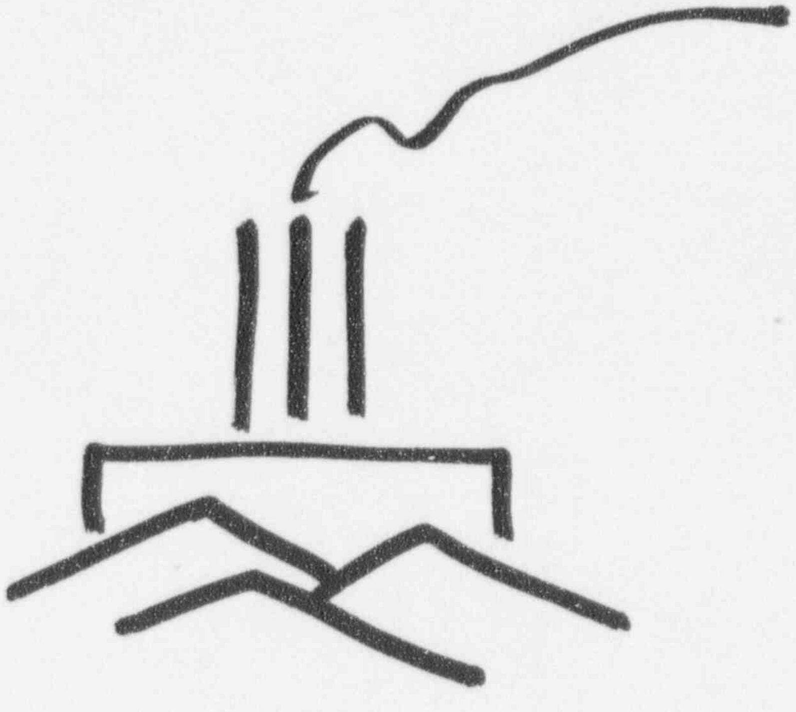
The Cleveland Electric Illuminating Company

A subsidiary of Centerior Energy Corporation



Annual Report 1994

Contents

About Cleveland Electric

The Company, a wholly owned subsidiary of Centerior Energy Corporation, provides electric service to an area of northeastern Ohio extending 100 miles along the southern shore of Lake Erie from Pennsylvania on the east through the city of Avon Lake on the west. The southern boundary of the service area is approximately 17 miles south of Lake Erie. The complete boundary prescribes an area of about 1,700 square miles. Total population served is about 1,830,000. Although the principal city in the service area is Cleveland, the Company derives about 77% of its total electric retail revenues from customers outside of the city. The Company's 3,547 employees serve about 747,000 customers.

Executive Offices

The Cleveland Electric Illuminating Company
55 Public Square
Cleveland, OH
(216) 622-9800

Mail Address

The Cleveland Electric Illuminating Company
P.O. Box 5000
Cleveland, OH 44101

Directors

Robert J. Farling, Chairman and Chief Executive Officer of the Company and The Toledo Edison Company and Chairman, President and Chief Executive Officer of Centerior Energy Corporation and Centerior Service Company.

Murray R. Edelman, President of the Company, Vice Chairman of The Toledo Edison Company and Executive Vice President of Centerior Energy Corporation and Centerior Service Company.

Fred J. Lange, Jr., Vice President of the Company, President of The Toledo Edison Company and Senior Vice President of Centerior Energy Corporation and Centerior Service Company.

Officers

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

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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.

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 part of this statement.

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

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	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)	$290
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	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		1993	
	Carrying Amount	Fair Value	Carrying Amount	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.

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 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 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.

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	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	19[illegible]	(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.

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	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

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	4 497	3 740	16.8%	62.4%	12 986	6 405	19 [illegible]	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.

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 Stock Series A, B, L and Depositary Shares, 1993 Series A, are listed on the New York 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 Cleveland Electric 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.

BONDHOLDER 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

The Cleveland Electric Illuminating Company
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Cleveland, OH 44101

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