follows:

Increase (Decrease) in Operating Revenues	Millions of Dollars
KWH Sales Volume and Mix	$ 38
Wholesale Sales	(11)
Base Rates and Miscellaneous	(3)
Fuel Cost Recovery Revenues	2
Total	$ 26

The revenue increase resulted primarily from the different weather conditions and the changes in the composition of the sales mix among customer categories. Weather accounted for approximately $15 million of higher 1993 base rate revenues. Hot summer weather in 1993 boosted residential and commercial kilowatt-hour sales. In contrast, the 1992 summer was the coolest in 56 years for Northwestern Ohio. Residential and commercial sales also increased as a result of colder late-winter temperatures in 1993 which increased electric heating-related demand. Residential and commercial sales increased 5.1% and 3.2%, respectively, in 1993. Industrial sales increased 6% as a result of increased sales to large automotive manufacturers, petroleum refiners and the broad-based, smaller industrial customer group. Other sales decreased 18% because of fewer sales to wholesale customers. Generating plant outages and retail customer demand limited power availability for bulk power transactions. As a result, total sales decreased 2.2% in 1993. Base rates and miscellaneous revenues decreased in 1993 primarily from lower revenues under contracts having reduced rates with certain large customers and a declining rate structure tied to usage. The contracts have been negotiated to meet competition and encourage economic growth. The increase in 1993 fuel cost recovery revenues resulted from changes in the fuel cost factors. The weighted average of these factors increased about 2%.

For 1993, operating revenues were 26% residential, 21% commercial, 28% industrial and 25% other and kilowatt-hour sales were 20% residential, 17% commercial, 37% industrial and 26% other. The average prices per kilowatt-hour for residential, commercial and industrial customers were $.11, $.11 and $.06, respectively. The changes from 1992 were not significant.

Operating expenses increased 13% in 1993. The increase in total operation and maintenance expenses resulted from the $88 million of net benefit expenses related to the VTP, other charges totaling $19 million and a slight increase in other operation and maintenance expenses. Deferred operating expenses decreased because of the write-off of the phase-in deferred operating expenses in 1993. Federal income taxes decreased as a result of lower pretax operating income.

As mentioned above, $232 million of our Perry Unit 2 investment was written off in 1993. Credits for carrying charges recorded in nonoperating income decreased because of the write-off of the phase-in deferred carrying charges in 1993. The federal income tax credit for nonoperating income in 1993 resulted from the write-offs.

Income Statement

The Toledo Edison Company

	For the years ended December 31,		
	1994	1993 (millions of dollars)	1992
Operating Revenues (1)	$865	$ 871	$845
Operating Expenses			
Fuel and purchased power	167	173	169
Other operation and maintenance	229	245	236
Generation facilities rental expense, net	104	104	106
Early retirement program expenses and other	—	107	—
Total operation and maintenance	500	629	511
Depreciation and amortization	83	76	77
Taxes, other than federal income taxes	90	91	91
Deferred operating expenses, net	(21)	(4)	(17)
Federal income taxes (credit)	33	(10)	33
	685	782	695
Operating Income	180	89	150
Nonoperating Income (Loss)			
Allowance for equity funds used during construction	1	1	1
Other income and deductions, net	3	—	1
Write-off of Perry Unit 2	—	(232)	—
Deferred carrying charges, net	15	(161)	41
Federal income taxes — credit (expense)	(2)	129	(1)
	17	(263)	42
Income (Loss) Before Interest Charges	197	(174)	192
Interest Charges			
Debt interest	116	116	122
Allowance for borrowed funds used during construction	(1)	(1)	(1)
	115	115	121
Net Income (Loss)	82	(289)	71
Preferred Dividend Requirements	20	23	24
Earnings (Loss) Available for Common Stock	$ 62	$(312)	$ 47

(1) Includes revenues from all bulk power sales to Cleveland Electric of $111 million, $120 million and $130 million in 1994, 1993 and 1992, respectively.

Retained Earnings

	For the years ended December 31,		
	1994	1993 (millions of dollars)	1992
Retained Earnings (Deficit) at Beginning of Year	$(175)	$ 137	$ 90
Additions			
Net income (loss)	82	(289)	71
Deductions			
Preferred stock dividends declared	(20)	(23)	(24)
Net Increase (Decrease)	62	(312)	47
Retained Earnings (Deficit) at End of Year	$(113)	$(175)	$137

The accompanying notes are an integral part of these statements.

Balance Sheet

	December 31, 1994	December 31, 1993
	(millions of dollars)	
ASSETS		
Property, Plant and Equipment		
Utility plant in service	$2,899	$2,837
Less: accumulated depreciation and amortization	892	788
	2,007	2,049
Construction work in progress	30	40
	2,037	2,089
Nuclear fuel, net of amortization	119	142
Other property, less accumulated depreciation	6	—
	2,162	2,231
Current Assets		
Cash and temporary cash investments	88	82
Amounts due from customers and others, net	62	63
Amounts due from affiliates	19	16
Unbilled revenues	22	25
Materials and supplies, at average cost	45	43
Fossil fuel inventory, at average cost	12	12
Taxes applicable to succeeding years	72	71
Other	2	2
	322	314
Deferred Charges and Other Assets		
Amounts due from customers for future federal income taxes	405	382
Unamortized loss from Beaver Valley Unit 2 sale	101	105
Unamortized loss on reacquired debt	28	32
Carrying charges and operating expenses	379	343
Nuclear plant decommissioning trusts	38	26
Other	67	77
	1,018	965
Total Assets	$3,502	$3,510

The accompanying notes are an integral part of this statement.

	December 31, 1994	December 31, 1993
	(millions of dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shares, $5 par value: 60 million authorized; 39.1 million outstanding in 1994 and 1993	$ 196	$ 196
Premium on capital stock	481	481
Other paid-in capital	121	121
Retained earnings (deficit)	(113)	(175)
Common stock equity	685	623
Preferred stock		
With mandatory redemption provisions	7	28
Without mandatory redemption provisions	210	210
Long-term debt	1,154	1,225
	2,056	2,086
Current Liabilities		
Current portion of long-term debt and preferred stock	83	57
Current portion of nuclear fuel lease obligations	36	49
Accounts payable	48	63
Accounts payable to affiliates	31	27
Accrued taxes	75	90
Accrued interest	27	27
Other	16	16
	316	329
Deferred Credits and Other Liabilities		
Unamortized investment tax credits	87	94
Accumulated deferred federal income taxes	541	471
Unamortized gain from Bruce Mansfield Plant sale	198	208
Accumulated deferred rents for Bruce Mansfield Plant and Beaver Valley Unit 2	54	50
Nuclear fuel lease obligations	87	103
Retirement benefits	103	98
Other	60	71
	1,130	1,095
Total Capitalization and Liabilities	$3,502	$3,510

Cash Flows

The Toledo Edison Company

	1994	1993	1992
	For the years ended December 31,		
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income (Loss)	$ 82	$(289)	$ 71
Adjustments to Reconcile Net Income (Loss) to Cash from Operating Activities:			
Depreciation and amortization	83	76	77
Deferred federal income taxes	46	(160)	28
Investment tax credits, net	—	—	(5)
Unbilled revenues	3	(4)	1
Deferred fuel	3	—	(4)
Deferred carrying charges, net	(15)	161	(41)
Leased nuclear fuel amortization	44	38	56
Deferred operating expenses, net	(21)	(4)	(17)
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	1	(3)	—
Changes in inventories	(2)	10	(9)
Changes in accounts payable	(15)	16	(8)
Changes in working capital affecting operations	(16)	21	7
Other noncash items	10	14	13
Total Adjustments	120	479	97
Net Cash from Operating Activities	202	190	168
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	—	(40)	40
Notes payable to affiliates	—	—	(30)
First mortgage bond issues	31	20	276
Secured medium-term note issues	—	93	48
Debenture issue	—	—	135
Maturities, redemptions and sinking funds	(98)	(89)	(531)
Nuclear fuel lease obligations	(49)	(47)	(52)
Dividends paid	(20)	(23)	(24)
Premiums, discounts and expenses	—	(1)	(8)
Net Cash from Financing Activities	(136)	(87)	(146)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(41)	(42)	(48)
Interest capitalized as allowance for borrowed funds used during construction	(1)	(1)	(1)
Loans to affiliates	—	—	12
Sale and leaseback restructuring fees	—	—	(43)
Contributions to nuclear plant decommissioning trusts	(12)	(4)	(4)
Other cash received (applied)	(6)	10	(1)
Net Cash from Investing Activities	(60)	(37)	(85)
Net Change in Cash and Temporary Cash Investments	6	66	(63)
Cash and Temporary Cash Investments at Beginning of Year	82	16	79
Cash and Temporary Cash Investments at End of Year	$ 88	$ 82	$ 16

(1) Interest paid (net of amounts capitalized) was $94 million, $92 million and $95 million in 1994, 1993 and 1992, respectively. Income taxes paid were $5 million, $7 million and $3 million in 1994, 1993 and 1992, respectively.

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

The accompanying notes are an integral part of this statement.

Statement of Preferred Stock

	1994 Shares Outstanding	Current Call Price Per Share	December 31, 1994	December 31, 1993
			(millions of dollars)	
$100 par value, 3,000,000 preferred shares authorized and $25 par value, 12,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$100 par $9.375	83,500	$101.98	$ 8	$ 10
25 par 2.81	400,000	25.62	10	30
			18	40
Less: Current maturities			11	12
Total Preferred Stock, with Mandatory Redemption Provisions			$ 7	$ 28
Not subject to mandatory redemption:				
$100 par $ 4.25	160,000	104.625	$ 16	$ 16
4.56	50,000	101.00	5	5
4.25	100,000	102.00	10	10
8.32	100,000	102.46	10	10
7.76	150,000	102.437	15	15
7.80	150,000	101.65	15	15
10.00	190,000	101.00	19	19
25 par 2.21	1,000,000	25.25	25	25
2.365	1,400,000	27.75	35	35
Series A Adjustable	1,200,000	25.75	30	30
Series B Adjustable	1,200,000	25.75	30	30
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 Federal Energy Regulatory Commission (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 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 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 $59 million, $71 million and $60 million in 1994, 1993 and 1992, 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 Amortization

The cost of property, plant and equipment is depreciated over their estimated useful lives on a straight-line basis. The annual straight-line depreciation provision for non-nuclear property expressed as a percent of average depreciable utility plant in service was 3.5% in 1994 and 3.6% in both 1993 and 1992. The annual straight-line depreciation rate for nuclear property is 2.5%.

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 allowing net earnings to 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 $4 million level in 1992. The accruals are reflected in current rates. The increased accruals were derived from recently 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 amounts 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, 1994 includes $44 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 is reviewing the accounting for removal costs, including decommissioning. If such 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.

(f) Property, Plant and Equipment

Property, plant and equipment are stated at original cost less amounts ordered by the PUCO to be written off. Construction costs include related payroll taxes, 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 9.87% in 1994, 10.22% in 1993 and 10.96% in 1992.

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 leases. See Note 7. 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. Such losses and gains are either amortized over the remainder of the original life of the debt issue retired or amortized over the life of the new debt issue when the proceeds of a new issue are used for the debt redemption. The amortizations are included in debt interest expense.

(i) Federal Income Taxes

The 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.

Investment tax credits are deferred and amortized over the lives of the applicable property as a reduction of

depreciation expense. See Note 7 for a discussion of the amortization of certain unrestricted excess deferred taxes and unrestricted investment tax credits under the Rate Stabilization Program.

(2) Utility Plant Sale and Leaseback Transactions

The 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, all for terms of about 29½ years. These leases 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. Additional lease provisions provide other purchase options along with conditions for mandatory termination of the leases (and possible repurchase of the leasehold interests) for events of default. These events include noncompliance with any of several financial covenants discussed in Note 11(d).

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.

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

Future minimum lease payments under the operating leases at December 31, 1994 are summarized as follows:

Year	For the Company	For Cleveland Electric
	(millions of dollars)	
1995	$ 103	$ 63
1996	125	63
1997	102	63
1998	102	63
1999	108	70
Later Years	1,918	1,321
Total Future Minimum Lease Payments	$2,458	$1,643

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1994, 1993 and 1992 as annual rental expense for the Mansfield Plant leases was $45 million. The amounts recorded in 1994, 1993 and 1992 as annual rental expense for the Beaver Valley Unit 2 lease were $64 million, $63 million and $66 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 $108 million, $103 million and $108 million in 1994, 1993 and 1992, respectively. We anticipate that this sale will continue indefinitely. The future minimum lease payments through the year 2017 associated with Beaver Valley Unit 2 aggregate $1.413 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, 1994 includes the following facilities owned by the Company as a tenant in common with other utilities and Lessors:

Generating Unit	In-Service Date	Ownership Share	Ownership Megawatts	Power Source	Plant in Service	Construction Work in Progress	Accumulated Depreciation
					(millions of dollars)		
Davis-Besse	1977	48.62%	429	Nuclear	$ 642	$ 4	$179
Perry Unit 1	1987	19.91	238	Nuclear	1,043	4	197
Beaver Valley Unit 2 and Common Facilities (Note 2)	1987	1.65	13	Nuclear	204	3	42
Total					$1,889	$11	$418

(4) Construction and Contingencies

(a) Construction Program

The estimated cost of the Company's construction program for the 1995-1999 period is $303 million, including AFUDC of $15 million and excluding nuclear fuel.

The 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 1994 in connection with Clean Air Act compliance amounted to $1 million. The plan will require additional capital expenditures over the 1995-2004 period of approximately $32 million for nitrogen oxide control equipment and plant modifications. In addition, higher fuel and other operation and maintenance expenses may be incurred. The anticipated rate increase associated with the capital expenditures and higher expenses would be less than 2% over the ten-year period.

(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. See Note 14.

(c) Hazardous Waste Disposal Sites

The Company is aware of its potential involvement in the cleanup of several hazardous waste disposal sites. The Company has accrued a liability totaling $5 million at December 31, 1994 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 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 (plus any inflation adjustment) 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, 1995. 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. Under these policies, the Company can be assessed a maximum of $10 million during a policy year if the reserves available to the insurer are inadequate to pay claims arising out of an accident at any nuclear facility covered by the insurer.

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. At December 31, 1994, $307 million ($125 million for the Company and $182 million for Cleveland Electric) of nuclear fuel was financed ($157 million from intermediate-term notes and $150 million from bank credit arrangements). The intermediate-term notes mature in 1996 and 1997. 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 $61 million, $34 million and $10 million, respectively, at December 31, 1994. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $4 million in 1994 and $6 million in both 1993 and 1992. The estimated future lease amortization payments based on projected consumption are $43 million in 1995, $38 million in 1996, $34 million in 1997, $31 million in 1998 and $27 million in 1999.

(7) Regulatory Matters

The Company is subject to the provisions of SFAS 71. Regulatory assets represent probable future revenues to the Company associated with certain incurred costs, which it will recover from customers through the ratemaking process. Regulatory assets in the Balance Sheet are as follows:

	December 31, 1994	December 31, 1993
	(millions of dollars)	
Amounts due from customers for future federal income taxes	$405	$382
Unamortized loss from Beaver Valley Unit 2 sale	101	105
Unamortized loss on reacquired debt	28	32
Pre-phase-in deferrals*	229	236
Rate Stabilization Program deferrals	150	107
Total	$913	$862

* 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, 1994, 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 17 to 34 years. We continually assess the effects of competition and the changing industry and regulatory environment on operations and the Company's ability to recover the regulatory assets. In the event that we determine that future revenues would not be provided for recovery of any regulatory asset, such asset would be required to be written off. See Management's Financial Analysis — Outlook-Regulatory Accounting.

The Company will file a request with the PUCO to restructure rates to increase revenues to be effective in 1996 which will include provision for recovery of the Rate Stabilization Program deferrals. We believe that rates will be set at a level consistent with cost-based regulations and will provide revenues to recover the then-current operating costs, return requirements and amortization of all regulatory assets listed above.

The Rate Stabilization Program that the PUCO approved in October 1992 was designed to encourage economic growth in the Company's service area by freezing the Company's base rates until 1996 and limiting subsequent rate increases to specified annual amounts not to exceed $89 million over the 1996-1998 period.

As part of the Rate Stabilization Program, during the 1992-1995 period the Company is allowed to defer and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. The continued use of these regulatory accounting measures will be dependent upon our continuing assess-

ment and conclusion that there will be probable recovery of such deferrals in future rates.

The regulatory accounting measures we are eligible to record through December 31, 1995 include the deferral of post-in-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988 and the deferral of operating expenses equivalent to an accumulated excess rent reserve for Beaver Valley Unit 2 (which resulted from the April 1992 refinancing of SLOBs as discussed in Note 2). The cost deferrals recorded in 1994, 1993 and 1992 pursuant to these provisions were $40 million, $39 million and $32 million, respectively. The regulatory accounting measures also provide for the accelerated amortization of certain unrestricted excess deferred tax and unrestricted investment tax credit balances and interim spent fuel storage accrual balances for Davis-Besse. The total amount of such regulatory benefits recognized pursuant to these provisions was $18 million in both 1994 and 1993 and $5 million in 1992.

The Rate Stabilization Program also authorized the Company to defer and subsequently recover the incremental expenses associated with the adoption of the accounting standard for postretirement benefits other than pensions (SFAS 106). In 1994 and 1993 we deferred $2 million and $37 million, respectively, pursuant to this provision. Amortization and recovery of these deferrals are expected to commence in 1996 and to be completed by no later than 2012. See Note 9(b).

In 1993, upon completing a comprehensive study which led to our current 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. Such deferrals were scheduled to be recovered over the 1994 through 1998 period. 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). See Note 14. Additionally, based on our assessment of business conditions, we concluded that, once the deferral of expenses and acceleration of benefits under our Rate Stabilization Program are completed in 1995, we should no longer plan to use regulatory accounting measures to the extent we have in the past.

(8) Federal Income Tax

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

	1994	1993	1992
	(millions of dollars)		
Operating Expenses:			
Current	$18	$ 36	$26
Deferred	15	(46)	7
Total Expense (Credit) to Operating Expenses	33	(10)	33
Nonoperating Income:			
Current	(29)	(15)	(20)
Deferred	31	(114)	21
Total Expense (Credit) to Nonoperating Income	2	(129)	1
Total Federal Income Tax Expense (Credit)	$35	$(139)	$34

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 statutory rate (35% in 1994 and 1993 and 34% in 1992), is reconciled to the amount of federal income tax recorded on the books as follows:

	1994	1993	1992
	(millions of dollars)		
Book Income (Loss) Before Federal Income Tax	$117	$(428)	$105
Tax (Credit) on Book Income (Loss) at Statutory Rate	$ 41	$(150)	$ 36
Increase (Decrease) in Tax:			
Write-off of Perry Unit 2	—	16	—
Write-off of phase-in deferrals	—	8	—
Depreciation	(3)	(12)	(6)
Rate Stabilization Program	(9)	(10)	(2)
Sale and leaseback transactions and amortization	5	5	5
Other items	1	4	1
Total Federal Income Tax Expense (Credit)	$ 35	$(139)	$ 34

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 $120 million loss with a corresponding $42 million reduction in federal income tax liability. Because of the alternative minimum tax (AMT), $24 million of the $42 million was realized in 1994. The remaining $18 million will not be realized until 1999.

In August 1993, the Revenue Reconciliation Act of 1993 was enacted. Retroactive to January 1, 1993, the top marginal corporate income tax rate increased to 35%. The change in tax rate did not materially impact the results of operations for 1993, but increased Accumulated Deferred Federal Income Taxes for the future tax obligation by approximately $29 million. Since the PUCO has historically permitted recovery of such taxes from customers when they become payable, the deferred charge, Amounts Due from Customers for Future Federal Income Taxes, also was increased by $29 million.

Under SFAS 109, temporary differences and carryforwards resulted in deferred tax assets of $178 million and deferred tax liabilities of $719 million at December 31, 1994 and deferred tax assets of $178 million and deferred tax liabilities of $649 million at December 31, 1993. These are summarized as follows:

	December 31, 1994	December 31, 1993
	(millions of dollars)	
Property, plant and equipment	$606	$534
Deferred carrying charges and operating expenses	83	79
Net operating loss carryforwards	(54)	(39)
Investment tax credits	(51)	(55)
Sale and leaseback transactions	(3)	—
Other	(40)	(48)
Net deferred tax liability	$541	$471

For tax purposes, net operating loss (NOL) carryforwards of approximately $154 million are available to reduce future taxable income and will expire in 2003 through 2009. The 35% tax effect of the NOLs is $54 million. Additionally, AMT credits of $69 million that may be carried forward indefinitely are available to reduce future regular 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 and an additional $10 million of pension costs for VTP benefits paid to retirees from corporate funds. The $10 million is not included in the pension data reported in the following table. A credit of $81 million resulting from a settlement of pension obligations through lump sum payments to almost all the VTP retirees partially offset the VTP expenses.

Pension and VTP costs (credits) for Centerior Energy and its subsidiaries for 1992 through 1994 were comprised of the following components:

	1994	1993	1992
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 13	$ 15	$ 15
Interest cost on projected benefit obligation	26	37	38
Actual return on plan assets	(2)	(65)	(24)
Net amortization and deferral	(34)	4	(45)
Net pension costs (credits)	3	(9)	(16)
VTP cost	—	205	—
Settlement gain	—	(81)	—
Net costs (credits)	$ 3	$115	$(16)

Pension and VTP costs (credits) for the Company and its pro rata share of the Service Company's costs were $1 million and $53 million for 1994 and 1993, respectively. The costs for 1992 were negligible.

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, 1994	December 31, 1993
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$278	$333
Nonvested benefits	2	37
Accumulated benefit obligation	280	370
Effect of future compensation levels	37	53
Total projected benefit obligation	317	423
Plan assets at fair market value	362	386
Funded status	45	(37)
Unrecognized net loss (gain) from variance between assumptions and experience	(79)	11
Unrecognized prior service cost	10	10
Transition asset at January 1, 1987 being amortized over 19 years	(39)	(43)
Net accrued pension liability	$(63)	$(59)

A September 30, 1994 measurement date was used for 1994 reporting. At December 31, 1994, the settlement (discount) 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, 1993, the settlement rate and long-term rate of return on plan assets assumptions were 7.25% and 8.75%, respectively. The long-term rate of annual compensation increase assumption was 4.25%. At December 31, 1994 and 1993, the Company's net accrued pension liability included in Retirement Benefits in the

Balance Sheet was $66 million and $65 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 ratemaking practices.

The components of the total postretirement benefit costs for 1994 and 1993 were as follows:

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

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

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

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,	
	1994	1993
	(millions of dollars)	
Accumulated postretirement benefit obligation attributable to:		
Retired participants	$(79)	$(88)
Other active plan participants	(7)	(9)
Accumulated postretirement benefit obligation	(86)	(97)
Unrecognized net loss (gain) from variance between assumptions and experience	(7)	5
Unamortized transition obligation	51	54
Accrued postretirement benefit cost	$(42)	$(38)

The Balance Sheet classification of Retirement Benefits at December 31, 1994 and 1993 includes only the Company's accrued postretirement benefit cost of $37 million and $33 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, 1994 measurement date was used for 1994 reporting. At December 31, 1994 and 1993, 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, 1994, the assumed annual health care cost trend rates (applicable to gross eligible charges) are 8.5% for medical and 8% for dental in 1995. 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, 1994 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, 1994, the principal amount of the loan and lease obligations guaranteed by the Company was $17 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, 1994 are listed in the following table.

	1994	1993	1992
	(thousands of shares)		
Subject to Mandatory Redemption:			
$100 par $11.00	—	—	(25)
9.375	(17)	(17)	(17)
25 par 2.81	(800)	(800)	—
Total	(817)	(817)	(42)

(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, 1994, the Company had $104 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 $11 million in 1995 and $2 million in each year 1996 through 1999.

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
25 par 2.81	400,000	1993	25

The annualized preferred dividend requirement at December 31, 1994 was $19 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 7.66% and 8.44%, respectively, in 1994.

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, 1994	December 31, 1994	1993
		(millions of dollars)	
First mortgage bonds:			
1997	6.125%	$ 31	$ 31
1998	10.00	1	1
1999	7.25	100	100
2000-2004	7.85	207	207
2010-2014	3.85	31	31
2015-2019	8.00	67	67
2020-2023	7.74	148	148
		585	585
Secured medium term notes due 1996-2021	8.44	250	250
Term bank loans due 1996	9.08	62	109
Notes due 1996-1997	9.49	25	43
Debentures due 2002	8.70	135	135
Pollution control notes due 1996-2015	12.11	99	105
Other — net	—	(2)	(2)
Total Long-Term Debt		$1,154	$1,225

Long-term debt matures during the next five years as follows: $71 million in 1995, $91 million in 1996, $40 million in 1997, $39 million in 1998 and $119 million in 1999.

The Company issued $141 million aggregate principal amount of secured medium-term notes in 1992 and 1993. The notes are secured by first mortgage bonds.

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 unsecured loan agreements of the Company contain covenants relating to capitalization ratios, fixed charge coverage ratios and limitations on secured financing other than through first mortgage bonds or certain other transactions. Two reimbursement agreements relating to separate letters of credit issued in connection with the sale and leaseback of Beaver Valley Unit 2 contain several financial covenants affecting the Company, Cleveland Electric and Centerior Energy. Among these are covenants relating to fixed charge coverage ratios and capitalization ratios. The write-offs recorded at December 31, 1993 caused the Company, Cleveland Electric and Centerior Energy to violate certain covenants contained in the two reimbursement agreements. The affected creditors waived those violations in exchange for a subordinate mortgage security interest on the properties of the Company and Cleveland Electric. The Company provided the same security interest to certain other creditors because their agreements require equal treatment. At December 31, 1994, the Company provided subordinate mortgage collateral for $152 million of unsecured debt, $228 million of bank letters of credit and a $205 million revolving credit facility. The bank letters of credit are joint and several obligations of the Company and Cleveland Electric and the revolving credit facility is an obligation of Centerior Energy that is jointly and severally guaranteed by the Company and Cleveland Electric.

(12) Short-Term Borrowing Arrangements

Centerior Energy has a $205 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 facility agreement as amended provides the participating banks with a subordinate mortgage security interest on the properties of the Company

and Cleveland Electric. 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, 1994. The facility agreement contains covenants relating to capitalization and fixed charge coverage ratios for the Company, Cleveland Electric and Centerior Energy.

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

(13) Financial Instruments

Except for the Nuclear Plant Decommissioning Trusts at December 31 1994, as discussed below, the estimated fair values at December 31, 1994 and 1993 of financial instruments that do not approximate their carrying amounts in the Balance Sheet are as follows:

	December 31,			
	1994		1993	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(millions of dollars)			
Assets:				
Nuclear Plant Decommissioning Trusts	$ 38	$ 38	$ 26	$ 27
Capitalization and Liabilities:				
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	18	19	40	42
Long-Term Debt (including current portion)	1,227	1,116	1,271	1,314

The Nuclear Plant Decommissioning Trusts at December 31, 1994 included $21 million of federal governmental securities and $14 million of municipal securities. The securities had the following maturities: $9 million due within one year; $7 million due in one to five years; $7 million due in six to 10 years; and $12 million due after 10 years. 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 is equal to the 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, 1994 and 1993 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, 1994.

	Quarters Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
	(millions of dollars)			
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
1993				
Operating Revenues	$215	$210	$239	$207
Operating Income (Loss)	39	42	17	(10)
Net Income (Loss)	18	20	(5)	(323)
Earnings (Loss) Available for Common Stock	12	14	(10)	(328)

Earnings for the quarter ended September 30, 1993 were decreased by $35 million as a result of the recording of $54 million of VTP pension-related benefits.

Earnings for the quarter ended December 31, 1993 were decreased as a result of year-end adjustments for the $232 million write-off of Perry Unit 2 (see Note 4(b)), the $241 million write-off of the phase-in deferrals (see Note 7) and $19 million of other charges. These adjustments decreased quarterly earnings by $345 million.

(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 PUCO and the Pennsylvania Public Utility Commission have approved the merger. In addition, the merger must be approved by share owners of the Company's preferred stock. Share owners of Cleveland Electric's preferred stock must approve 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. The merging companies plan to seek preferred stock share owner approval in mid-1995. The merger is expected to be effective in 1995.

For the merging companies, the combined pro forma operating revenues were $2.422 billion, $2.475 billion and $2.439 billion and the combined pro forma net income (loss) was $268 million, $(876) million and $276 million for the years 1994, 1993 and 1992, 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.

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
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
1990	224	175	236	78	713	150	863	—	863
1984	173	115	195	45	528	20	548	9	557

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
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
1990	174	262	111	73	79	(10)	21	710
1984	145	125	—	50	47	—	66	433

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
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
1990	153	3	5	43	9	213
1984	124	83	7	—	34	248

Income (Loss) (millions of dollars)

Year	Debt Interest	AFUDC—Debt	Net Income (Loss)	Preferred Stock Dividends	Earnings (Loss) Available for Common Stock
1994	$116	(1)	82	20	$ 62
1993	116	(1)	(289)	23	(312)
1992	122	(1)	71	24	47
1991	132	(1)	50	25	25
1990	135	(3)	81	25	56
1984	129	(35)	154	35	119

(a) Includes early retirement program expenses and other charges of $107 million in 1993.

(b) Includes write-off of phase-in deferrals of $241 million in 1993, consisting of $55 million of deferred operating expenses and $186 million of deferred carrying charges.

(c) In 1991, 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.

Year	Electric Sales (millions of KWH) Residential	Commercial	Industrial	Wholesale	Other	Total	Electric Customers (year end) Residential	Commercial	Industrial & Other	Total	Residential Usage Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
1994	2 056	1 711	4 099	2 548	499	10 913	256 998	25 921	3 965	286 884	8 044	11.04¢	$888.30
1993	2 039	1 672	3 776	2 146	490	10 123	255 109	26 049	4 076	285 234	7 997	11.23	897.65
1992	1 941	1 619	3 563	2 753	478	10 354	255 299	25 870	4 372	285 541	7 632	11.08	845.99
1991	2 041	1 683	3 543	2 587	482	10 336	254 500	26 044	4 444	284 988	7 990	11.26	897.41
1990	1 950	1 614	3 617	2 333	496	10 010	253 965	25 822	4 555	284 342	7 692	11.48	882.99
1984	1 958	1 398	3 444	473	440	7 713	243 912	23 891	3 920	271 723	8 045	8.81	709.09

Year	Load (MW & %) Net Seasonal Capability	Peak Load	Capacity Margin	Load Factor	Energy (millions of KWH) Company Generated: Fossil	Company Generated: Nuclear	Company Generated: Total	Purchased Power	Total	Fuel: Fuel Cost Per KWH	Efficiency—BTU Per KWH
1994	1 729	1 620	6.3%	64.7%	5 160	5 419	10 579	773	11 352	1.35¢	10 298
1993	1 729	1 568	9.3	64.3	5 548	4 791	10 339	196	10 535	1.42	10 146
1992	1 762	1 514	14.1	63.2	4 656	6 293	10 949	(82)	10 867	1.41	10 284
1991	1 759	1 510	14.2	64.5	4 848	6 003	10 851	95	10 946	1.44	10 327
1990	1 751	1 516	13.4	63.0	5 535	4 219	9 754	902	10 656	1.50	10 220
1984	1 688	1 327	21.4	68.2	5 181	2 091	7 272	888	8 160	1.73	10 193

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
1994	$2 899	892	2 007	30	125	$2 162	$ 41	$3 502
1993	2 837	788	2 049	40	142	[illegible] 231	43	3 510
1992	2 847	760	2 087	280	164	[illegible]	44	3 939
1991	2 692	709	1 983	308	198	2 [illegible]	54	3 926
1990	2 604	640	1 964	349	224	2 53[illegible]	87	3 913
1984	1 373	365	1 008	1 413	197*(e)*	2 618	356	2 936

Capitalization (millions of dollars & %)

Year	Common Stock Equity		Preferred Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
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
1990	881	39	66	3	210	9	1 097	49	2 254
1984	814	36	158	7	200	9	1 110	48	2 282

(d) Includes write-off of Perry Unit 2 of $232 million in 1993.

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

INDEX TO SCHEDULES

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable.

CENTERIOR ENERGY CORPORATION AND SUBSIDIARIES

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR TH[E] YEARS ENDED DECEMBER 31, 1994, 1993 AND 1992

(Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income Statement	Additions: Other	Deductions: Deductions from Reserves	Deductions: Other	Balance at End of Period
Reflected as Reductions to the Related Assets:						
Accumulated Provision for Uncollectible Accounts (Deduction from Amounts Due from Customers and Others)						
1994	$3,703	$12,779 (a)	$6,047 (b)	$19,010 (a)(c)	$0	$3,519
1993	3,723	14,139 (a)	3,516 (b)	17,675 (a)(c)	0	3,703
1992	3,703	19,673 (a)	2,376 (b)	22,029 (a)(c)	0	3,723
Reserve for Perry Unit 2 Allowance for Funds Used During Construction (Deduction from Perry Unit 2)						
1994	$0	$0	$0	$0	$0	$0
1993	212,693	0	0	212,693 (d)	0	0
1992	212,693	0	0	0	0	212,693

(a) Includes a provision and corresponding write-off of uncollectible accounts of $4,695,000, $4,550,000 and $5,968,000 in 1994, 1993 and 1992, respectively, relating to customers which qualify for the PUCO mandated Percentage of Income Payment Plan (PIPP). Such uncollectible accounts are recovered through a separate PUCO approved surcharge tariff.

(b) Includes amounts for collection of accounts previously written off and deferral of PIPP uncollectibles in excess of the amounts included in the last base rate cases. The amounts deferred for future recovery were $2,382,000, $971,000 and $37,000 in 1994, 1993 and 1992, respectively.

(c) Uncollectible accounts written off.

(d) Write-off of Perry Unit 2 investment.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND SUBSIDIARIES

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 1994, 1993 AND 1992

(Thousands of Dollars)

		Additions		Deductions		
Description	Balance at Beginning of Period	Charged to Income Statement	Other	Deductions from Reserves	Other	Balance at End of Period
Reflected as Reductions to the Related Assets:						
Accumulated Provision for Uncollectible Accounts (Deduction from Amounts Due from Customers and Others)						
1994	$2,313	$8,354 (a)	$4,508 (b)	$13,046 (a)(c)	$0	$2,129
1993	2,333	9,280 (a)	1,813 (b)	11,113 (a)(c)	0	2,313
1992	2,313	16,359 (a)	1,309 (b)	17,648 (a)(c)	0	2,333
Reserve for Perry Unit 2 Allowance for Funds Used During Construction (Deduction from Perry Unit 2)						
1994	$0	$0	$0	$0	$0	$0
1993	124,398	0	0	124,398 (d)	0	0
1992	124,398	0	0	0	0	124,398

(a) Includes a provision and corresponding write-off of uncollectible accounts of $2,499,000, $2,447,000 and $5,269,000 in 1994, 1993 and 1992, respectively, relating to customers which qualify for the PUCO mandated Percentage of Income Payment Plan (PIPP). Such uncollectible accounts are recovered through a separate PUCO approved surcharge tariff.

(b) Includes amounts for collection of accounts previously written off and deferral of PIPP uncollectibles in excess of the amount included in the last base rate case. The amounts deferred for future recovery were $1,971,000 and $507,000 in 1994 and 1993, respectively.

(c) Uncollectible accounts written off.

(d) Write-off of Perry Unit 2 investment.

THE TOLEDO EDISON COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 1994, 1993 AND 1992

(Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income Statement	Additions: Other	Deductions: Deductions from Reserves	Deductions: Other	Balance at End of Period
Reflected as Reductions to the Related Assets:						
Accumulated Provision for Uncollectible Accounts (Deduction from Amounts Due from Customers and Others)						
1994	$1,390	$4,425 (a)	$1,539 (b)	$5,964 (a)(c)	$0	$1,390
1993	1,390	4,859 (a)	1,703 (b)	6,562 (a)(c)	0	1,390
1992	1,390	3,314 (a)	1,067 (b)	4,381 (a)(c)	0	1,390
Reserve for Perry Unit 2 Allowance for Funds Used During Construction (Deduction from Perry Unit 2)						
1994	$0	$0	$0	$0	$0	$0
1993	88,295	0	0	88,295 (d)	0	0
1992	88,295	0	0	0	0	88,295

(a) Includes a provision and corresponding write-off of uncollectible accounts of $2,196,000, $2,103,000 and $699,000 in 1994, 1993 and 1992, respectively, relating to customers which qualify for the PUCO mandated Percentage of Income Payment Plan (PIPP). Such uncollectible accounts are recovered through a separate PUCO approved surcharge tariff.

(b) Includes amounts for collection of accounts previously written off and deferral of PIPP uncollectibles in excess of the amount included in the last base rate case. The amounts deferred for future recovery were $411,000, $464,000 and $37,000 in 1994, 1993 and 1992, respectively.

(c) Uncollectible accounts written off.

(d) Write-off of Perry Unit 2 investment.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND SUBSIDIARIES
AND THE TOLEDO EDISON COMPANY
COMBINED PRO FORMA CONDENSED FINANCIAL STATEMENTS

The following pro forma condensed balance sheets and income statements give effect to the agreement between Cleveland Electric and Toledo Edison to merge Toledo Edison into Cleveland Electric. These statements are unaudited and based on accounting for the merger on a method similar to a pooling of interests. These statements combine the two companies' historical balance sheets at December 31, 1994 and December 31, 1993 and their historical income statements for each of the three years ended December 31, 1994.

The following pro forma data is not necessarily indicative of the results of operations or the financial condition which would have been reported had the merger been in effect during those periods or which may be reported in the future. The statements should be read in conjunction with the accompanying notes and with the audited financial statements of both Cleveland Electric and Toledo Edison.

COMBINED PRO FORMA CONDENSED BALANCE SHEETS OF CLEVELAND ELECTRIC AND TOLEDO EDISON
(Unaudited)
(Millions of Dollars)

	At December 31, 1994			
	Historical			
	Cleveland Electric	Toledo Edison	Adjustments	Pro Forma Totals
Assets				
Property, Plant and Equipment	$7,637	$3,435	$ -	$11,072
Less: Accumulated Depreciation and Amortization	2,486	1,273	-	3,759
Net Property, Plant and Equipment	5,151	2,162	-	7,313
Current Assets	584	322	(22)(A)	884
Deferred Charges and Other Assets	1,416	1,018	(7)(B)	2,427
Total Assets	$7,151	$3,502	$(29)	$10,624
Capitalization and Liabilities				
Capitalization:				
Common Stock Equity	$1,058	$ 685	$ -	$ 1,743
Preferred Stock:				
With Mandatory Redemption Provisions	246	7	-	253
Without Mandatory Redemption Provisions	241	210	-	451
Long-Term Debt	2,543	1,154	-	3,697
Total Capitalization	4,088	2,056	-	6,144
Current Liabilities	958	316	(24)(A)	1,250
Deferred Credits and Other Liabilities	2,105	1,130	(5)(A,B)	3,230
Total Capitalization and Liabilities	$7,151	$3,502	$(29)	$10,624

	At December 31, 1993			
	Historical			
	Cleveland Electric	Toledo Edison	Adjust-ments	Pro Forma Totals
Assets				
Property, Plant and Equipment	$7,538	$3,402	$ -	$10,940
Less: Accumulated Depreciation and Amortization	2,309	1,171	-	3,480
Net Property, Plant and Equipment	5,229	2,231	-	7,460
Current Assets	632	314	(20)(A)	926
Deferred Charges and Other Assets	1,298	965	(9)(B)	2,254
Total Assets	$7,159	$3,510	$(29)	$10,640
Capitalization and Liabilities				
Capitalization:				
Common Stock Equity	$1,040	$ 623	$ (1)(R)	$ 1,662
Preferred Stock:				
With Mandatory Redemption Provisions	285	28	-	313
Without Mandatory Redemption Provisions	241	210	-	451
Long-Term Debt	2,793	1,225	1(R)	4,019
Total Capitalization	4,359	2,086	-	6,445
Current Liabilities	733	329	(21)(A)	1,041
Deferred Credits and Other Liabilities	2,067	1,095	(8)(A,B)	3,154
Total Capitalization and Liabilities	$7,159	$3,510	$(29)	$10,640

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND SUBSIDIARIES
AND THE TOLEDO EDISON COMPANY
COMBINED PRO FORMA CONDENSED FINANCIAL STATEMENTS

The following pro forma condensed balance sheets and income statements give effect to the agreement between Cleveland Electric and Toledo Edison to merge Toledo Edison into Cleveland Electric. These statements are unaudited and based on accounting for the merger on a method similar to a pooling of interests. These statements combine the two companies' historical balance sheets at December 31, 1994 and December 31, 1993 and their historical income statements for each of the three years ended December 31, 1994.

The following pro forma data is not necessarily indicative of the results of operations or the financial condition which would have been reported had the merger been in effect during those periods or which may be reported in the future. The statements should be read in conjunction with the accompanying notes and with the audited financial statements of both Cleveland Electric and Toledo Edison.

COMBINED PRO FORMA CONDENSED BALANCE SHEETS
OF CLEVELAND ELECTRIC AND TOLEDO EDISON
(Unaudited)
(Millions of Dollars)

	At December 31, 1994			
	Historical			
	Cleveland Electric	Toledo Edison	Adjustments	Pro Forma Totals
Assets				
Property, Plant and Equipment	$7,637	$3,435	$ -	$11,072
Less: Accumulated Depreciation and Amortization	2,486	1,273	-	3,759
Net Property, Plant and Equipment	5,151	2,162	-	7,313
Current Assets	584	322	(22)(A)	884
Deferred Charges and Other Assets	1,416	1,018	(7)(B)	2,427
Total Assets	$7,151	$3,502	$(29)	$10,624
Capitalization and Liabilities				
Capitalization:				
Common Stock Equity	$1,058	$ 685	$ -	$ 1,743
Preferred Stock:				
With Mandatory Redemption Provisions	246	7	-	253
Without Mandatory Redemption Provisions	241	210	-	451
Long-Term Debt	2,543	1,154	-	3,697
Total Capitalization	4,088	2,056	-	6,144
Current Liabilities	958	316	(24)(A)	1,250
Deferred Credits and Other Liabilities	2,105	1,130	(5)(A,B)	[illegible],230
Total Capitalization and Liabilities	$7,151	$3,502	$(29)	$10,624

	At December 31, 1993			
	Historical			
	Cleveland Electric	Toledo Edison	Adjust- ments	Pro Forma Totals
Assets				
Property, Plant and Equipment	$7,538	$3,402	$ -	$10,940
Less: Accumulated Depreciation and Amortization	2,309	1,171	-	3,480
Net Property, Plant and Equipment	5,229	2,231	-	7,460
Current Assets	632	314	(20)(A)	926
Deferred Charges and Other Assets	1,298	965	(9)(B)	2,254
Total Assets	$7,159	$3,510	$(29)	$10,640
Capitalization and Liabilities				
Capitalization:				
Common Stock Equity	$1,040	$ 623	$ (1)(R)	$ 1,662
Preferred Stock:				
With Mandatory Redemption Provisions	285	28	-	313
Without Mandatory Redemption Provisions	241	210	-	451
Long-Term Debt	2,793	1,225	1(R)	4,019
Total Capitalization	4,359	2,086	-	6,445
Current Liabilities	733	329	(21)(A)	1,041
Deferred Credits and Other Liabilities	2,067	1,095	(8)(A,B)	3,154
Total Capitalization and Liabilities	$7,159	$3,510	$(29)	$10,640

COMBINED PRO FORMA CONDENSED INCOME STATEMENTS
OF CLEVELAND ELECTRIC AND TOLEDO EDISON
(Unaudited)
(Millions of Dollars)

	Year Ended December 31, 1994			
	Historical			
	Cleveland Electric	Toledo Edison	Adjust-ments	Pro Forma Totals
Operating Revenues	$1,698	$ 865	$(141)(C)	$2,422
Operating Expenses	1,302	685	(143)(C,D)	1,844
Operating Income	396	180	2	578
Nonoperating Income	31	17	(2)(D,E,R)	46
Income Before Interest Charges	427	197	-	624
Interest Charges	242	115	(1)(E)	356
Net Income	185	82	1	268
Preferred Dividend Requirements	45	20	1(R)	66
Earnings Available for Common Stock	$ 140	$ 62	$ -	$ 202

	Year Ended December 31, 1993			
	Historical			
	Cleveland Electric	Toledo Edison	Adjust-ments	Pro Forma Totals
Operating Revenues	$1,751	$ 871	$(147)(C)	$2,475
Operating Expenses	1,529	782	(148)(C,D)	2,163
Operating Income	222	89	1	312
Nonoperating (Loss)	(569)	(263)	(1)(D)	(833)
(Loss) Before Interest Charges	(347)	(174)	-	(521)
Interest Charges	240	115	-	355
Net (Loss)	(587)	(289)	-	(876)
Preferred Dividend Requirements	45	23	-	68
(Loss) Available for Common Stock	$ (632)	$(312)	$ -	$ (944)

	Year Ended December 31, 1992			
	Historical			
	Cleveland Electric	Toledo Edison	Adjust-ments	Pro Forma Totals
Operating Revenues	$1,743	$ 845	$(149)(C)	$2,439
Operating Expenses	1,358	695	(150)(C,D)	1,903
Operating Income	385	150	1	536
Nonoperating Income	63	42	(1)(D)	104
Income Before Interest Charges	448	192	-	640
Interest Charges	243	121	-	364
Net Income	205	71	-	276
Preferred Dividend Requirements	41	24	-	65
Earnings Available for Common Stock	$ 164	$ 47	$ -	$ 211

NOTES TO COMBINED PRO FORMA CONDENSED BALANCE SHEETS AND INCOME STATEMENTS
(Unaudited)

The Pro Forma Financial Statements include the following adjustments:

(A) Elimination of intercompany accounts and notes receivable and accounts and notes payable.
(B) Reclassification of prepaid pension costs.
(C) Elimination of intercompany operating revenues and operating expenses.
(D) Elimination of intercompany working capital transactions.
(E) Elimination of intercompany interest income and interest expense.
(R) Rounding adjustments.

EXHIBIT INDEX

The exhibits designated with an asterisk (*) are filed herewith. The exhibits not so designated have previously been filed with the SEC in the file indicated in parenthesis following the description of such exhibits and are incorporated herein by reference. An exhibit designated with a pound sign (#) is a management contract or compensatory plan or arrangement.

COMMON EXHIBITS

(The following documents are exhibits to the reports of Centerior Energy, Cleveland Electric and Toledo Edison.)

Exhibit Number	Document
10b(1)(a)	CAPCO Administration Agreement dated November 1, 1971, as of September 14, 1967, among the CAPCO Group members regarding the organization and procedures for implementing the objectives of the CAPCO Group (Exhibit 5(p), Amendment No. 1, File No. 2-42230, filed by Cleveland Electric).
10b(1)(b)	Amendment No. 1, dated January 4, 1974, to CAPCO Administration Agreement among the CAPCO Group members (Exhibit 5(c)(3), File No. 2-68906, filed by Ohio Edison).
10b(2)	CAPCO Transmission Facilities Agreement dated November 1, 1971, as of September 14, 1967, among the CAPCO Group members regarding the installation, operation and maintenance of transmission facilities to carry out the objectives of the CAPCO Group (Exhibit 5(q), Amendment No. 1, File No. 2-42230, filed by Cleveland Electric).
10b(2)(1)	Amendment No. 1 to CAPCO Transmission Facilities Agreement, dated December 23, 1993 and effective as of January 1, 1993, among the CAPCO Group members regarding requirements for payment of invoices at specified times, for payment of interest on non-timely paid invoices, for restricting adjustment of invoices after a four-year period, and for revising the method for computing the Investment Responsibility charge for use of a member's transmission facilities (Exhibit 10b(2)(1), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(3)	CAPCO Basic Operating Agreement As Amended January 1, 1993 among the CAPCO Group members regarding coordinated operation of the members' systems (Exhibit 10b(3), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(4)	Agreement for the Termination or Construction of Certain Agreements By and Among the CAPCO Group members, dated December 23, 1993 and effective as of September 1, 1980 (Exhibit 10b(4), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(5)	Construction Agreement, dated July 22, 1974, among the CAPCO Group members and relating to the Perry Nuclear Plant (Exhibit 5(yy), File No. 2-52251, filed by Toledo Edison).

Exhibit Number	Document
10b(6)	Contract, dated as of December 5, 1975, among the CAPCO Group members for the construction of Beaver Valley Unit No. 2 (Exhibit 5(g), File No. 2-52996, filed by Cleveland Electric).
10b(7)	Amendment No. 1, dated May 1, 1977, to Contract, dated as of December 5, 1975, among the CAPCO Group members for the construction of Beaver Valley Unit No. 2 (Exhibit 5(d)(4), File No. 2-60109, filed by Ohio Edison).
10d(1)(a)	Form of Collateral Trust Indenture among CTC Beaver Valley Funding Corporation, Cleveland Electric, Toledo Edison and Irving Trust Company, as Trustee (Exhibit 4(a), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(1)(b)	Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(1)(a) above, including form of Secured Lease Obligation Bond (Exhibit 4(b), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(1)(c)	Form of Collateral Trust Indenture among Beaver Valley II Funding Corporation, The Cleveland Electric Illuminating Company and The Toledo Edison Company and The Bank of New York, as Trustee (Exhibit (4)(a), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).
10d(1)(d)	Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(1)(c) above, including form of Secured Lease Obligation Bond (Exhibit (4)(b), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).
10d(2)(a)	Form of Collateral Trust Indenture among CTC Mansfield Funding Corporation, Cleveland Electric, Toledo Edison and IBJ Schroder Bank & Trust Company, as Trustee (Exhibit 4(a), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(2)(b)	Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(2)(a) above, including forms of Secured Lease Obligation Bonds (Exhibit 4(b), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(3)(a)	Form of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessees (Exhibit 4(c), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(3)(b)	Form of Amendment No. 1 to Facility Lease constituting Exhibit 10d(3)(a) above (Exhibit 4(e), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

Exhibit Number	Document
10d(4)(a)	Form of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessees (Exhibit 4(d), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(4)(b)	Form of Amendment No. 1 to Facility Lease constituting Exhibit 10d(4)(a) above (Exhibit 4(f), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(5)(a)	Form of Facility Lease dated as of September 30, 1987 between Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessees (Exhibit 4(c), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(5)(b)	Form of Amendment No. 1 to the Facility Lease constituting Exhibit 10d(5)(a) above (Exhibit 4(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(6)(a)	Form of Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, CTC Beaver Valley Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(a), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(6)(b)	Form of Amendment No. 1 to Participation Agreement constituting Exhibit 10d(6)(a) above (Exhibit 28(c), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(7)(a)	Form of Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, CTC Beaver Valley Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(b), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(7)(b)	Form of Amendment No. 1 to Participation Agreement constituting Exhibit 10d(7)(a) above (Exhibit 28(d), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

Exhibit Number	Document
10d(8)(a)	Form of Participation Agreement dated as of September 30, 1987 among the Owner Participant named therein, the Original Loan Participants listed in Schedule II thereto, as Original Loan Participants, CTC Mansfield Funding Corporation, Meridian Trust Company, as Owner Trustee, IBJ Schroder Bank & Trust Company, as Indenture Trustee, and Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(a), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(8)(b)	Form of Amendment No. 1 to the Participation Agreement constituting Exhibit 10d(8)(a) above (Exhibit 28(b), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(9)	Form of Ground Lease dated as of September 15, 1987 between Toledo Edison, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Tenant (Exhibit 28(e), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(10)	Form of Site Lease dated as of September 30, 1987 between Toledo Edison, Lessor, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Tenant (Exhibit 28(c), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(11)	Form of Site Lease dated as of September 30, 1987 between Cleveland Electric, Lessor, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Tenant (Exhibit 28(d), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(12)	Form of Amendment No. 1 to the Site Leases constituting Exhibits 10d(10) and 10d(11) above (Exhibit 4(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(13)	Form of Assignment, Assumption and Further Agreement dated as of September 15, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Cleveland Electric, Duquesne, Ohio Edison, Pennsylvania Power and Toledo Edison (Exhibit 28(f), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(14)	Form of Additional Support Agreement dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, and Toledo Edison (Exhibit 28(g), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

Exhibit Number	Document
10d(15)	Form of Support Agreement dated as of September 30, 1987 between Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named there, Toledo Edison, Cleveland Electric, Duquesne, Ohio Edison and Pennsylvania Power (Exhibit 28(e), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(16)	Form of Indenture, Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Toledo Edison, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(h), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(17)	Form of Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Toledo Edison, Seller, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(18)	Form of Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Cleveland Electric, Seller, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(g), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(19)	Forms of Refinancing Agreement, including exhibits thereto, among the Owner Participant named therein, as Owner Participant, CTC Beaver Valley Funding Corporation, as Funding Corporation, Beaver Valley II Funding Corporation, as New Funding Corporation, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, as Lessees (Exhibit (28)(e)(i), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).
10e(1)	#Employment agreement, dated May 25, 1993, between Centerior Service Company and Donald C. Shelton effective June 4, 1993 and extending until June 30, 1995 (Exhibit 10e(1), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10e(2)	#Employment agreement, dated February 2, 1994 and accepted on February 8, 1994, between Centerior Energy and Al R. Temple effective through December 1996 (Exhibit 10e(2), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).

Exhibit Number	Document
18a	Letter regarding change in accounting principles (Exhibit 18, June 30, 1991 Form 10-Q, File Nos. 1-9130, 1-2323 and 1-3583).
99a	Financial Statements of the Centerior Energy Corporation Employee Savings Plan for the fiscal year ended December 31, 1994 (to be filed by amendment).

CENTERIOR ENERGY EXHIBITS

Exhibit Number	Document
3a	Amended Articles of Incorporation of Centerior Energy effective April 29, 1986 (Exhibit 4(a), File No. 33-4790).
3b	Regulations of Centerior Energy effective April 28, 1987 (Exhibit 3b, 1987 Form 10-K, File No. 1-9130).
10a (CEC)	*Indemnity Agreements between Centerior and certain of its current directors and officers.
21 (CEC)	*List of subsidiaries.
23a (CEC)	*Consent of Independent Accountants.
23b (CEC)	*Consent of Counsel for Centerior Energy.
24 (CEC)	*Powers of Attorney of Centerior Energy directors and officers required to sign the Report.
27 (CEC)	*Financial Data Schedule for the period ended December 31, 1994.

CLEVELAND ELECTRIC EXHIBITS

Exhibit Number	Document
3a	Amended Articles of Incorporation of Cleveland Electric, as amended, effective May 28, 1993 (Exhibit 3a, 1993 Form 10-K, File No. 1-2323).
3b	Regulations of Cleveland Electric, dated April 29, 1981, as amended effective October 1, 1988 and April 24, 1990 (Exhibit 3b, 1990 Form 10-K, File No. 1-2323).
4b(1)	Mortgage and Deed of Trust between Cleveland Electric and Guaranty Trust Company of New York (now Morgan Guaranty Trust Company of New York), as Trustee, dated July 1, 1940 (Exhibit 7(a), File No. 2-4450).
	Supplemental Indentures between Cleveland Electric and the Trustee, supplemental to Exhibit 4b(1), dated as follows:

Exhibit Number	Document
4b(2)	July 1, 1940 (Exhibit 7(b), File No. 2-4450).
4b(3)	August 18, 1944 (Exhibit 4(c), File No. 2-9887).
4b(4)	December 1, 1947 (Exhibit 7(d), File No. 2-7306).
4b(5)	September 1, 1950 (Exhibit 7(c), File No. 2-8587).
4b(6)	June 1, 1951 (Exhibit 7(f), File No. 2-8994).
4b(7)	May 1, 1954 (Exhibit 4(d), File No. 2-10830).
4b(8)	March 1, 1958 (Exhibit 2(a)(4), File No. 2-13839).
4b(9)	April 1, 1959 (Exhibit 2(a)(4), File No. 2-14753).
4b(10)	December 20, 1967 (Exhibit 2(a)(4), File No. 2-30759).
4b(11)	January 15, 1969 (Exhibit 2(a)(5), File No. 2-30759).
4b(12)	November 1, 1969 (Exhibit 2(a)(4), File No. 2-35008).
4b(13)	June 1, 1970 (Exhibit 2(a)(4), File No. 2-37235).
4b(14)	November 15, 1970 (Exhibit 2(a)(4), File No. 2-38460).
4b(15)	May 1, 1974 (Exhibit 2(a)(4), File No. 2-50537).
4b(16)	April 15, 1975 (Exhibit 2(a)(4), File No. 2-52995).
4b(17)	April 16, 1975 (Exhibit 2(a)(4), File No. 2-53309).
4b(18)	May 28, 1975 (Exhibit 2(c), June 5, 1975 Form 8-A, File No. 1-2323).
4b(19)	February 1, 1976 (Exhibit 3(d)(6), 1975 Form 10-K, File No. 1-2323).
4b(20)	November 23, 1976 (Exhibit 2(a)(4), File No. 2-57375).
4b(21)	July 26, 1977 (Exhibit 2(a)(4), File No. 2-59401).
4b(22)	September 27, 1977 (Exhibit 2(a)(5), File No. 2-67221).
4b(23)	May 1, 1978 (Exhibit 2(b), June 30, 1978 Form 10-Q, File No. 1-2323).
4b(24)	September 1, 1979 (Exhibit 2(a), September 30, 1979 Form 10-Q, File No. 1-2323).
4b(25)	April 1, 1980 (Exhibit 4(a)(2), September 30, 1980 Form 10-Q, File No. 1-2323).
4b(26)	April 15, 1980 (Exhibit 4(b), September 30, 1980 Form 10-Q, File No. 1-2323).
4b(27)	May 28, 1980 (Exhibit 2(a)(4), Amendment No. 1, File No. 2-67221).
4b(28)	June 9, 1980 (Exhibit 4(d), September 30, 1980 Form 10-Q, File No. 1-2323).
4b(29)	December 1, 1980 (Exhibit 4(b)(29), 1980 Form 10-K, File No. 1-2323).
4b(30)	July 28, 1981 (Exhibit 4(a), September 30, 1981, Form 10-Q, File No. 1-2323).
4b(31)	August 1, 1981 (Exhibit 4(b), September 30, 1981, Form 10-Q, File No. 1-2323).
4b(32)	March 1, 1982 (Exhibit 4(b)(3), Amendment No. 1, File No. 2-76029).
4b(33)	July 15, 1982 (Exhibit 4(a), September 30, 1982 Form 10-Q, File No. 1-2323).
4b(34)	September 1, 1982 (Exhibit 4(a)(1), September 30, 1982 Form 10-Q, File No. 1-2323).
4b(35)	November 1, 1982 (Exhibit 4(a)(2), September 30, 1982 Form 10-Q, File No. 1-2323).
4b(36)	November 15, 1982 (Exhibit 4(b)(36), 1982 Form 10-K, File No. 1-2323).

Exhibit Number	Document
4b(37)	May 24, 1983 (Exhibit 4(a), June 30, 1983 Form 10-Q, File No. 1-2323).
4b(38)	May 1, 1984 (Exhibit 4, June 30, 1984 Form 10-Q, File No. 1-2323).
4b(39)	May 23, 1984 (Exhibit 4, May 22, 1984 Form 8-K, File No. 1-2323).
4b(40)	June 27, 1984 (Exhibit 4, June 11, 1984 Form 8-K, File No. 1-2323).
4b(41)	September 4, 1984 (Exhibit 4b(41), 1984 Form 10-K, File No. 1-2323).
4b(42)	November 14, 1984 (Exhibit 4b(42), 1984 Form 10-K, File No. 1-2323).
4b(43)	November 15, 1984 (Exhibit 4b(43), 1984 Form 10-K, File No. 1-2323).
4b(44)	April 15, 1985 (Exhibit 4(a), May 8, 1985 Form 8-K, File No. 1-2323).
4b(45)	May 28, 1985 (Exhibit 4(b), May 8, 1985 Form 8-K, File No. 1-2323).
4b(46)	August 1, 1985 (Exhibit 4, September 30, 1985 Form 10-Q, File No. 1-2323).
4b(47)	September 1, 1985 (Exhibit 4, September 30, 1985 Form 8-K, File No. 1-2323).
4b(48)	November 1, 1985 (Exhibit 4, January 31, 1986 Form 8-K, File No. 1-2323).
4b(49)	April 15, 1986 (Exhibit 4, March 31, 1986 Form 10-Q, File No. 1-2323).
4b(50)	May 14, 1986 (Exhibit 4(a), June 30, 1986 Form 10-Q, File No. 1-2323).
4b(51)	May 15, 1986 (Exhibit 4(b), June 30, 1986 Form 10-Q, File No. 1-2323).
4b(52)	February 25, 1987 (Exhibit 4b(52), 1986 Form 10-K, File No. 1-2323).
4b(53)	October 15, 1987 (Exhibit 4, September 30, 1987 Form 10-Q, File No. 1-2323).
4b(54)	February 24, 1988 (Exhibit 4b(54), 1987 Form 10-K, File No. 1-2323).
4b(55)	September 15, 1988 (Exhibit 4b(55), 1988 Form 10-K, File No. 1-2323).
4b(56)	May 15, 1989 (Exhibit 4(a)(2)(i), File No. 33-32724).
4b(57)	June 13, 1989 (Exhibit 4(a)(2)(ii), File No. 33-32724).
4b(58)	October 15, 1989 (Exhibit 4(a)(2)(iii), File No. 33-32724).
4b(59)	January 1, 1990 (Exhibit 4b(59), 1989 Form 10-K, File No. 1-2323).
4b(60)	June 1, 1990 (Exhibit 4(a), September 30, 1990 Form 10-Q, File No. 1-2323).
4b(61)	August 1, 1990 (Exhibit 4(b), September 30, 1990 Form 10-Q, File No. 1-2323).
4b(62)	May 1, 1991 (Exhibit 4(a), June 30, 1991 Form 10-Q, File No. 1-2323).

Exhibit Number	Document
4b(63)	May 1, 1992 (Exhibit 4(a)(3), File No. 33-48845).
4b(64)	July 31, 1992 (Exhibit 4(a)(3), File No. 33-57292).
4b(65)	January 1, 1993 (Exhibit 4b(65), 1992 Form 10-K, File No. 1-2323).
4b(66)	February 1, 1993 (Exhibit 4b(66), 1992 Form 10-K, File No. 1-2323).
4b(67)	May 20, 1993 (Exhibit 4(a), July 14, 1993 Form 8-K, File No. 1-2323).
4b(68)	June 1, 1993 (Exhibit 4(b), July 14, 1993 Form 8-K, File No. 1-2323).
4b(69)	September 15, 1994 (Exhibit 4(a), September 30, 1994 Form 10-Q, File No. 1-2323).
4c	Open-End Subordinate Indenture of Mortgage between The Cleveland Electric Illuminating Company and Bank One, Columbus, N.A., as Trustee, Dated as of June 1, 1994 (Exhibit 4(a), August 26, 1994 Form 8-K, File No. 1-2323).
10	#1978 Key Employee Stock Option Plan (Exhibit 1, File No. 2-61712).
23a (CEI)	*Consent of Independent Accountants.
23b (CEI)	*Consent of Counsel for Cleveland Electric.
24 (CEI)	*Powers of Attorney of Cleveland Electric directors and officers required to sign the Report.
27 (CEI)	*Financial Data Schedule for the period ended December 31, 1994.

TOLEDO EDISON EXHIBITS

Exhibit Number	Document
3a	Amended Articles of Incorporation of Toledo Edison, as amended effective October 2, 1992 (Exhibit 3a, 1992 Form 10-K, File No. 1-3583).
3b	Code of Regulations of Toledo Edison dated January 28, 1987, as amended effective July 1 and October 1, 1988 and April 24, 1990 (Exhibit 3b, 1990 Form 10-K, File No. 1-3583).
4b(1)	Indenture, dated as of April 1, 1947, between the Company and The Chase National Bank of the City of New York (now The Chase Manhattan Bank (National Association)) (Exhibit 2(b), File No. 2-26908).
	Supplemental Indentures between Toledo Edison and the Trustee, Supplemental to Exhibit 4b(1), dated as follows:

Exhibit Number	Document
4b(2)	September 1, 1948 (Exhibit 2(d), File No. 2-26908).
4b(3)	April 1, 1949 (Exhibit 2(e), File No. 2-26908).
4b(4)	December 1, 1950 (Exhibit 2(f), File No. 2-26908).
4b(5)	March 1, 1954 (Exhibit 2(g), File No. 2-26908).
4b(6)	February 1, 1956 (Exhibit 2(h), File No. 2-26908).
4b(7)	May 1, 1958 (Exhibit 5(g), File No. 2-59794).
4b(8)	August 1, 1967 (Exhibit 2(c), File No. 2-26908).
4b(9)	November 1, 1970 (Exhibit 2(c), File No. 2-38569).
4b(10)	August 1, 1972 (Exhibit 2(c), File No. 2-44873).
4b(11)	November 1, 1973 (Exhibit 2(c), File No. 2-49428).
4b(12)	July 1, 1974 (Exhibit 2(c), File No. 2-51429).
4b(13)	October 1, 1975 (Exhibit 2(c), File No. 2-54627).
4b(14)	June 1, 1976 (Exhibit 2(c), File No. 2-56396).
4b(15)	October 1, 1978 (Exhibit 2(c), File No. 2-62568).
4b(16)	September 1, 1979 (Exhibit 2(c), File No. 2-65350).
4b(17)	September 1, 1980 (Exhibit 4(s), File No. 2-69190).
4b(18)	October 1, 1980 (Exhibit 4(c), File No. 2-69190).
4b(19)	April 1, 1981 (Exhibit 4(c), File No. 2-71580).
4b(20)	November 1, 1981 (Exhibit 4(c), File No. 2-74485).
4b(21)	June 1, 1982 (Exhibit 4(c), File No. 2-77763).
4b(22)	September 1, 1982 (Exhibit 4(x), File No. 2-87323).
4b(23)	April 1, 1983 (Exhibit 4(c), March 31, 1983 Form 10-Q, File No. 1-3583).
4b(24)	December 1, 1983 (Exhibit 4(x), 1983 Form 10-K, File No. 1-3583).
4b(25)	April 1, 1984 (Exhibit 4(c), File No. 2-90059).
4b(26)	October 15, 1984 (Exhibit 4(z), 1984 Form 10-K, File No. 1-3583).
4b(27)	October 15, 1984 (Exhibit 4(aa), 1984 Form 10-K, File No. 1-3583).
4b(28)	August 1, 1985 (Exhibit 4(dd), File No. 33-1689).
4b(29)	August 1, 1985 (Exhibit 4(ee), File No. 33-1689).
4b(30)	December 1, 1985 (Exhibit 4(c), File No. 33-1689).
4b(31)	March 1, 1986 (Exhibit 4b(31), 1986 Form 10-K, File No. 1-3583).
4b(32)	October 15, 1987 (Exhibit 4, September 30, 1987 Form 10-Q, File No. 1-3583).
4b(33)	September 15, 1988 (Exhibit 4b(33), 1988 Form 10-K, File No. 1-3583).
4b(34)	June 15, 1989 (Exhibit 4b(34), 1989 Form 10-K, File No. 1-3583).
4b(35)	October 15, 1989 (Exhibit 4b(35), 1989 Form 10-K, File No. 1-3583).
4b(36)	May 15, 1990 (Exhibit 4, June 30, 1990 Form 10-Q, File No. 1-3583).
4b(37)	March 1, 1991 (Exhibit 4(b), June 30, 1991 Form 10-Q, File No. 1-3583).
4b(38)	May 1, 1992 (Exhibit 4(a)(3), File No. 33-48844).
4b(39)	August 1, 1992 (Exhibit 4b(39), 1992 Form 10-K, File No. 1-3583).

Exhibit Number	Document
4b(40)	October 1, 1992 (Exhibit 4b(40), 1992 Form 10-K, File No. 1-3583).
4b(41)	January 1, 1993 (Exhibit 4b(41), 1992 Form 10-K, File No. 1-3583).
4b(42)	September 15, 1994 (Exhibit 4(b), September 30, 1994 Form 10-Q, File No. 1-3583).
4c	Open-End Subordinate Indenture of Mortgage between The Toledo Edison Company and Bank One, Columbus, N.A., as Trustee, Dated as of June 1, 1994 (Exhibit 4(b), August 26, 1994 Form 8-K, File No. 1-3583).
24 (TE)	*Powers of Attorney of Toledo Edison directors and officers required to sign the Report.
27 (TE)	*Financial Data Schedule for the period ended December 31, 1994.

Pursuant to Paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, the Registrants have not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of the applicable Registrant and its subsidiaries on a consolidated basis, but each hereby agrees to furnish to the Securities and Exchange Commission on request any such instruments.

Pursuant to Rule 14a-3(b)(10) under the Securities Exchange Act of 1934, copies of exhibits filed by the Registrants with this Form 10-K will be furnished by the Registrants to share owners upon written request and upon receipt in advance of the aggregate fee for preparation of such exhibits at a rate of $.25 per page, plus any postage or shipping expenses which would be incurred by the Registrants.