1991 Annual Report

A Subsidiary of Centerior Energy Corporation

THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

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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 1,860,000. Although the principal city in the service area is Cleveland, the Company derives about 74% of its total electric revenue from customers outside of the city. The Company's 4,500 employees serve about 746,000 customers.

Executive Offices

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

Mail Address

P.O. Box 5000
Cleveland, OH 44101

Directors

Robert J. Farling,* President and Chief Operating Officer of Centerior Energy Corporation and Centerior Service Company.

Edgar H. Maugans,** Vice President and Chief Financial Officer of the Company and The Toledo Edison Company and Executive Vice President of Centerior Energy Corporation and Centerior Service Company.

Richard A. Miller,*** Chairman and Chief Executive Officer of Centerior Energy Corporation and Centerior Service Company.

Lyman C. Phillips, President and Chief Executive Officer of the Company, Chairman and Chief Executive Officer of The Toledo Edison Company and Executive Vice President of Centerior Energy Corporation and Centerior Service Company.

*Elected Chairman, President and Chief Executive Officer of Centerior Energy Corporation and Centerior Service Company effective March 1, 1992.

**Elected Director of the Company and The Toledo Edison Company effective March 1, 1992.

***Retired from these capacities effective March 1, 1992.

Officers

President and Chief Executive Officer	*Lyman C. Phillips*
Vice President & Chief Financial Officer	*Edgar H. Maugans*
Vice President	*Fred J. Lange, Jr.*
Controller	*Paul G. Busby*
Treasurer	*Gary M. Hawkinson*
Secretary	*E. Lyle Pepin*

To the Share Owners of
The Cleveland Electric Illuminating Company:

We have audited the accompanying consolidated balance sheet and consolidated statement of cumulative preferred stock of The Cleveland Electric Illuminating Company (a wholly owned subsidiary of Centerior Energy Corporation) and subsidiaries as of December 31, 1991 and 1990, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1991. 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, 1991 and 1990, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1991, in conformity with generally accepted accounting principles.

As discussed further in the Summary of Significant Accounting Policies and Note 12, a change was made in the method of accounting for nuclear plant depreciation in 1991, retroactive to January 1, 1991.

As discussed further in Note 3(c), the future of Perry Unit 2 is undecided. Construction has been suspended since July 1985. Various options are being considered, including resuming construction, converting the unit to a nonnuclear design, sale of all or part of the Company's ownership share, or canceling the unit. Management can give no assurance when, if ever, Perry Unit 2 will go in service or whether the Company's investment in that unit and a return thereon will ultimately be recovered.

Arthur Andersen & Co.

Cleveland, Ohio
February 14, 1992

Summary of Significant Accounting Policies

GENERAL

The Cleveland Electric Illuminating Company (Company) is an electric utility and a wholly owned subsidiary of Centerior Energy Corporation (Centerior Energy). The Company follows the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by The Public Utilities Commission of Ohio (PUCO). As a rate-regulated utility, the Company is subject to Statement of Financial Accounting Standards 71 which governs accounting for the effects of certain types of rate regulation. The financial statements include the accounts of the Company's wholly owned subsidiaries, which in the aggregate are not material.

The Company is a member of the Central Area Power Coordination Group (CAPCO). Other members include The Toledo Edison Company (Toledo Edison), Duquesne Light Company (Duquesne), Ohio Edison Company (Ohio Edison) and Ohio Edison's wholly owned subsidiary, Pennsylvania Power Company (Pennsylvania Power). The members have constructed and operate generation and transmission facilities for the use of the CAPCO companies. Toledo Edison is also a wholly owned subsidiary of Centerior Energy.

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 interchange power, transmission line rentals and jointly owned power plant operations and construction. See Notes 1 and 2.

Centerior Service Company (Service Company), the third wholly owned subsidiary of Centerior Energy, provides management, financial, administrative, engineering, legal and other services at cost to the Company and other affiliated companies. The Service Company billed the Company $138,000,000, $106,000,000 and $92,000,000 in 1991, 1990 and 1989, respectively, for such services.

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-hour sales rendered 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.

Operating revenues include certain wholesale power sales revenues in accordance with a FERC clarification of reporting requirements. Prior to 1991, these bulk power sales transactions were netted with purchased power transactions and reported as part of fuel and purchased power expense. The amounts for prior years have also been reclassified to conform with current reporting requirements. See Note 13.

FUEL EXPENSE

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

The 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.

PRE-PHASE-IN AND PHASE-IN DEFERRALS OF OPERATING EXPENSES AND CARRYING CHARGES

The PUCO authorized the Company to record, as deferred charges, certain operating expenses and carrying charges related to Perry Nuclear Power Plant Unit 1 (Perry Unit 1) and Beaver Valley Power Station Unit 2 (Beaver Valley Unit 2) from their respective in-service dates in 1987 through December 1988. Amortization and recovery of these deferrals (called pre-phase-in deferrals) began in January 1989 in accordance with the January 1989 PUCO rate order discussed in Note 6. The amortizations will continue over the lives of the related property.

As discussed in Note 6, the January 1989 PUCO rate order for the Company included an approved rate phase-in plan for the Company's investments in Perry Unit 1 and Beaver Valley Unit 2. On January 1, 1989, the Company began recording the deferrals of operating expenses and interest and equity carrying charges on deferred rate-based investment pursuant to the phase-in plan. These deferrals (called phase-in deferrals) will be recovered by December 31, 1998.

DEPRECIATION AND AMORTIZATION

The cost of property, plant and equipment is depreciated over their estimated useful lives on a straight-line basis. Prior to 1991, only nonnuclear property, plant and equipment was depreciated on a straight-line basis, as depreciation expense for the nuclear generating units was based on the units-of-production method.

The annual straight-line depreciation provision for nonnuclear property expressed as a percent of average depreciable utility plant in service was 3.4% in 1991, 3.3% in 1990 and 3.9% in 1989. The rate

declined in 1990 because of a PUCO-approved change in depreciation rates effective January 1, 1990, attributable to longer estimated lives for nonnuclear property. See Note 13.

In 1990, the Nuclear Regulatory Commission (NRC) approved a six-year extension of the operating license for the Davis-Besse Nuclear Power Station (Davis-Besse). The PUCO approved a change in the units-of-production depreciation rate for Davis-Besse, effective January 1, 1990, which recognized the life extension. See Note 13.

Effective January 1, 1991, the Company changed its method of accounting for nuclear plant depreciation from the units-of-production method to the straight-line method at about a 3% rate. The PUCO approved this change in accounting method for the Company and subsequently approved a change to lower the 3% rate to 2.5% for the three operating nuclear units retroactive to January 1, 1991. See Notes 12 and 13.

The Company uses external funding of future decommissioning costs for its operating nuclear units pursuant to a PUCO order. Cash contributions are made to the funds on a straight-line basis over the remaining licensing period for each unit. Amounts currently in rates are based on past estimates of decommissioning costs for the Company of $63,000,000 in 1986 dollars for Davis-Besse and $44,000,000 and $35,000,000 in 1987 dollars for Perry Unit 1 and Beaver Valley Unit 2, respectively. Actual decommissioning costs are expected to significantly exceed these estimates. It is expected that increases in the cost estimates will be recoverable in rates resulting from future rate proceedings. The current level of expense being funded and recovered from customers over the remaining licensing periods of the units is approximately $4,000,000 annually.

FEDERAL INCOME TAXES

The financial statements reflect the liability method of accounting for income taxes. The liability method requires that the Company's deferred tax liabilities be adjusted for subsequent tax rate changes and that the Company record deferred taxes for all temporary differences between the book and tax bases of assets and liabilities. A portion of these temporary differences are attributable to property-related timing differences that the PUCO used to reduce prior years' tax expense for ratemaking purposes whereby no deferred taxes were collected or recorded. Since the PUCO practice permits recovery of such taxes from customers when they become payable, the net amount due from customers has been recorded as a regulatory asset in deferred charges. A substantial portion of this amount relates to differences between the book and tax bases of utility plant. Hence, the recovery of these amounts will take place over the lives of the related assets.

Investment tax credits are deferred and amortized over the estimated lives of the applicable property. The amortization is reported as a reduction of depreciation expense under the liability method. See Note 7.

DEFERRED GAIN FROM SALE OF UTILITY PLANT

The Company entered into a sale and leaseback transaction in 1987 for the coal-fired Bruce Mansfield Generating Plant (Mansfield Plant) as discussed in Note 2. The transaction resulted in a net gain which was deferred. The Company is amortizing the applicable deferred gain over the term of leases under the sale and leaseback agreement. The amortization and the lease expense amount are recorded as other operation and maintenance expense.

INTEREST CHARGES

Debt interest reported in the Income Statement does not include interest on nuclear fuel obligations. Interest on nuclear fuel obligations for fuel under construction is capitalized. See Note 5.

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

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at original cost less any amounts ordered by the PUCO to be written off. Included in the cost of construction are items such as related payroll taxes, pensions, fringe benefits, management and general overheads and allowance for funds used during construction (AFUDC). AFUDC represents the estimated composite debt and equity cost of funds used to finance construction. This noncash allowance is credited to income, except for certain AFUDC for Perry Nuclear Power Plant Unit 2 (Perry Unit 2). See Note 3(c). The gross AFUDC rate was 10.47% in 1991, 10.48% in 1990 and 10.91% in 1989.

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

RECLASSIFICATIONS

Certain reclassifications have been made to prior years' financial statements to make them comparable with the 1991 financial statements and consistent with current reporting requirements. These include reclassifications related to certain wholesale power sales revenues as discussed previously under "Revenues" and accumulated deferred rents as discussed in Note 2.

RESULTS OF OPERATIONS

Overview

The January 1989 PUCO rate order for the Company, as discussed in Note 6, was designed to enable us to begin recovering in rates the cost of, and earn a fair return on, our allowed investment in Perry Unit 1 and Beaver Valley Unit 2. The rate order, which provided for three rate increases, improved revenues and cash flows in 1989, 1990 and 1991 from the 1988 levels. However, as discussed in the first four paragraphs of Note 6, the phase-in plan was not designed to improve earnings because gains in revenues from the higher rates and assumed sales growth are initially offset by a corresponding reduction in the deferral of nuclear plant operating expenses and carrying charges and are subsequently offset by the amortization of such deferrals.

Although the phase-in plan had a positive effect on revenues and cash flows, there are a number of factors that exerted a negative influence on earnings in 1991 and will continue to present significant earnings challenges in 1992 and beyond. One such factor is related to facilities placed in service after February 1988 and not included in rate base. The Company is required to record interest charges and depreciation on these facilities as current expenses even though such items are not yet recovered in rates. We also are facing the challenge of competitive forces, including new initiatives to create municipal electric systems. The need to meet competitive threats, coupled with a desire to encourage economic growth in the service area, is prompting the Company to enter into an increasing number of contracts having reduced rates with certain large customers. Factors beyond our control also having a negative influence on earnings are the economic recession, the effect of inflation and increases in taxes, other than federal income taxes.

The Company has taken several steps to counter the adverse effects of the factors discussed above. We have implemented most of the recommendations of the management audit discussed in Note 6 and have taken other actions which reduced other operation and maintenance expense by approximately $44,700,000 in 1991. As discussed in the Summary of Significant Accounting Policies and Note 12, we sought and received PUCO approval to lower our nuclear plant depreciation expense in 1991 to a level more closely aligned with the amount being recovered in rates. In addition, we have increased our efforts to sell power to other utilities which, in 1991, resulted in approximately $30,200,000 of revenues in excess of the cost of providing the power.

Despite the positive aspects of the measures discussed above, more must be done to maintain earnings. Continuing cost-reduction efforts will be necessary to lessen the negative pressures on earnings. The Company is aggressively seeking long-term power contracts with wholesale customers to further enhance revenues. To counter the effects of delays in recovering new investment since 1988 and related costs in rates, we have requested PUCO approval to accrue post-in-service carrying costs and defer depreciation for facilities that are in service but not yet recognized in rates. PUCO action on this request has been postponed under the joint recommendation approved by the PUCO discussed below.

In December 1991, the PUCO approved a joint recommendation of the Company, Toledo Edison and customer representative groups involved in the 1989 rate case settlement. The joint recommendation sought to secure an interim resolution of then-pending accounting applications in 1991 and to establish a framework for resolving accounting issues and related matters on a longer-term basis (i.e., 1992-1995). As part of this joint recommendation, the Company and Toledo Edison agreed to limit their combined 1992 other operation and maintenance expenses and capital expenditures to $1,050,000,000, exclusive of compliance costs related to the Clean Air Act Amendments of 1990 (Clean Air Act). Other operation and maintenance expenses and capital expenditures on a consolidated basis for Centerior Energy totaled $1,005,000,000 in 1991. The Company, Toledo Edison and the customer representative groups also agreed to an ongoing review of our business operations, financial condition and accounting practices. This effort, with the participation of the PUCO staff, is directed at the maintenance and ultimate improvement of our financial condition, the improvement of the efficiency of our operations, and the delay and minimization of future rate increases. The Company and Toledo Edison also agreed not to seek any base rate increase that would become effective before 1993.

The Company continually faces competitive threats from municipal electric systems within its service territory, a challenge intensified by municipal access to low-cost power currently available on the wholesale market. As part of our competitive strategy, we are strengthening programs that demonstrate the added value inherent in our service, beyond what one might receive from a municipal electric system. Such programs include providing services to communities to help them retain and attract businesses, providing consulting services to customers to improve their energy efficiency and developing demand-side management programs. To counter new municipalization initiatives, we are also stressing the financial risks and uncertainties of creating a municipal system and our superior reliability and service.

Annual sales growth is expected to average about 2% for the next several years, contingent on future economic events. Recognizing the limitations imposed by these sales projections and current competitive pressures, we will utilize our best efforts to minimize future rate increases through cost-reduction and quality-of-service efforts and exploring other innovative options. Eventually, rate increases will be necessary to recognize the cost of our new capital investment and the effect of inflation.

1991 vs. 1990

Factors contributing to the 8% increase in 1991 operating revenues are as follows:

Change in Operating Revenues	Increase
Base Rates and Miscellaneous	$ 74,000,000
Sales Volume and Mix	21,000,000
Wholesale Sales	40,000,000
	$135,000,000

The increases in base rates and miscellaneous revenues resulted primarily from the January 1989 PUCO rate order for the Company. The PUCO approved rate increases of 7% effective in February 1990 and 4.35% effective in February 1991. Total kilowatt-hour sales increased 4.3% in 1991. Residential and commercial sales increased 4.8% and 4.9%, respectively, as a result of higher usage of cooling equipment in response to the unusually warm late spring and summer 1991 temperatures. The commercial sales increase was also influenced by some improvement in the economy for the commercial sector. Industrial sales declined 6.3% largely because of the recession-driven slump in the steel, auto and chemical industries. Other sales increased 45.3% because of increased sales to wholesale customers and public authorities.

Operating expenses increased 4.9% in 1991. The increase was mitigated by a reduction of $44,700,000 in other operation and maintenance expense, resulting primarily from cost-cutting measures. Offsetting this decrease were an increase in fuel and purchased power expense resulting from increased purchased power costs and increased amortization of previously deferred fuel costs over the amount amortized in 1990; an increase in federal income taxes because of higher pretax operating income; an increase in taxes, other than federal income taxes, resulting from higher property and gross receipt taxes and accruals for Pennsylvania tax increases enacted in August 1991; and lower operating expense deferrals for Perry Unit 1 and Beaver Valley Unit 2 pursuant to the January 1989 PUCO rate order.

Credits for carrying charges recorded in nonoperating income decreased in 1991 because a greater share of our investments in Perry Unit 1 and Beaver Valley Unit 2 were recovered in rates. The federal income tax provision related to nonoperating income increased mainly because the 1990 provision was reduced by $18,712,000 for federal income tax adjustments associated with previously deferred investment tax credits relating to the 1988 write-off of nuclear plant.

1990 vs. 1989

Factors contributing to the 3.5% increase in 1990 operating revenues are as follows:

Change in Operating Revenues	Increase (Decrease)
Base Rates and Miscellaneous	$114,000,000
Sales Volume and Mix	(25,000,000)
Perry Unit 1 Capacity Sales to Ohio Edison and Pennsylvania Power	(32,000,000)
	$ 57,000,000

The major factor accounting for the increase in operating revenues was related to the January 1989 rate order. The PUCO approved rate increases for the Company of 9% effective in February 1989 and 7% effective in February 1990. The associated revenue increase in 1990 was partially offset by reduced revenues resulting from a 3.9% decrease in total kilowatt-hour sales. Industrial sales decreased 2.6% because of the recession beginning in 1990. Residential sales decreased 1.5% as seasonal temperatures were more moderate in comparison to the prior year's temperatures, resulting in reduced customer heating and cooling-related demand. Commercial sales increased 0.5% as increased demand from new all-electric office and retail space was offset by the effects of mild weather. Other sales activity decreased 21.4% primarily as a result of lower wholesale sales. The increase in revenues was also partially offset by the loss of revenues related to the May 1989 expiration of the Company's agreement to sell a portion of its share of Perry Unit 1 capacity to Ohio Edison and Pennsylvania Power.

Operating expenses decreased 0.3% in 1990. Depreciation and amortization expense decreased primarily because of lower depreciation rates used in 1990 for nonnuclear and Davis-Besse property attributable to longer estimated lives and because of longer nuclear generating unit refueling and maintenance outages in 1990 than in 1989. Federal income taxes decreased primarily because of a decrease in pretax operating income. Fuel and purchased power expense decreased primarily from less amortization of previously deferred fuel costs than the amount amortized in 1989. These decreases in operating expenses were partially offset by an increase in taxes, other than federal income taxes, resulting from higher property and gross receipts taxes, an increase in other operation and maintenance expense and by lower operating expense deferrals for Perry Unit 1 and Beaver Valley Unit 2.

Credits for carrying charges recorded in nonoperating income decreased in 1990 because a greater share of our investments in Perry Unit 1 and Beaver Valley Unit 2 were recovered in rates. The decrease in the federal income tax provision related to nonoperating income was the result of a decrease in pretax nonoperating income and federal income tax adjustments of $18,712,000 associated with previously deferred investment tax credits relating to the 1988 write-off of nuclear plant. Interest expense increased in 1990 because of the higher level of debt outstanding which was partially offset by refinancing.

EFFECT OF INFLATION

Although the rate of inflation has eased in recent years, we are still affected by even modest inflation since the regulatory process introduces a time-lag during which increased costs of our labor, materials and services are not reflected in rates and recovered. Moreover, regulation allows only the recovery of historical costs of plant assets through depreciation even though the costs to replace these assets would substantially exceed their historical costs in an inflationary economy.

Changes in fuel costs do not affect our results of operations since those costs are deferred until reflected in the fuel cost recovery factor included in customers' bills.

Income Statement

	For the years ended December 31,		
	1991	1990	1989
		(thousands of dollars)	
Operating Revenues	$1,825,738	$1,691,159	$1,634,227
Operating Expenses			
Fuel and purchased power (1)	455,055	412,397	427,108
Other operation and maintenance	469,530	514,186	508,151
Depreciation and amortization	170,571	169,526	187,614
Taxes, other than federal income taxes	215,908	197,454	183,120
Phase-in deferred operating expenses	(16,426)	(33,960)	(52,020)
Amortization of pre-phase-in deferred costs	9,586	10,076	9,553
Federal income taxes	105,824	75,099	85,275
	1,410,048	1,344,778	1,348,801
Operating Income	415,690	346,381	285,426
Nonoperating Income			
Allowance for equity funds used during construction	7,852	4,531	8,362
Other income and deductions, net	5,809	1,836	7,934
Phase-in carrying charges	87,615	161,598	216,851
Pre-phase-in carrying charges	—	—	17,937
Federal income taxes — credit (expense)	(24,311)	(20,401)	(55,699)
	76,965	147,564	195,385
Income Before Interest Charges	492,655	493,945	480,811
Interest Charges			
Debt interest	250,799	254,936	238,042
Allowance for borrowed funds used during construction	(4,302)	(3,319)	(7,450)
	246,497	251,617	230,592
Net Income	246,158	242,328	250,219
Preferred and Preference Dividend Requirements	35,857	36,682	40,227
Earnings Available for Common Stock	$ 210,301	$ 205,646	$ 209,992

(1) Includes purchased power expense of $127,691,000, $111,761,000 and $114,123,000 in 1991, 1990 and 1989, respectively, for purchases from Toledo Edison.

Retained Earnings

	For the years ended December 31,		
	1991	1990	1989
		(thousands of dollars)	
Balance at Beginning of Year	$ 563,559	$ 507,375	$ 459,709
Additions			
Net income	246,158	242,328	250,219
Deductions			
Dividends declared:			
Common stock	(194,306)	(149,199)	(161,662)
Preferred stock	(36,389)	(36,205)	(40,769)
Preference stock	—	—	(124)
Other, primarily preferred stock redemption expenses	(816)	(740)	2
Net Increase	14,647	56,184	47,666
Balance at End of Year	$ 578,206	$ 563,559	$ 507,375

The accompanying notes and summary of significant accounting policies are an integral part of these statements.

CAPITAL RESOURCES AND LIQUIDITY

In addition to our need for cash for normal corporate operations, we continue to need cash for an ongoing program of constructing new facilities and modifying existing facilities to meet anticipated demand for electric service, comply with governmental regulations and protect the environment. Cash is also needed for the mandatory retirement of securities. Over the three-year period of 1989-1991, these construction and mandatory retirement needs totaled approximately $800,000,000. In addition, we exercised various options to redeem and purchase approximately $270,000,000 of our securities.

As a result of the January 1989 PUCO rate order, internally generated cash increased in 1989, 1990 and 1991 from the 1988 level. In addition, we raised $1,049,000,000 through security issues and term bank loans during the 1989-1991 period as shown in the Cash Flows statement. During the three-year period, the Company also utilized its short-term borrowing arrangements (explained in Note 11) to help meet its cash needs. Proceeds from these financings were used to help pay for our construction program, to repay portions of short-term debt ir irred to finance the construction program, to retire, redeem and purchase outstanding securities, and for general corporate purposes.

Estimated cash requirements for 1992-1994 for the Company are $693,000,000 for its construction program and $464,000,000 for the mandatory redemption of debt and preferred stock. Additionally, the Company has arranged to refund in 1992 $78,700,000 principal amount of its First Mortgage Bonds, 13⅛% Series due 2012 by issuing an equal principal amount of first mortgage bonds due 2013 having an effective interest cost of 8.25%. We expect to finance externally about 50% of our total 1992 construction and mandatory redemption requirements of approximately $286,000,000. About 60-70% of the Company's 1993 and 1994 requirements are expected to be financed externally. If economical, additional securities may be redeemed under optional redemption provisions. See Notes 10(c) and (d) for information concerning limitations on the issuance of preferred and preference stock and debt.

Our capital requirements after 1994 will depend on the implementation strategy we choose to achieve compliance with the Clean Air Act. Expenditures for our optimal plan are estimated to be approximately $155,000,000 over the 1992-2001 period. See Note 3(b).

We expect to be able to raise cash as needed. The availability and cost of capital to meet our external financing needs, however, depends upon such factors as financial market conditions and our credit ratings. Current securities ratings for the Company are as follows:

	Standard & Poor's Corporation	Moody's Investors Service
First mortgage bonds	BBB–	Baa2
Preferred stock	BB+	baa2

A write-off of the Company's investment in Perry Unit 2, as discussed in Note 3(c), would not reduce retained earnings sufficiently to impair its ability to declare dividends and would not affect cash flow.

The Tax Reform Act of 1986 (1986 Tax Act) provided for a 34% income tax rate in 1988 and thereafter, a new alternative minimum tax (AMT) and other changes that resulted in increased tax payments and a reduction in cash flow during 198 1990 and 1991 because we were subject to the AM

	For the years ended December 31,		
	1991	1990	1989
	(thousands of dollars)		
Cash Flows from Operating Activities (1)			
Net Income	*$ 246,158*	$ 242,328	$ 250,219
Adjustments to Reconcile Net Income to Cash from Operating Activities:			
Depreciation and amortization	*170,571*	169,526	187,614
Deferred federal income taxes	*50,934*	111,029	108,261
Investment tax credits, net	*12,653*	(17,224)	(58)
Deferred and unbilled revenues	*(25,300)*	(38,134)	(32,168)
Deferred fuel	*13,450*	(11,410)	8,827
Carrying charges capitalized	*(87,615)*	(161,598)	(234,788)
Leased nuclear fuel amortization	*68,866*	47,028	55,712
Deferred operating expenses, net	*(6,840)*	(23,884)	(42,467)
Allowance for equity funds used during construction	*(7,852)*	(4,531)	(8,362)
Amortization of reserve for Davis-Besse refund obligations to customers	—	—	(12,162)
Pension settlement gain	—	(34,517)	—
Changes in amounts due from customers and others, net	*11,904*	(16,878)	(9,251)
Changes in inventories	*(15,040)*	(22,494)	(4,919)
Changes in accounts payable	*(23,667)*	31,901	(13,844)
Changes in working capital affecting operations	*36,997*	(5,195)	29,504
Other noncash items	*(13,334)*	(9,125)	(9,065)
Total Adjustments	*185,727*	14,494	22,834
Net Cash from Operating Activities	*431,885*	256,822	273,053
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	*(86,703)*	86,688	29
Notes payable to affiliates	*7,000*	(157,200)	90,200
Debt issues:			
First mortgage bonds	—	100,000	67,700
Secured medium-term notes	*150,000*	337,500	212,500
Term bank loans	—	16,000	40,000
Preferred stock issues	*125,000*	—	—
Maturities, redemptions and sinking funds	*(132,990)*	(211,810)	(305,741)
Nuclear fuel lease and trust obligations	*(63,895)*	(56,129)	(47,574)
Dividends paid	*(229,671)*	(185,851)	(202,444)
Premiums, discounts and expenses	*(5,990)*	(5,515)	(1,697)
Net Cash from Financing Activities	*(237,249)*	(76,317)	(147,027)
Cash Flows from Investing Activities (2)			
Cash applied to construction	*(137,851)*	(156,769)	(149,043)
Interest capitalized as allowance for borrowed funds used during construction	*(4,302)*	(3,319)	(7,450)
Loans to affiliates	*11,000*	(11,000)	—
Other cash received (applied)	*2,254*	(6,699)	(16,840)
Net Cash from Investing Activities	*(128,899)*	(177,787)	(173,333)
Net Change in Cash and Temporary Cash Investments	*65,737*	2,718	(47,307)
Cash and Temporary Cash Investments at Beginning of Year	*31,048*	28,330	75,637
Cash and Temporary Cash Investments at End of Year	*$ 96,785*	$ 31,048	$ 28,330

(1) Interest paid (net of amounts capitalized) was $221,000,000, $189,000,000 and $151,000,000 in 1991, 1990 and 1989, respectively. Income taxes paid were $49,536,000, $18,589,000 and $29,106,000 in 1991, 1990 and 1989, respectively.

(2) Increases in nuclear fuel and nuclear fuel lease and trust obligations in the Balance Sheet resulting from the noncash capitalizations under nuclear fuel agreements are excluded from this statement.

The accompanying notes and summary of significant accounting policies are an integral part of this statement.

	December 31,	
	19[illegible]	1990
	(thousands of dollars)	
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Utility plant in service	$6,195,945	$6,032,336
Less: accumulated depreciation and amortization	1,564,984	1,398,258
	4,630,961	4,634,078
Construction work in progress	161,890	175,232
Perry Unit 2	507,806	521,464
	5,300,657	5,330,774
Nuclear fuel, net of amortization	263,129	300,824
Other property, less accumulated depreciation	41,834	43,428
	5,605,620	5,675,026
CURRENT ASSETS		
Cash and temporary cash investments	96,785	31,048
Amounts due from customers and others, net	167,280	179,184
Amounts due from affiliates	3,648	19,542
Unbilled revenues	86,000	60,700
Materials and supplies, at average cost	89,043	76,092
Fossil fuel inventory, at average cost	39,089	37,000
Taxes applicable to succeeding years	167,753	155,069
Other	5,453	6,926
	655,051	565,561
DEFERRED CHARGES		
Amounts due from customers for future federal income taxes	673,726	671,450
Unamortized loss on reacquired debt	49,593	53,160
Carrying charges and operating expenses, pre-phase-in	368,448	377,324
Carrying charges and operating expenses, phase-in	568,472	464,434
Other	145,670	138,202
	1,805,909	1,704,570
Total Assets	$8,066,580	$7,945,157

The accompanying notes and summary of significant accounting policies are an integral part of this statement.

	December 31,	
	1991	1990
	(thousands of dollars)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common shares, without par value: 105,000,000 authorized; 79,591,000 outstanding in 1991 and 1990	*$1,240,570*	$1,242,074
Other paid-in capital	*78,625*	78,625
Retained earnings	*578,206*	563,559
Common stock equity	*1,897,401*	1,884,258
Preferred stock		
With mandatory redemption provisions	*268,368*	171,162
Without mandatory redemption provisions	*217,334*	217,334
Long-term debt	*2,682,805*	2,631,911
	5,065,908	4,904,665
OTHER NONCURRENT LIABILITIES		
Nuclear fuel lease obligations	*197,362*	246,460
Other	*33,391*	33,390
	230,753	279,[illegible]
CURRENT LIABILITIES		
Current portion of long-term debt and preferred stock	*92,857*	97,988
Current portion of lease obligations	*80,928*	64,554
Notes payable to banks and others	*191*	86,894
Accounts payable	*97,251*	120,918
Accounts and notes payable to affiliates	*58,578*	59,884
Accrued taxes	*281,526*	225,666
Accrued interest	*53,096*	53,113
Other	*34,499*	37,697
	698,926	746,714
DEFERRED CREDITS		
Unamortized investment tax credits	*258,318*	252,759
Accumulated deferred federal income taxes	*1,203,722*	1,159,199
Reserve for Perry Unit 2 allowance for funds used during construction	*124,398*	124,398
Unamortized gain from Bruce Mansfield Plant sale	*375,076*	389,658
Accumulated deferred rents for Bruce Mansfield Plant	*64,194*	57,045
Other	*45,285*	30,869
	2,070,993	2,013,928
Total Capitalization and Liabilities	*$8,066,580*	$7,945,157

Statement of Cumulative Preferred Stock

	1991 Shares Outstanding	Current Call Price	December 31, 1991	December 31, 1990
			(thousands of dollars)	
Without par value, 4,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$ 7.35 Series C	170,000	$ 101.00	*$ 17,000*	$ 18,000
88.00 Series E	27,000	1,030.61	*27,000*	30,000
75.00 Series F	—	—	—	2,384
145.00 Series I	—	—	—	13,779
113.50 Series K	—	—	—	10,000
Adjustable Series M	400,000	102.00	*39,200*	49,000
9.125 Series N	750,000	105.07	*73,968*	73,968
91.50 Series Q	75,000	—	*75,000*	—
88.00 Series R	50,000	—	*50,000*	—
			282,168	197,131
Less: Current maturities			*13,800*	25,969
Total Preferred Stock, with Mandatory Redemption Provisions			*$268,368*	$171,162
Not subject to mandatory redemption:				
$ 7.40 Series A	500,000	101.00	*$ 50,000*	$ 50,000
7.56 Series B	450,000	102.26	*45,071*	45,071
Adjustable Series L	500,000	103.00	*48,950*	48,950
Remarketed Series P	750	100,000.00	*73,313*	73,313
Total Preferred Stock, without Mandatory Redemption Provisions			*$217,334*	$217,334

The accompanying notes and summary of significant accounting policies are an integral part of this statement.

(1) 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 and operating costs. Each Lessor has leased its capacity rights to a utility which is obligated to pay for such Lessor's share of the construction and operating costs. The Company's share of the operating costs of these generating units is included in the Income Statement. Property, plant and equipment at December 31, 1991 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 and Suspended	Accumulated Depreciation
					(thousands of dollars)		
In Service:							
Seneca Pumped Storage	1970	80.00%	312	Hydro	$ 57,733	$ 1,021	$ 19,855
Eastlake Unit 5	1972	68.80	411	Coal	151,150	2,199	—
Davis-Besse	1977	51.38	454	Nuclear	680,121	21,055	150,911
Perry Unit 1 and Common Facilities	1987	31.11	371	Nuclear	1,622,823	4,201	191,227
Beaver Valley Unit 2 and Common Facilities (Note 2)	1987	24.47	201	Nuclear	1,170,046	5,461	143,750
Construction Suspended:							
Perry Unit 2 (Note 3(c))	Uncertain	31.11	375	Nuclear	—	507,806	—
					$3,681,873	$541,743	$505,743

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

Effective May 1, 1991, FERC approved an agreement under which the Company is selling the power from its share of the Seneca Power Plant to two subsidiaries of General Public Utilities Corporation through 1993. Revenues from this transaction were $16,000,000 in 1991.

Ohio Edison and Pennsylvania Power purchased 80 megawatts of the Company's capacity entitlement in Perry Unit 1 from November 1987 through May 1989. Revenues from this transaction were $31,831,000 in 1989.

The ownership share of Perry Unit 2 set forth above does not reflect the Company's acquisition of Duquesne's 13.74% ownership share in February 1992. See Note 3(c).

(2) UTILITY PLANT SALE AND LEASEBACK TRANSACTIONS

As a result of sale and leaseback transactions completed in 1987, 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.

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 payments have been made on behalf of Toledo Edison to date.

Future minimum lease payments under these operating leases at December 31, 1991 are summarized as follows:

Year	For the Company	For Toledo Edison
	(thousands of dollars)	
1992	$ 63,000	$ 110,000
1993	63,000	111,000
1994	63,000	111,000
1995	63,000	111,000
1996	63,000	111,000
Later Years	1,516,000	2,480,000
Total Future Minimum Lease Payments	$1,831,000	$3,034,000

Semiannual lease payments conform with the payment schedule for each lease.

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded by the Company in 1991, 1990 and 1989 as annual rental expense for the Mansfield Plant leases was $70,008,000. Amounts charged to expense in excess of the lease payments are now classified as accumulated deferred rents on the Balance Sheet. Previously, the excess was included in accounts payable.

The Company and Toledo Edison are responsible under these leases for paying all taxes, insurance premiums, operation and maintenance costs and all other similar costs for their interests in the units sold and leased back. The Company and Toledo Edison 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 to renew the leases. Additional lease provisions provide other purchase options along with conditions for mandatory termination of the leases (and possible repurchase of the leasehold interests) for events of default. These events of default include noncompliance with several financial covenants affecting the Company, Toledo Edison and Centerior Energy contained in an agreement relating to a letter

of credit issued in connection with the sale and leaseback of Beaver Valley Unit 2, as amended in 1989. See Note 10(d).

Toledo Edison is selling 150 megawatts of its Beaver Valley Unit 2 leased capacity entitlement to the Company. This sale commenced in 1988 and we anticipate that it will continue at least until 1998. Purchased power expense for this transaction was $106,589,000, $102,773,000 and $104,127,000 in 1991, 1990 and 1989, respectively. The future minimum lease payments associated with Beaver Valley Unit 2 aggregate $1,869,000,000.

(3) CONSTRUCTION AND CONTINGENCIES

(a) CONSTRUCTION PROGRAM

The estimated cost of the Company's construction program for the 1992-1994 period is $731,000,000, including AFUDC of $38,000,000 and excluding nuclear fuel.

In an agreement approved by the PUCO, the Company and Toledo Edison have agreed to limit their combined 1992 other operation and maintenance expenses and capital expenditures to $1,050,000,000, exclusive of compliance costs related to the Clean Air Act. Within this limitation, capital expenditures are budgeted at $191,000,000 for the Company, exclusive of the Clean Air Act compliance costs.

(b) CLEAN AIR LEGISLATION

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

Centerior Energy has developed a compliance strategy for the Company and Toledo Edison which will be submitted to the PUCO for review in April 1992. Centerior Energy will also seek United States Environmental Protection Agency approval of Phase I plans in 1993. The compliance plan which results in the least cost and the greatest flexibility provides for compliance with both phases through 2001 by greater use of low sulfur coal at some of our units and the banking of emission allowances. The plan would require capital expenditures for the Company over the 1992-2001 period of approximately $155,000,000 for nitrogen oxide control equipment, emission monitoring equipment and plant modifications. In addition, higher fuel and other operation and maintenance expenses would be incurred. The least cost plan also calls for the Company to place in service after 200[illegible] a scrubber or other sulfur emission reduction technology at one of its generating plants. The rate increase associated with the Company's capital expenditures and higher expenses would be about 1-2% in the late 1990s and another increase after the year 2000, for an aggregate rate increase in the range of 3-6%.

Our final compliance plan will depend upon future environmental regulations and input from the PUCO, other regulatory bodies and other concerned entities. If a plan other than the least cost plan is required, significantly higher capital expenditures could be required during the 1992-2001 period.

We believe that Ohio law permits the recovery of compliance costs from customers in rates.

(c) PERRY UNIT 2

Perry Unit 2, including its share of the common facilities, is approximately 50% complete. Construction of Perry Unit 2 was suspended in 1985 pending future consideration of various options, including resumption of full construction with a revised estimated cost, conversion to a nonnuclear design, sale of all or part of our ownership share, or cancellation. No option may be implemented without the unanimous approval of the owners. In October 1991, the Company, which is responsible for the construction of Perry Unit 2, applied for a ten-year extension of the construction permit which was to expire in November 1991. Under NRC regulations, the construction permit will remain in effect while the application is pending. We expect the NRC to grant the extension.

In February 1992, the Company purchased Duquesne's 13.74% ownership share of Perry Unit 2 for $3,324,000. This purchase increased the Company's ownership share of the unit to 44.85%, with the remainder owned by Toledo Edison, Ohio Edison and Pennsylvania Power. The purchase does not signal any plans to resume construction of Perry Unit 2, but rather our intent to keep our options open. Duquesne had stated that it would not agree to resumption of construction of the unit.

If Perry Unit 2 were to be canceled, then our net investment in the unit (less any tax saving) would have to be written off. The Company estimates that such a write-off, based on its investment in this unit as of December 31, 1991 and after adjustment for the February 1992 purchase of Duquesne's ownership share, would have been about $267,000,000, after taxes. See Note 10(d) for a discussion of potential consequences of such a write-off.

If a decision is made to convert Perry Unit 2 to a nonnuclear design in the future, we would expect to write-off at that time a portion of our investment for nuclear plant construction costs not transferable to the nonnuclear construction project.

Beginning in July 1985, Perry Unit 2 AFUDC was credited to a deferred income account until January 1, 1988, when the accrual of AFUDC was discontinued.

(d) SUPERFUND SITES

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended (Superfund) established programs addressing the cleanup of hazardous waste disposal sites, emergency preparedness and other issues. The Company is aware of its potential involvement in the cleanup of seven hazardous waste sites. The Company has recorded reserves based on estimates of its proportionate responsibility for these sites. We believe that the ultimate outcome of these matters will not have a material adverse effect on our financial condition or results of operations.

(4) NUCLEAR OPERATIONS AND CONTINGENCIES

(a) OPERATING NUCLEAR UNITS

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

(b) NUCLEAR INSURANCE

The Price-Anderson Act limits the liability of the owners of a nuclear power plant to the amount provided by private insurance and an industry assessment plan. In the event of a nuclear incident at any unit in the United States resulting in losses in excess of the level of private insurance (currently $200,000,000), the Company's maximum potential assessment under that plan (assuming the other CAPCO companies were to contribute their proportionate share of any assessment) would be $70,754,000 (plus any inflation adjustment) per incident, but is limited to $10,696,000 per year for each nuclear incident.

The CAPCO companies have insurance coverage for damage to property at the Davis-Besse, Perry and Beaver Valley sites (including leased fuel and clean-up costs). Coverage amounted to $2,515,000,000 for each site as of January 1, 1992. 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.

The Company also has extra expense insurance coverage which 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, 67% of such estimate per week for the next 52 weeks and 33% of such estimate per week for the next 52 weeks. The amount and duration of extra expense could substantially exceed the insurance coverage.

(5) NUCLEAR FUEL

The Company has inventories for nuclear fuel which should provide an adequate supply into the mid-1990s. Substantial additional nuclear fuel must be obtained to supply fuel for the remaining useful lives of Davis-Besse, Perry Unit 1 and Beaver Valley Unit 2. More nuclear fuel would be required if Perry Unit 2 were completed as a nuclear generating unit.

In 1989, existing nuclear fuel financing arrangements for the Company and Toledo Edison were refinanced through leases from a special-purpose corporation. The total amount of financing currently available under these lease arrangements is $509,000,000 ($309,000,000 from intermediate-term notes and $200,000,000 from bank credit arrangements), although financing in an amount up to $900,000,000 is permitted. The intermediate-term notes mature in the period 1993-1997. The bank credit arrangements are cancelable on two years notice by the lenders. As of December 31, 1991, $281,000,000 of nuclear fuel was financed for the Company. 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 of $76,000,000, $54,000,000 and $18,000,000, respectively, as of December 31, 1991. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $12,000,000 in 1991, $19,000,000 in 1990 and $25,000,000 in 1989. The estimated future lease amortization payments based on projected consumption are $51,000,000 in 1992, $54,000,000 in 1993, $51,000,000 in 1994, $44,000,000 in 1995 and $47,000,000 in 1996.

(6) REGULATORY MATTERS

On January 31, 1989, the PUCO issued a rate order which provided for three annual rate increases for the Company of approximately 9%, 7% and 6% effective with bills rendered on and after February 1, 1989, 1990 and 1991, respectively. As discussed below, the 6% increase effective February 1, 1991 was reduced to 4.35%. The resulting annualized revenue increases in 1989, 1990 and 1991 associated with the rate order were $120,700,000, $105,700,000 and $71,400,000, respectively.

Under the January 1989 rate order, a phase-in plan was designed so that the three rate increases, coupled with then-projected sales growth, would provide revenues sufficient to recover all operating expenses and provide a fair rate of return on the Company's allowed investment in Perry Unit 1 and Beaver Valley Unit 2 for ten years beginning January 1, 1989. In the first five years of the plan, the revenues were expected to be less than that required to recover operating expenses and provide a fair return on investment. Therefore, the amounts of operating

expenses and return on investment not currently recovered are deferred and capitalized as deferred charges. Since the unrecovered investment will decline over the period of the phase-in plan because of depreciation and deferred federal income taxes that result from the use of accelerated tax depreciation, the amount of revenues required to provide a fair return also declines. Pursuant to such phase-in plan, the Company deferred the following:

	1991	1990	1989
	(thousands of dollars)		
Deferred Operating Expenses	$ 16,426	$ 33,960	$ 52,020
Carrying Charges:			
Debt	$ 23,615	$ 51,421	$ 81,097
Equity	64,000	110,177	135,754
	$ 87,615	$161,598	$216,851

The amount of deferred operating expenses and carrying charges scheduled to be recorded in 1992 and 1993 total $51,000,000 and $16,000,000, respectively. Beginning in the sixth year (1994) and continuing through the tenth year, the revenue levels authorized pursuant to the phase-in plan were designed to be sufficient to recover that period's operating expenses, a fair return on the unrecovered investment, and the amortization of the deferred operating expenses and carrying charges recorded during the earlier years of the plan. All phase-in deferrals relating to these two units will be amortized and recovered by December 31, 1998.

The phase-in plan was also designed so that fluctuations in sales should not affect the level of earnings. The phase-in plan permits the Company to request PUCO approval of increases or decreases in the phase-in plan deferrals to compensate for the effects of fluctuations in sales levels, as compared to the levels projected in the rate order, and for 50% of the net after-tax savings in 1989 and 1990 identified by the management audit as discussed below. Pursuant to these provisions of the order, the Company recorded no adjustment to the cost deferrals in 1989 and recorded adjustments to increase the cost deferrals by approximately $24,000,000 and $24,500,000 in 1990 and 1991, respectively. The $24,500,000 increase recorded in 1991 included a $29,000,000 increase for the adjustment of the 1991 cost deferrals, which was partially offset by a $4,500,000 reduction for an adjustment of the 1990 cost deferrals.

In connection with the 1989 order and a similar order for Toledo Edison, the Company, Toledo Edison and the Service Company have undergone a management audit, which was completed in April 1990. The audit identified potential annual savings in operating expenses in the amount of $98,160,000 from Centerior Energy's 1989 budget level, 55% ($53,988,000) for the Company. The Company realized a large part of the savings in 1991.

Fifty percent of the savings identified by the management audit were used to reduce the 6% rate increase scheduled to be effective on February 1, 1991 for the Company. As discussed previously, our rates increased 4.35% under this provision with the PUCO's approval.

The 1989 order also set nuclear performance standards through 1998. We could be required to refund incremental replacement power costs if the standards are not met. No refund was required in 1991 nor is one expected for 1992. The Company banked $1,500,000 in benefits in 1991 for above-average nuclear performance based on industry standards for operating availability established in the 1989 order. These banked benefits are not recorded in the financial statements as they can only be used in future years, if necessary, to offset disallowances of incremental replacement power costs.

Under the 1989 order, fossil-fueled power plant performance may not be raised as an issue in any rate proceeding before February 1994 as long as the Company and Toledo Edison achieve a systemwide availability factor of at least 64.9% annually. This standard was exceeded in 1989, 1990 and 1991, with availability at approximately 80% for each year.

(7) FEDERAL INCOME TAX

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

	For the years ended December 31,		
	1991	1990	19[illegible]
		(thousands of dollars)	
Book Income Before Federal Income Ta	$376,293	$337,828	$391,193
Tax on Book Income at Statutory Rate	$127,940	$114,862	$133,006
Increase (Decrease) in Tax:			
Accelerated depreciation	(1,861)	7,140	4,422
Investment tax credits on disallowed nuclear plant	—	(18,712)	—
Taxes, other than federal income taxes	(1,680)	(9,469)	—
Other items	5,736	1,679	3,546
Total Federal Income Tax Expense	$130,135	$ 95,500	$140,974

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

	For the years ended December 31,		
	1991	1990	1989
		(thousands of dollars)	
Operating Expenses:			
Current Tax Provision	$ 74,552	$ 26,934	$ 63,447
Changes in Accumulated Deferred Federal Income Tax:			
... celerated depreciation and amortization	8,623	40,197	35,380
Alternative minimum tax credit	(2,550)	(18,860)	(34,874)
Sale and leaseback transaction and amortization	(8,838)	3,496	3,893
Property tax expense	—	(10,880)	—
Reacquired debt costs	15,729	1,887	(872)
Deferred construction work in progress revenues	(1,509)	12,093	11,005
Deferred fuel costs	(5,040)	4,763	(3,155)
Davis-Besse replacement power	—	—	4,136
Other items	13,615	14,980	6,257
Investment Tax Credits	11,242	1,489	58
Total Charged to Operating Expenses	105,824	75,099	85,275
Nonoperating Income:			
Current Tax Provision	(8,203)	(25,225)	(31,298)
Changes in Accumulated Deferred Federal Income Tax:			
Write-off of nuclear costs	(199)	(11,986)	—
AFUDC and carrying charges	31,769	57,612	87,541
Other items	944	—	(544)
Total Expense Charged to Nonoperating Income	24,311	20,401	55,699
Total Federal Income Tax Expense	$130,135	$ 95,500	$140,974

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.

Federal income tax expense adjustments in 1990, associated with previously deferred investment tax credits relating to the 1988 write-off of nuclear plant investments, decreased the net tax provision related to nonoperating income by $18,712,000.

The favorable resolution of an issue concerning the appropriate year to recognize a property tax deduction resulted in an adjustment which reduced federal income tax expense in 1990 by $10,100,000 ($8,207,000 in the fourth quarter).

For tax purposes, net operating loss (NOL) carryforwards of approximately $233,451,000 are available to reduce future taxable income and will expire in 2003 through 2005. The 34% tax effect of the NOLs generated is $79,373,000 and is reflected as a reduction to deferred federal income tax relating to accelerated depreciation and amortization. Future utilization of these tax NOL carryforwards would result in recording the related deferred taxes.

The 1986 Tax Act provides for an AMT credit to be used to reduce the regular tax to the AMT level should the regular tax exceed the AMT. AMT credits of $56,448,000 are available to offset future regular tax. The credits may be carried forward indefinitely.

(8) RETIREMENT INCOME PLAN AND OTHER POSTRETIREMENT BENEFITS

(a) RETIREMENT INCOME PLAN

The Company and Service Company jointly sponsor a noncontributing pension plan which covers all employee groups. The amount of retirement benefits generally depends upon the length of service. Under certain circumstances, benefits can begin as early as age 55. The plan also provides certain death, medical and disability benefits. The Company's and Service Company's funding policy is to comply with the Employee Retirement Income Security Act of 1974 guidelines.

In 1990, the Company and Service Company offered a Voluntary Early Retirement Opportunity Program (VEROP). Operating expenses for both companies for 1990 included $8,000,000 of pension plan accruals to cover enhanced VEROP benefits plus an additional $20,000,000 of pension costs for VEROP benefits paid to retirees from both companies' corporate funds. The $20,000,000 is not included in the pension data reported below. Operating expenses for 1990 for both companies also included a credit of $36,000,000 resulting from a settlement of pension obligations through lump sum payments to a substantial number of VEROP retirees.

Net pension and VEROP costs (credits) for 1989 through 1991 were comprised of the following components:

	1991	1990	1989
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 9	$ 10	$ 10
Interest cost on projected benefit obligation	25	26	25
Actual return on plan assets	(99)	3	(56)
Net amortization and deferral	50	(50)	9
Net pension credits	(15)	(11)	(12)
VEROP cost	—	8	—
Settlement gain	—	(36)	—
Net credits	$(15)	$(39)	$(12)

The following table presents a reconciliation of the funded status of the plan at December 31, 1991 and 1990.

	December 31,	
	1991	1990
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$ 209	$ 229
Nonvested benefits	23	18
Accumulated benefit obligation	232	247
Effect of future compensation levels	79	50
Total projected benefit obligation	311	297
Plan assets at fair market value	585	502
Surplus of plan assets over projected benefit obligation	274	205
Unrecognized net gain due to variance between assumptions and experience	(137)	(77)
Unrecognized prior service cost	8	8
Transition asset at January 1, 1987 being amortized over 19 years	(88)	(94)
Net prepaid pension cost	$ 57	$ 42

The settlement (discount) rate assumption was 8.5% for both December 31, 1991 and December 31, 1990. The long-term rate of annual compensation increase assumption was 5% for both December 31, 1991, and December 31, 1990. The long-term rate of return on plan assets assumption was 8.5% in 1991 and 8% in 1990.

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

(b) OTHER POSTRETIREMENT BENEFITS

The Financial Accounting Standards Board has issued a new accounting standard for postretirement benefits other than pensions. The new standard would require the accrual of the expected cost of such benefits during the employees' years of service. The assumptions and calculations involved in determining the accrual closely parallel pension accounting requirements.

The Company currently provides certain postretirement health care, death and other benefits and expenses such costs as these benefits are paid, which is consistent with current ratemaking practices. Such costs totaled $6,000,000 in 1991, $5,200,000 in 1990 and $4,200,000 in 1989, which include medical benefits of $4,900,000 in 1991, $4,100,000 in 1990 and $2,900,000 in 1989.

The Company expects to adopt the new standard prospectively effective January 1, 1993. We plan to amortize the discounted present value of the accumulated postretirement benefit obligation to expense over a twenty-year period. The Company has engaged actuaries who have made a preliminary review using 1990 data. Based on this preliminary review, the accumulated postretirement benefit obligation as of December 31, 1991, measured in accordance with the new standard, is estimated in the range of $80,000,000 to $115,000,000. Had the new standard been adopted in 1991, the preliminary study indicated that the additional postretirement benefit cost in 1991 would have been in the range of $7,500,000 to $13,500,000 (pretax). We believe the effect of actual adoption in 1993 may be similar, although it could be significantly different because of changes in health care costs, the assumed health care cost trend rate, work force demographics, interest rates, or plan provisions between now and 1993.

The Company does not know what action the PUCO may take with respect to these incremental costs. However, we believe the PUCO will either allow a means of current recovery of such incremental costs or provide for deferral of such costs until recovered in rates. We do not expect adoption of the new standard to have a material adverse effect on our financial condition or results of operations.

(9) GUARANTEES

Under two long-term coal purchase arrangements, the Company has guaranteed certain loan and lease obligations of two mining companies. One of these arrangements requires payments to the mining company for any actual out-of-pocket idle mine expenses (as advance payments for coal) when the

mines are idle for reasons beyond the control of the mining company. At December 31, 1991, after giving effect to a refinancing completed on January 2, 1992 by one of the mining companies, the principal amount of the mining companies' loan and lease obligations guaranteed by the Company was $78,000,000.

(10) CAPITALIZATION

(a) CAPITAL STOCK TRANSACTIONS

Preferred and preference stock shares sold and retired during the three years ended December 31, 1991 are listed in the following table.

	1991	1990	1989
	(thousands of shares)		
Cumulative Preferred and Preference Stock Subject to Mandatory Redemption:			
Preferred Sales:			
$ 91.50 Series Q	75	—	—
88.00 Series R	50	—	—
Preferred Retirements:			
$ 7.35 Series C	(10)	(10)	(10)
88.00 Series E	(3)	(3)	(3)
75.00 Series F	(2)	—	(1)
80.00 Series G	—	(1)	(2)
145.00 Series H	—	(14)	(4)
145.00 Series I	(14)	(4)	(4)
113.50 Series K	(10)	—	—
Adjustable Series M	(100)	—	—
Preference Retirements:			
$ 77.50 Series 1	—	—	(6)
Net Change	(14)	(32)	(30)

(b) EQUITY DISTRIBUTION RESTRICTIONS

At December 31, 1991, consolidated retained earnings were $578,206,000. The retained earnings were available for the declaration of dividends on the Company's preferred and common shares. All of the Company's common shares are held by Centerior Energy.

Any financing by the Company of any of its nonutility affiliates requires PUCO authorization unless the financing is made in connection with transactions in the ordinary course of the Company's public utilities business operations in which one company acts on behalf of another.

(c) CUMULATIVE PREFERRED AND PREFERENCE STOCK

Amounts to be paid for preferred stock which must be redeemed during the next five years are $14,000,000 in 1992, $29,000,000 in 1993, $29,000,000 in 1994, $40,000,000 in 1995 and $30,000,000 in 1996.

The annual mandatory redemption provisions are as follows:

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

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

The annualized cumulative preferred dividend requirement as of December 31, 1991 is $41,000,000.

The preferred dividend rates on the Company's Series L, M and P fluctuate based on prevailing interest rates and market conditions, with the dividend rates for these issues averaging 8.26%, 7.61% and 6.24%, respectively, in 1991.

Preference stock authorized for the Company is 3,000,000 shares without par value. No preference shares are currently outstanding.

There are no restrictions on the Company's ability to issue preferred or preference stock.

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	December 31, 1991	1990
		(thousands of dollars)	
First mortgage bonds:			
1992	15.25 %	$ —	$ 20,000
1992	10.58	—	40,000
1992	13.75	—	4,334
1993	3.875	30,000	30,000
1993	8.55	50,000	50,000
1993	13.75	4,334	4,334
1994	4.375	25,000	25,000
1994	13.75	4,334	4,334
1995	13.75	4,334	4,334
1995	7.00	750	750
1996	13.75	4,334	4,334
1996	7.00	750	750
1997-2001	11.20	61,420	61,420
2002-2006	9.27	140,076	140,076
2007-2011	8.66	335,350	335,350
2012-2016	8.97	439,085	439,085
2017-2021	8.59	567,880	567,880
2022-2023	7.78	174,300	174,300
		1,841,947	1,906,281
Term bank loans due 1993-1996	7.96	81,200	114,400
Medium-term notes due 1993-2021	9.17	700,000	550,000
Pollution control notes due 1993-2012	6.30	53,750	54,260
Other — net	—	5,908	6,970
Total Long-Term Debt		$2,682,805	$2,631,911

Long-term debt matures during the next five years as follows: $79,000,000 in 1992, $271,000,000 in 1993, $42,000,000 in 1994, $206,000,000 in 1995 and $151,000,000 in 1996.

During the 1989-1991 period, the Company issued $700,000,000 aggregate principal amount of secured medium-term notes. The notes are secured by first mortgage bonds.

The Company has arranged to refund in July 1992 $78,700,000 principal amount of a public authority's tax-exempt bonds due 2012 and having a 13⅛% interest rate with the proceeds from the sale in July

1992 of an equal principal amount of the authority's bonds due 2013 and having an effective interest cost of 8.25%. The Company's first mortgage bonds collaterally secure both issues. The PUCO authorized the Company to record interest expense equal to a blend of the higher rate on the outstanding bonds with the lower rate on the new bonds for an interest expense reduction of $1,000,000 in 1990, $3,000,000 in 1991 and approximately $3,000,000 in 1992.

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.

Additional first mortgage bonds may be issued by the Company under its mortgage on the basis of bondable property additions, cash or substitution for refundable first mortgage bonds. The issuance of additional first mortgage bonds on the basis of property additions is limited by two provisions of our mortgage. One relates to the amount of bondable property available and the other to earnings coverage of interest on the bonds. Under the more restrictive of these provisions (currently, the amount of bondable property available), we would have been permitted to issue approximately $335,000,000 of bonds based upon available bondable property at December 31, 1991. The Company also would have been permitted to issue approximately $214,000,000 of bonds based upon refundable bonds at December 31, 1991. If Perry Unit 2 had been canceled and written off as of December 31, 1991, the Company would not have been permitted to issue any bonds based upon available bondable property, but would have been permitted to issue approximately $214,000,000 of bonds based upon refundable bonds.

An agreement relating to a letter of credit issued in connection with the sale and leaseback of Beaver Valley Unit 2 (as amended in 1989) contains several financial covenants affecting the Company, Toledo Edison and Centerior Energy. Among these are covenants relating to earnings coverage ratios and capitalization ratios. The Company, Toledo Edison and Centerior Energy are in compliance with these covenant provisions. We believe these covenants can still be met in the event of a write-off of the Company's and Toledo Edison's investments in Perry Unit 2, barring unforeseen circumstances.

(11) SHORT-TERM BORROWING ARRANGEMENTS

The Company had $152,000,000 of bank lines of credit arrangements at December 31, 1991. This included a $30,000,000 line of credit which provided a $5,000,000 line of credit to be available to the Service Company if unused by the Company. There were no borrowings under these bank credit arrangements at December 31, 1991.

Short-term borrowing capacity authorized by the PUCO is $300,000,000 for the Company. The Company and Toledo Edison have been authorized by the PUCO to borrow from each other on a short-term basis.

Most borrowing arrangements under the short-term bank lines of credit require a fee of 0.25% per year to be paid on any unused portion of the lines of credit. For those banks without fee requirements, the average daily cash balance in the Company's bank accounts satisfied informal compensating balance arrangements.

At December 31, 1991, the Company had no commercial paper outstanding. If commercial paper were outstanding, it would be backed by at least an equal amount of unused bank lines of credit.

(12) CHANGES IN ACCOUNTING FOR NUCLEAR PLANT DEPRECIATION

In June 1991, the Company changed the method used to accrue nuclear plant depreciation from the units-of-production method to the straight-line method retroactive to January 1, 1991. The good performance of the nuclear generating units over the past several years had resulted in units-of-production depreciation expense being significantly higher than the amount implicit in current electric rates. The straight-line method better matches revenue and expense, tends to levelize periodic depreciation expense for nuclear plant and is more consistent with industry practice.

The PUCO approved the change and authorized the Company to accrue depreciation for its three operating nuclear generating units at an accrual rate of about 3% of plant investment based upon the units' forty-year operating licenses from the NRC. This change in method decreased 1991 depreciation expense $21,997,000 and increased 1991 net income $16,957,000 (net of $5,040,000 of income taxes) from what they otherwise would have been.

In December 1991, the PUCO approved a reduction in the straight-line depreciation accrual rate from about 3% to 2.5% for each of the three operating nuclear units retroactive to January 1, 1991. The Company believes the lower depreciation accrual rate is appropriate and reduces combined annual depreciation expense to a level more closely aligned with the total amount currently being recovered in customers' rates for these units. This change in rate decreased 1991 depreciation expense $18,309,000 and increased 1991 net income $14,006,000 (net of $4,303,000 of income taxes) from what they otherwise would have been.

Depreciation expense recorded in prior years was not affected. Current electric rates were also unaffected by the PUCO orders.

(13) QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

The following is a tabulation of the unaudited quarterly results of operations for the two years ended December 31, 1991.

	Quarters Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
	(thousands of dollars)			
1991				
Operating Revenues	$431,087	$455,614	$518,105	$420,932
Operating Income	90,340	102,283	139,400	83,667
Net Income	37,394	52,088	94,845	61,331
Earnings Available for Common Stock	29,197	43,402	85,874	51,828
1990				
Operating Revenues	$387,241	$405,150	$495,337	$403,431
Operating Income	76,273	57,599	130,348	82,161
Net Income	43,831	43,019	95,005	60,473
Earnings Available for Common Stock	34,280	33,682	86,043	51,641

Operating revenues for the first three quarters of 1991 and the four quarters of 1990 were restated to comply with current FERC revenue reporting requirements, as discussed in the Summary of Significant Accounting Policies. This restatement had no effect on earnings results for the applicable quarter. The unaudited quarterly results for the quarter ended March 31, 1991 were also restated to reflect the change in accounting for nuclear plant depreciation to the straight-line method (at about a 3% accrual rate) as discussed in Note 12.

Earnings for the quarter ended December 31, 1991 were increased as a result of year-end adjustments of $18,309,000 to reduce depreciation expense for the year for the change in the nuclear plant straight-line depreciation rate to 2.5% (see Summary of Significant Accounting Policies and Note 12) and $29,019,000 to increase phase-in carrying charges for the adjustment to 1991 cost deferrals (see Note 6). The total of these adjustments increased quarterly earnings by $33,159,000.

Earnings for the quarter ended June 30, 1990 were increased as a result of federal income tax expense adjustments associated with deferred investment tax credits relating to the 1988 write-off of nuclear plant investments. See Note 7. The adjustments increased quarterly earnings by $18,391,000.

Earnings for the quarter ended December 31, 1990 were increased as a result of year-end adjustments of $18,030,000 to reduce depreciation expense for the year for the change in depreciation rates for nonnuclear and Davis-Besse prope[illegible] see Summary of Significant Accounting Policies), $24,102,000 to increase phase-in carrying charges fo[illegible] adjustment to 1990 cost deferrals (see Note 6) and $8,207,000 to reduce federal income tax expense (see N[illegible]. The total of these adjustments increased quarterly earnings by $37,000,000.

Financial and Statistical Review

Operating Revenues (thousands of dollars)

Year	Residential	Commercial	Industrial	Other	Total Retail	Wholesale *(a)*	Total Electric	Steam Heating	Total Operating Revenues
1991	*$547 433*	*539 795*	*546 698*	*116 826*	*1 750 752*	*74 986*	*1 825 738*	*—*	*$1 825 738*
1990	495 158	494 370	543 813	122 701	1 656 042	35 117	1 691 159	—	1 691 159
1989	469 803	452 911	[illegible]19 854	117 220	1 559 788	74 439	1 634 227	—	1 634 227
1988	436 413	395 165	476 063	59 804	1 367 445	85 756	1 453 201	—	1 453 201
1987	428 786	389 297	470 861	12 322	1 301 266	13 416	1 314 682	13 371	1 328 053
1981	310 409	263 608	386 805	28 350	989 172	27 867	1 017 039	12 196	1 029 235

Operating Expenses (thousands of dollars)

Year	Fuel & Purchased Power *(a)*	Other Operation & Maintenance	Depreciation & Amortization	Taxes, Other Than FIT	Phase-in & Pre-phase-in Deferred, Net	Federal Income Taxes	Total Operating Expenses
1991	*$455 055*	*469 530*	*170 571 (b)*	*215 908*	*(6 840)*	*105 824*	*$1 410 048*
1990	412 397	514 186	169 526	197 [illegible]54	(23 884)	75 099	1 344 778
1989	427 108	508 151	187 614	[illegible]	(42 467)	85 275	1 348 801
1988	308 637	524 478	189 731	[illegible]	(104 396)	94 654	1 197 917
1987	334 328	425 938	148 918	146 [illegible]07	(47 826)	83 179	1 090 944
1981	367 715	224 299	85 294	91 648	—	67 575	836 531

Income (thousands of dollars)

Year	Operating Income	AFUDC—Equity	Other Income & Deductions, Net	Carrying Charge	Federal Income Taxes—Credit (Expense)	Income Before Interest Charges
1991	*$415 690*	*7 852*	*5 809*	*87 615*	*(24 311)*	*$492 655*
1990	346 381	4 531	1 836	161 598	(20 401)	493 945
1989	285 426	8 362	7 934	234 788	(55 690)	480 811
1988	255 284	8 052	(243 297) *(c)*	224 585	53 162	297 786
1987	237 109	177 170	(41 940)	24 610	79 606	476 555
1981	192 704	48 970	10 617	—	16 125	268 416

Income (thousands of dollars)

Year	Debt Interest	AFUDC—Debt	Income Before Cumulative Effect of an Accounting Change	Cumulative Effect of an Accounting Change	Net Income	Preferred & Preference Stock Dividends	Earnings Available for Common Stock
1991	*$250 799*	*(4 302)*	*246 158*	*—*	*246 158*	*35 857*	*$210 301*
1990	254 936	(3 3[illegible]9)	242 328	—	242 328	36 682	205 646
1989	238 042	(7 4[illegible]0)	250 219	—	250 219	40 227	209 992
1988	228 879	(4 3[illegible]4)	73 211	21 874 *(d)*	95 085	42 506	52 579
1987	249 958	(82 [illegible]85)	309 582	—	309 582	43 386	266 196
1981	146 712	(34 [illegible]30)	155 734	—	155 734	34 917	120 817

(a) Wholesale revenues, fuel and purchased power, wholesale electric sales and purchased power amounts are restated for 1990 and prior years to reflect a change in reporting of bulk power sales transactions in accordance with FERC requirements.

(b) 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.

(c) Includes write-off of nuclear costs in the amount of $257,400,000 in 1988.

(d) In 1988, a change in the method of accounting for unbilled revenues was adopted.

Year	Electric Sales (millions of KWH) Residential	Commercial	Industrial	Wholesale (a)	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
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	5 214	8 551	1 60[illegible]	46[illegible]	20 571	665 000	68 700	8 351	742 051	6 867	10.53	723.15
1989	4 789	5 208	8 780	2 132	501	21 410	660 786	68 030	8 329	737 145	7 025	9.81	691.83
1988	4 852	4 998	9 013	749	472	20 084	657 592	66 606	8 203	732 401	7 152	8.99	646.3[illegible]
1987	4 682	4 818	8 396	183	485	18 564	654 021	64 978	8 155	727 154	6 927	9.16	637.46
1981	4 376	4 178	8 [illegible]80	714	399	17 947	642 925	60 714	7 686	711 325	6 548	7.12	466.51

Year	Load (MW & %) Operable Capacity at Time of Peak	Peak Load	Capacity Margin	Load Factor	Energy (millions of KWH) Company Generated Fossil	Nuclear	Total	Purchased Power (a)	Total	Fuel Fuel Cost Per KWH	Efficiency— BTU Per KWH
1991	*4 695*	*3 886*	*17.2%*	*61.8%*	*13 193*	*7 [illegible]51*	*20 644*	*2 144*	*22 788*	*1.49¢*	*10 503*
1990	4 685	3 778	19.4	63.3	15 579	5 262	20 841	964	21 805	1.52	10 417
1989	4 536	3 866	14.8	65.2	14 968	6 570	21 538	1 268	22 806	1.49	10 506
1988	4 468 (e)	4 067	9.0	59.8	15 756	4 480	20 236	1 359	21 595	1.59	10 517
1987	4 257	3 722	12.6	62.5	14 978	3 689	18 667	1 376	20 043	1.5[illegible]	10 596
1981	4 667	3 447	26.1	62.7	15 225	2 255	17 480	1 781	19 261	1.85	10 [illegible]82

Investment (thousands 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
1991	*$6 195 945*	*1 564 984*	*4 630 961*	*669 696*	*304 963*	*$5 605 620*	*$150 005*	*$8 066 580*
1990	6 032 336	1 398 258	4 634 078	696 696	344 252	5 675 026	164 [illegible]	7 945 157
1989	5 869 283	1 258 905	4 610 378	726 933	354 374	5 691 685	143 [illegible]	7 670 405
1988	5 704 746	1 081 758	4 622 988	763 628	380 573	5 767 189	211 060	7 456 198
1987	5 787 603	905 297	4 882 306	633 433	389 281	5 905 020	566 947	7 089 026
1981	2 674 438	621 353	2 003 085	986 457	122 231 (f)	3 111 773	409 277	3 514 [illegible]57

Capitalization (thousands of dollars & %)

Year	Common Stock Equity		Preferred & Preference Stock, with Mandatory Redemption Provisions		Preferred Stock, without Mandatory Redemption Provisions		Long-Term Debt		Total
1991	*$1 897 401*	*38%*	*268 368*	*5%*	*217 334*	*4%*	*2 682 805*	*53%*	*$5 065 908*
1990	1 884 258	38	171 162	3	217 334	4	2 631 911	55	4 904 665
1989	1 828 074	40	212 362	4	217 334	5	2 336 379	51	4 594 149
1988	1 780 408	40	232 626	5	217 334	5	2 260 170	50	4 490 538
1987	1 925 719	41	270 645	6	217 334	4	2 [illegible]17 957	49	4 731 655
1981	1 002 206	36	325 000	12	95 071	4	1 328 404	48	2 750 681

(e) Capacity data reflects extended generating unit outage for renovation and improvements.

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

SHARE OWNER INFORMATION

INQUIRIES

Questions regarding the Company or stock accounts should be directed to Share Owner Services at Centerior Energy Corporation at the address and telephone numbers indicated below for the Stock Transfer Agent.

Please have your account [illegible] ready when calling.

STOCK TRANSFER AGENT

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

In Cleveland area 642-6900 or 447-2400
Outside Cleveland area 1-800-433-7794

Stock transfers may be presented at
PNC Trust Company of New York
40 Broad Street, Fifth Floor
New York, NY 10004

STOCK REGISTRAR

Ameritrust Company National Association
Corporate Trust Division
P.O. Box 6477
Cleveland, OH 44101

EXCHANGE LISTINGS

Preferred Stock Series A, B and L are listed on the New York Stock Exchange.

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN AND INDIVIDUAL RETIREMENT ACCOUNT (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 IRA may be obtained from Centerior Share Owner Services.

INDEPENDENT ACCOUNTANTS

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

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 the Secretary of Centerior Energy Corporation at the address of the Stock Transfer Agent.

BONDHOLDER INFORMATION

BOND TRUSTEE

Morgan Guaranty Trust Company of New York
Corporate Trust Administration
60 Wall Street
New York, NY 10260
Telephone Number (212) 235-0602

BOND PAYING AGENT

Inquiries regarding interest payments should be directed to either Manufacturers Hanover Trust Company or Morgan Guaranty Trust Company of New York for the series of bonds for which each acts as paying agent as noted below.

Co-paying agents for
$3\frac{7}{8}$% Series due 1993 $4\frac{3}{8}$% Series due 1994

Manufacturers Hanover Trust Company
40 Wall Street
New York, NY 10015

Ameritrust Company National Association
900 Euclid Avenue
Cleveland, OH 44114

Paying agent for all other series of bonds—

Morgan Guaranty Trust Company of New York
60 Wall Street
New York, NY 10260

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

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