THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

A Subsidiary of Centerior Energy Corporation

1992

ANNUAL REPORT

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 1,810,000. Although the principal city in the service area is Cleveland, the Company derives about 75% of its total electric revenue from customers outside of the city. The Company's 4,500 employees serve about 749,000 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, Chairman, President and Chief Executive Officer of Centerior Energy Corporation and Centerior Service Company.

Edgar H. Maugans, Vice President & Chief Financial Officer of the Company and The Toledo Edison Company and Executive Vice President 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.

Officers

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

Report of Independent Public Accountants

ARTHUR ANDERSEN &CO

To the Share Owners 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, 1992 and 1991, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1992. 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, 1992 and 1991, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1992, in conformity with generally accepted accounting principles.

As discussed further in the Summary of Significant Accounting Policies, 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 12, 1993

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 (SFAS) 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 their use. 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 firm power, 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 $150 million, $138 million and $106 million in 1992, 1991 and 1990, 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-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.

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.

DEFERRED CARRYING CHARGES AND OPERATING EXPENSES

As discussed in Note 6, the January 1989 PUCO rate order for the Company included an approved rate phase-in plan for its investments in Perry Nuclear Power Plant Unit 1 (Perry Unit 1) and Beaver Valley Power Station Unit 2 (Beaver Valley Unit 2). The plan called for the Company to begin deferring in January 1989 operating expenses and both interest and equity carrying charges on deferred rate-based investment. These deferrals, called phase-in deferrals, will be amortized and recovered by December 31, 1998. Previously, the PUCO authorized the Company to defer operating expenses and carrying charges for Perry Unit 1 and Beaver Valley Unit 2 from their respective in-service dates in 1987 through December 1988. The amortization and recovery of these deferrals, called pre-phase-in deferrals, also began in January 1989 and will continue over the lives of the related property.

Beginning in January 1992, the Company deferred charges for depreciation, property taxes and interest carrying charges related to plant placed in service after February 29, 1988 and not yet included in rate base. The PUCO authorized these deferrals in October 1992 under a Rate Stabilization Program. Similar deferrals may be recorded through December 31, 1995. Amortization and recovery of these deferrals will occur over the average life of the assets and will commence with future rate recognition. See Notes 6 and 13.

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 both 1992 and 1991 and 3.3% in 1990. Effective January 1, 1991, the Company, after obtaining PUCO approval, 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. This change decreased 1991 depreciation expense $22 million and increased 1991 net income $17 million (net of $5 million of income taxes) from what they otherwise would have been. The PUCO subsequently approved in 1991 a change to lower the 3% rate to 2.5% retroactive to January 1, 1991. See Note 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 trust funds on a straight-line basis over the remaining licensing period for each unit. The current level of expense being funded and recovered from customers over the remaining licensing periods of the

units is approximately $4 million annually. Amounts currently in rates are based on past estimates of decommissioning costs of $63 million in 1986 dollars for the Davis-Besse Nuclear Power Station (Davis-Besse) and $44 million and $35 million in 1987 dollars for Perry Unit 1 and Beaver Valley Unit 2, respectively. Actual decommissioning costs are expected to significantly exceed these estimates. We expect to complete our assessment of these estimates in 1993 to update the decommissioning cost amounts and to continue to satisfy the external funding requirements. It is expected that increases in the cost estimates will be recoverable in future rates. In the Balance Sheet at December 31, 1992, Accumulated Depreciation and Amortization included $32 million for the cumulative total of decommissioning costs previously expensed and the earnings on the external funding. This amount exceeds the Balance Sheet amount of the external Nuclear Plant Decommissioning Trusts because the reserve began prior to the external trust funding.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at original cost less any amounts ordered by the PUCO to be written off. Construction costs include related payroll taxes, pensions, fringe benefits, management and general overheads and allowance for funds used during construction (AFUDC). AFUDC represents the estimated composite debt and equity cost of funds used to finance construction. This noncash allowance is credited to income, except for certain AFUDC for Perry Nuclear Power Plant Unit 2 (Perry Unit 2). See Note 3(c). The AFUDC rate was 10.56% in 1992, 10.47% in 1991 and 10.48% in 1990.

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.

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 recorded as other operation and maintenance expenses. See Note 6.

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 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.

FEDERAL INCOME TAXES

The Financial Accounting Standards Board (FASB) issued a new standard for accounting for income taxes (SFAS 109) in February 1992. We adopted the new standard in 1992. The new standard amends certain provisions of SFAS 96 previously adopted in 1988. Adoption of the new standard in 1992 did not materially affect our results of operations, but did affect certain Balance Sheet accounts. See Note 7.

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

Investment tax credits are deferred and amortized over the estimated lives of the applicable property as a reduction of depreciation expense. See Note 6 for a discussion of the amortization of certain unrestricted excess deferred taxes and unrestricted investment tax credits available after 1998 under the Rate Stabilization Program.

RECLASSIFICATIONS

Certain reclassifications were made to prior years financial statements to make them comparable with the 1992 financial statements. A reserve for Perry Unit 2 AFUDC, which was previously reported under Deferred Credits in the Balance Sheet, was reclassified as an offset against the Perry Unit 2 asset balance. See Note 3(c).

Management's Financial Analysis

RESULTS OF OPERATIONS

Overview

In recent years, our efforts to add our substantial nuclear investment to rate base while maintaining a competitive rate structure have resulted in a series of agreements with the major intervenors in our rate cases. One agreement was approved by the PUCO in January 1989 and is described more fully in Note 6. It established our rate phase-in plan to recognize in rates our allowed investment in Perry Unit 1 and Beaver Valley Unit 2. The phase-in plan increased revenues and cash flows but was designed to have a relatively neutral impact on earnings. Gains in revenues were to be initially offset by a reduction in the deferral of operating expenses and carrying charges and subsequently offset by the amortization of such deferrals. A key assumption underlying the phase-in plan was that revenues would increase as a result of projected sales growth. When sales decreased primarily because of a sluggish economy, earnings were adversely affected.

A number of other factors also exerted a negative influence on earnings. These factors included the recording of nuclear plant depreciation at levels in excess of that reflected in rates, the recording of depreciation and interest charges on facilities placed in service after February 1988 as current expenses even though such items were not being recovered in rates and the effect of inflation on expenses. Also, the need to meet competitive forces, coupled with a desire to encourage economic growth in our service area, prompted us to reduce rates for certain industrial and commercial customers.

We determined that the best solution to address these factors was to delay rate increases and implement cost-reduction and revenue-enhancement strategies. Furthermore, we sought PUCO approval of regulatory accounting measures designed to recognize the effects of a delay in rate recovery of certain costs and provide a better match of current revenues and operating expenses. In 1991, we obtained PUCO approval to change the method and rate of accruing nuclear plant depreciation. In October 1992, the PUCO approved a Rate Stabilization Program, which was supported by certain customer representative groups, as discussed in Note 6. Under the terms of the Rate Stabilization Program, we agreed to freeze base rates until 1996 and to limit rate increases through 1998. In exchange, we are permitted to defer and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. However, our ability to utilize these regulatory accounting measures is dependent upon our taking significant actions to reduce costs and increase revenues. It is also dependent upon an ongoing determination that recovery of the deferred costs in rates is probable.

We face further challenges in the years to come. In 1994, expense deferrals provided in the 1989 agreement will cease. The amortization of the deferrals taken from 1989 through 1993 will also begin and continue through 1998. The amortization schedule provides for $23 million in 1994, increasing to $217 million in 1998. An additional $50 million of expense deferrals for 1990 and 1991, related to certain provisions of the phase-in plan, will be amortized and recovered by December 31, 1998. In addition, we are still confronted with competitive threats from municipal electric systems within our service territory and from cities contemplating creation of their own electric systems. 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.

To combat the forces described above, we have embarked on the following course. Reductions in other operation and maintenance expenses and capital expenditures were implemented in 1991 and 1992 and will be vigorously pursued in 1993 and beyond. We will further reduce staffing levels and look to improve efficiency of operations wherever possible. We are aggressively attempting to increase revenues by seeking additional long-term power sales agreements with wholesale customers and by exploring various corporate asset transactions. The Energy Policy Act of 1992 (Energy Act), which requires utilities to transmit electricity from wholesale suppliers to wholesale customers, will provide new opportunities for us to make wholesale power transactions. To counter municipal electric system initiatives, we have continued programs that demonstrate the value inherent in our service, beyond what one might expect from a municipal 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.

Increases in sales are expected to be modest with annual sales growth projected at about 1-2% for the next several years, depending upon the economic climate in our service area. Recognizing the fact that costs can be reduced only so far and the limitations imposed by our sales forecasts and competition in the wholesale power market, rate increases will be necessary eventually to recognize the cost of our new capital investment, including that being deferred under the Rate Stabilization Program, and inflation.

We believe that our Rate Stabilization Program and our strategies to reduce costs and increase revenues give us the opportunity to improve our com-

petitive position and our earnings. Nevertheless, we operate in a changing industry and market. We must monitor the impact of these changes on our strategy and the continued appropriateness of the regulatory accounting provided by our various agreements.

1992 vs. 1991

Factors contributing to the 4.5% decrease in 1992 operating revenues are as follows:

Decrease in Operating Revenues	*Millions of Dollars*
Sales Volume and Mix	$50
Base Rates and Miscellaneous	23
Fuel Cost Recovery Revenues	10
	$83

The revenue decreases resulted primarily from the different weather conditions in both years and the changes in the composition of the sales mix among customer categories. Weather accounted for approximately $55 million of the lower 1992 revenues. Winter and spring in 1992 were milder than in 1991. In addition, the 1992 summer was the coolest in 56 years in Northeastern Ohio as contrasted with the summer of 1991 which was much hotter than normal. As a result, total kilowatt-hour sales decreased 3.5% in 1992. Residential and commercial sales decreased 4.4% and 0.5%, respectively, as moderate temperatures in 1992 reduced electric heating and cooling demands. Industrial sales declined 0.4% as an 8.1% decrease in sales to the broad-based, smaller industrial customer group completely offset an 8.8% increase in sales to the larger industrial customer group. Sales to steel producers and auto manufacturers within the large industrial customer group rose 10.9% and 7%, respectively. Other sales decreased 16.1% because of decreased sales to wholesale customers and public authorities. The decrease in 1992 fuel cost recovery revenues resulted primarily because of the good performance of our generating units, which in turn decreased our fuel cost factors. The weighted averages of these factors decreased approximately 3%.

Operating expenses decreased 3.6% in 1992. Lower fuel and purchased power expense resulted from lower generation requirements stemming from less electric sales and less amortization of previously deferred fuel costs than the amount amortized in 1991. Federal income taxes decreased because of the Rate Stabilization Program's amortization of certain tax benefits and the effects of adopting SFAS 109 in 1992. These decreases were partially offset by higher depreciation and amortization, caused primarily by the adoption of SFAS 109, and by higher taxes, other than federal income taxes, caused by increased Ohio property and gross receipts taxes. Deferred operating expenses increased as a result of the deferrals under the Rate Stabilization Program as mentioned in Note 6.

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

1991 vs. 1990

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

Increase in Operating Revenues	*Millions of Dollars*
Base Rates and Miscellaneous	$ 74
Wholesale Sales	40
Sales Volume and Mix	21
	$135

The increases in base rates and miscellaneous revenues resulted primarily from rate increases in the January 1989 PUCO rate order for the Company as discussed in Note 6. 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 million in other operation and maintenance expenses, resulting primarily from cost-cutting measures. Offsetting this decrease were an increase in fuel and purchased power expense resulting primarily 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 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 for nonoperating income increased mainly because the 1990 provision was reduced $19 million for unamortized investment tax credits on the 1988 write-off of nuclear plant investments.

Income Statement

	For the years ended December 31,		
	1992	1991	1990
		(millions of dollars)	
Operating Revenues	$1,743	$1,826	$1,691
Operating Expenses			
Fuel and purchased power (1)	434	455	412
Other operation and maintenance	465	470	514
Total operation and maintenance	899	925	926
Depreciation and amortization	179	171	170
Taxes, other than federal income taxes	226	216	197
Deferred operating expenses, net	(35)	(7)	(24)
Federal income taxes	89	106	75
	1,358	1,411	1,344
Operating Income	385	415	347
Nonoperating Income			
Allowance for equity funds used during construction	1	8	5
Other income and deductions, net	8	6	1
Deferred carrying charges	59	88	162
Federal income taxes — credit (expense)	(5)	(24)	(20)
	63	78	148
Income Before Interest Charges	448	493	495
Interest Charges			
Debt interest	243	251	255
Allowance for borrowed funds used during construction	—	(4)	(3)
	243	247	252
Net Income	205	246	243
Preferred Dividend Requirements	41	36	37
Earnings Available for Common Stock	$ 164	$ 210	$ 206

(1) Includes purchased power expense of $130 million, $128 million and $112 million in 1992, 1991 and 1990, respectively, for all purchases from Toledo Edison.

Retained Earnings

	For the years ended December 31,		
	1992	1991	1990
		(millions of dollars)	
Balance at Beginning of Year	$ 578	$ 564	$ 507
Additions			
Net income	205	246	243
Deductions			
Dividends declared:			
Common stock	(195)	(194)	(149)
Preferred stock	(41)	(36)	(36)
Other, primarily preferred stock redemption expenses	(2)	(2)	(1)
Net Increase (Decrease)	(33)	14	57
Balance at End of Year	$ 545	$ 578	$ 564

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

Management's Financial Analysis

CAPITAL RESOURCES AND LIQUIDITY

We need cash for normal corporate operations, the mandatory retirement of securities and an ongoing program of constructing new facilities and modifying existing facilities. The construction program is needed to meet anticipated demand for electric service, comply with governmental regulations and protect the environment. Over the three-year period of 1990-1992, these construction and mandatory retirement needs totaled approximately $760 million. In addition, we exercised various options to redeem and purchase approximately $500 million of our securities.

We raised $1.2 billion through security issues and term bank loans during the 1990-1992 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. The Company had $21 million of short-term borrowings outstanding at December 31, 1992, including $11 million of notes payable to affiliates.

Estimated cash requirements for 1993-1995 for the Company are $658 million for its construction program and $627 million for the mandatory redemption of debt and preferred stock. The Company expects to finance externally about 85% of its total 1993 cash requirements of approximately $530 million. About 50-60% of the Company's 1994 and 1995 requirements are expected to be financed externally. If economical, additional securities may be redeemed under optional redemption provisions. See Note 10(d) for information concerning limitations on the issuance of debt.

Our capital requirements after 1995 will depend on our implementation strategy to achieve compliance with the Clean Air Act Amendments of 1990 (Clean Air Act). Expenditures for our optimal plan are estimated to be approximately $172 million over the 1993-2002 period. See Note 3(b).

The Company is aware of its potential involvement in the cleanup of seven hazardous waste sites. However, we believe that the ultimate outcome of these matters will not have a material adverse effect on our liquidity. See Note 3(d).

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. Apparently, the market perceives the Company as having a greater risk than its credit ratings would indicate. Therefore, in 1992, the Company had to offer interest and dividend rates on certain of its new debt and preferred stock securities which were significantly higher than those that would be expected for securities having the credit ratings of the Company. Current securities ratings for the Company are as follows:

	Standard & Poor's Corporation	*Moody's Investors Service*
First mortgage bonds	BBB−	Baa3
Unsecured notes	BB+	Ba1
Preferred stock	BB+	ba1

The ratings of Moody's Investors Service, Inc. set forth above reflect a downgrade in February 1993.

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.

Cash Flows

	For the years ended December 31,		
	1992	1991	1990
	(millions of dollars)		
Cash Flows from Operating Activities (1)			
Net Income	$ 205	$ 246	$ 243
Adjustments to Reconcile Net Income to Cash from Operating Activities:			
Depreciation and amortization	179	171	170
Deferred federal income taxes	66	51	111
Investment tax credits, net	(8)	13	(17)
Deferred and unbilled revenues	(7)	(25)	(38)
Deferred fuel	6	13	(11)
Deferred carrying charges	(59)	(88)	(162)
Leased nuclear fuel amortization	70	69	47
Deferred operating expenses, net	(35)	(7)	(24)
Allowance for equity funds used during construction	(1)	(8)	(5)
Pension settlement gain	—	—	(35)
Changes in amounts due from customers and others, net	6	12	(17)
Changes in inventories	(2)	(15)	(22)
Changes in accounts payable	7	(24)	32
Changes in working capital affecting operations	(4)	37	(5)
Other noncash items	(11)	(13)	(10)
Total Adjustments	207	186	14
Net Cash from Operating Activities	412	432	257
Cash Flows from Financing Activities (2)			
Bank loans, commercial paper and other short-term debt	10	(87)	87
Notes payable to affiliates	(13)	7	(157)
Debt issues:			
First mortgage bonds	324	—	100
Secured medium-term notes	90	150	338
Term bank loans	—	—	16
Preferred stock issues	74	125	—
Maturities, redemptions and sinking funds	(481)	(133)	(212)
Nuclear fuel lease obligations	(65)	(64)	(56)
Dividends paid	(235)	(230)	(186)
Premiums, discounts and expenses	(7)	(5)	(6)
Net Cash from Financing Activities	(303)	(237)	(76)
Cash Flows from Investing Activities (2)			
Cash applied to construction	(152)	(138)	(157)
Interest capitalized as allowance for borrowed funds used during construction	—	(4)	(3)
Loans to affiliates	—	11	(11)
Other cash received (applied)	(20)	2	(7)
Net Cash from Investing Activities	(172)	(129)	(178)
Net Change in Cash and Temporary Cash Investments	(63)	66	3
Cash and Temporary Cash Investments at Beginning of Year	97	31	28
Cash and Temporary Cash Investments at End of Year	$ 34	$ 97	$ 31

(1) Interest paid (net of amounts capitalized) was $205 million, $221 million and $189 million in 1992, 1991 and 1990, respectively. Income taxes paid were $28 million, $50 million and $19 million in 1992, 1991 and 1990, respectively.

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

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

Balance Sheet

	December 31, 1992	December 31, 1991
	(millions of dollars)	
ASSETS		
Property, Plant and Equipment		
Utility plant in service	$6,602	$6,196
Less: accumulated depreciation and amortization	1,728	1,565
	4,874	4,631
Construction work in progress	130	162
Perry Unit 2	371	383
	5,375	5,176
Nuclear fuel, net of amortization	224	263
Other property, less accumulated depreciation	37	42
	5,636	5,481
Current Assets		
Cash and temporary cash investments	34	97
Amounts due from customers and others, net	161	167
Amounts due from affiliates	10	4
Unbilled revenues	93	86
Materials and supplies, at average cost	90	89
Fossil fuel inventory, at average cost	40	39
Taxes applicable to succeeding years	176	168
Other	3	5
	607	655
Deferred Charges and Other Assets		
Amounts due from customers for future federal income taxes	583	674
Unamortized loss on reacquired debt	64	50
Carrying charges and operating expenses [illegible] nase-in	620	568
Carrying charges and operating expenses [illegible] ther	413	368
Nuclear plant decommissioning trusts	23	17
Other	177	129
	1,880	1,806
Total Assets	$8,123	$7,942

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

	December 31,	
	1992	1991
	(millions of dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shares, without par value: 105.0 million authorized; 79.6 million outstanding in 1992 and 1991	$1,241	$1,241
Other paid-in capital	79	79
Retained earnings	545	578
Common stock equity	1,865	1,898
Preferred stock		
With mandatory redemption provisions	314	268
Without mandatory redemption provisions	144	217
Long-term debt	2,515	2,683
	4,838	5,066
Other Noncurrent Liabilities		
Nuclear fuel lease obligations	177	197
Other	57	34
	234	231
Current Liabilities		
Current portion of long-term debt and preferred stock	310	93
Current portion of nuclear fuel lease obligations	67	81
Notes payable to banks and others	10	—
Accounts payable	104	97
Accounts and notes payable to affiliates	50	59
Accrued taxes	291	282
Accrued interest	55	53
Other	37	34
	924	699
Deferred Credits		
Unamortized investment tax credits	250	258
Accumulated deferred federal income taxes	1,392	1,204
Unamortized gain from Bruce Mansfield Plant sale	359	375
Accumulated deferred rents for Bruce Mansfield Plant	70	64
Other	56	45
	2,127	1,946
Total Capitalization and Liabilities	$8,123	$7,942

Statement of Preferred Stock

	1992 Shares Outstanding	Current Call Price Per Share	December 31, 1992	December 31, 1991
			(millions of dollars)	
Without par value, 4,000,000 preferred shares authorized				
Subject to mandatory redemption:				
$ 7.35 Series C	160,000	$ 101.00	$ 16	$ 17
88.00 Series E	24,000	1,026.78	24	27
Adjustable Series M	300,000	101.00	30	39
9.125 Series N	750,000	104.06	74	74
91.50 Series Q	75,000	—	75	75
88.00 Series R	50,000	—	50	50
90.00 Series S	75,000	—	74	—
			343	282
Less: Current maturities			29	14
Total Preferred Stock, with Mandatory Redemption Provisions			$314	$268
Not subject to mandatory redemption:				
$ 7.40 Series A	500,000	101.00	$ 50	$ 50
7.56 Series B	450,000	102.26	45	45
Adjustable Series L	500,000	103.00	49	49
Remarketed Series P	97	100,000.00	9	73
			153	217
Less: Current maturities			9	—
Total Preferred Stock, without Mandatory Redemption Provisions			$144	$217

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

Notes to the Financial Statements

(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, 1992 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
					(millions of dollars)		
In Service:							
Seneca Pumped Storage	1970	80.00%	351	Hydro	$ 62	$ 1	$ 20
Eastlake Unit 5	1972	68.80	411	Coal	155	1	—
Davis-Besse	1977	51.38	454	Nuclear	692	9	163
Perry Unit 1 and Common Facilities	1987	31.11	371	Nuclear	1,775	5	249
Beaver Valley Unit 2 and Common Facilities (Note 2)	1987	24.47	201	Nuclear	1,277	2	185
Construction Suspended:							
Perry Unit 2 (Note 3(c))	Uncertain	44.85	540	Nuclear	—	371	—
					$3,961	$389	$617

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

(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 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 include noncompliance with several financial covenants discussed in Note 10(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 payments have been made on behalf of Toledo Edison to date.

Future minimum lease payments under the operating leases at December 31, 1992 are summarized as follows:

Year	For the Company	For Toledo Edison
	(millions of dollars)	
1993	$ 63	$ 103
1994	63	103
1995	63	102
1996	63	125
1997	63	102
Later Years	1,453	2,123
Total Future Minimum Lease Payments	$1,768	$2,658

Rental expense is accrued on a straight-line basis over the terms of the leases. The amount recorded in 1992, 1991 and 1990 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. We anticipate that this purchase will

continue at least until 1998. Purchased power expense for this transaction was $108 million, $107 million and $103 million in 1992, 1991 and 1990, respectively. The future minimum lease payments associated with Beaver Valley Unit 2 aggregate $1.533 billion.

(3) *CONSTRUCTION AND CONTINGENCIES*

(a) CONSTRUCTION PROGRAM

The estimated cost of the Company's construction program for the 1993-1995 period is $697 million, including AFUDC of $39 million and excluding nucle. fuel.

(b) CLEAN AIR LEGISLATION

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

Centerior Energy developed a compliance strategy for the Company and Toledo Edison which was submitted to the PUCO in 1992 for review. Centerior Energy subsequently reached agreement with intervening parties and is awaiting formal PUCO approval. Centerior Energy also is seeking United States Environmental Protection Agency approval of the Phase 1 plans. The compliance plan which results in the least cost and the greatest flexibility provides for compliance with both phases through at least 2005. The plan calls for greater use of low-sulfur coal at some of our units and the banking of emission al vances. The plan would require capital expend .. es for the Company over the 1993-2002 period of approximately $172 million 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 a scrubber or other sulfur emission control technology in service at one of its generating plants sometime after 2004 with expenditures beginning in 2001. The anticipated rate increase associated with the Company's capital expenditures and higher expenses would be about 1-2% in the late 1990s. Another increase would be needed after the year 2000, for an aggregate rate increase in the range of 3-6%.

Our compliance plan will depend upon future environmental regulations and input from the PUCO, other regulatory bodies and other concerned entities. In addition, we are continuing to monitor developments in new technologies that may be incorporated into our compliance strategy. If a plan other than the least cost plan is required, significantly higher capital expenditures could be required during the 1993-2002 period. We believe 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. These options include 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. A request by the Company, which is responsible for the construction of Perry Unit 2, for an extension of the construction license is pending with the Nuclear Regulatory Commission (NRC).

In February 1992, the Company purchased Duquesne's 13.74% ownership share of Perry Unit 2 and all Perry real property for $3.3 million. This purchase increased the Company's ownership share of the unit to 44.85%. The remainc.r is owned by Toledo Edison, Ohio Edison and Pennsylvania Power.

The license extension request and the purchase of Duquesne's share do not indicate any plans to resume construction of Perry Unit 2. They were made to keep the Company's options open.

If Perry Unit 2 were canceled, the net-of-tax investment would have to be written off. Such a write-off (based on the Company's investment as of the end of 1992) would be about $263 million. Note 10(d) discusses more about the effects of a write-off.

If a decision were made to convert Perry Unit 2 to a nonnuclear design, we would expect to write off a portion of our investment for nuclear plant construction costs not transferable to the nonnuclear construction project.

Perry Unit 2 AFUDC was credited to a deferred income account from July 1985 until January 1, 1988, when the accrual was discontinued. The total deferred AFUDC amount of $124 million is reflected in the Balance Sheet as a reduction in the Perry Unit 2 investment.

(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 our control. Operating nuclear generating units have experienced unplanned outages or extensions of scheduled outages because of equipment problems or new regulatory requirements. A major accident at a nuclear facility anywhere in the world could cause the 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 treatment could include taking our affected unit out of rate base or disallowing certain construction or maintenance costs. An extended outage of one of our nuclear units coupled with unfavorable rate treatment could have a material adverse effect on our financial condition and results of operations.

(b) NUCLEAR INSURANCE

The Price-Anderson Act limits the liability of the owners of a nuclear power plant to the amount provided by private insurance and an industry assessment plan. In the event of a nuclear incident at any unit in the United States resulting in losses in excess of the level of private insurance (currently $200 million), the Company's maximum potential assessment under that plan would be $71 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 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 $2.625 billion for each site as of January 1, 1993. 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. It includes the incremental cost of any replacement power purchased (over the costs which would have been incurred had the units been operating) and other incidental expenses after the occurrence of certain types of accidents at our nuclear units. The amounts of the coverage are 100% of the estimated extra expense per week during the 52-week period starting 21 weeks after an accident and 67% of such estimate per week for the next 104 weeks. The amount and duration of extra expense could substantially exceed the insurance coverage.

(c) NUCLEAR DECONTAMINATION AND DECOMMISSIONING ASSESSMENT

The Energy Act permits special assessments on investor-owned electric utilities which own nuclear generating plants for the decontamination and decommissioning of nuclear enrichment facilities operated by the Department of Energy. The assessments to individual utilities are based upon the amount of enrichment services used in prior years and cannot be imposed for more than 15 years. At December 31, 1992, the Company accrued a liability of $19 million for its share of the total assessments. These costs are recorded as deferred charges since, based on the legislation, the Company believes the PUCO will allow the recovery of the assessments through the Company's fuel cost factors.

(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 its nuclear generating units.

Nuclear fuel is financed for the Company and Toledo Edison through leases with a special-purpose corporation. The total amount of financing currently available under these lease arrangements is $509 million ($309 million from intermediate-term notes and $200 million from bank credit arrangements). Financing in an amount up to $900 million is permitted. The intermediate-term notes mature in the period 1993-1997, with $77 million maturing in September 1993. The bank credit arrangements terminate in October 1993 at which time the corporation will obtain alternate financing. As of December 31, 1992, $246 million 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 for the Company of $46 million, $64 million and $23 million, respectively, as of December 31, 1992. The nuclear fuel amounts financed and capitalized also included interest charges incurred by the lessors amounting to $9 million in 1992, $12 million in 1991 and $19 million in 1990. The estimated future lease amortization payments based on projected consumption are $58 million in 1993, $59 million in

1994, $56 million in 1995, $54 million in 1996 and $50 million in 1997.

(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. The 6% increase effective February 1, 1991 was reduced to 4.35% as 50% of the savings identified by a management audit were used to reduce the rate increase. The resulting annualized revenue increases in 1990 and 1991 associated with the rate order were $106 million and $71 million, 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 over the ten years beginning January 1, 1989 sufficient to recover all operating expenses and provide a fair rate of return on the Company's allowed investments in Perry Unit 1 and Beaver Valley Unit 2. Revenues in the first five years of the plan 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. 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. Therefore, the amount of revenues required to provide a fair return also declines. This results in decreasing amounts of annual deferrals in the early years of the plan and then increasing amounts of amortization and recovery in the later years of the plan. The Company deferred $51 million, $104 million and $196 million in 1992, 1991 and 1990, respectively, of operating expenses and carrying charges pursuant to the phase-in plan. The amount of deferrals scheduled to be recorded in 1993 total $16 million. 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 investments, and the amortization of the deferred operating expenses and carrying charges recorded during the first five years of the plan. The phase-in deferrals relating to these two units will total $586 million after 1993 and are scheduled to be amortized and recovered as follows: $23 million in 1994, $66 million in 1995, $114 million in 1996, $166 million in 1997 and $217 million in 1998. Additional carrying charges totaling $50 million deferred for 1990 and 1991 pursuant to certain provisions of the phase-in plan will also be amortized and recovered by December 31, 1998. These amortizations can be accelerated at the option of the Company.

On October 22, 1992, the PUCO approved a Rate Stabilization Program as set forth in a joint recommendation filed by the Company, Toledo Edison and certain customer representative groups involved in the 1989 rate case settlement. Under the Rate Stabilization Program, the Company agreed to freeze base rates until 1996 and limit subsequent rate increases to no more than $93 million in 1996, $69 million in 1997 and $54 million in 1998. For purposes of any rate increase proceeding in the 1996-1998 period, the Company agreed to cap operation and maintenance expenses (other than fuel and purchased power) at $784 million on a consolidated basis for Centerior Energy, subject to adjustment for inflation and other specified expenses. During the 1996-1998 period, PUCO approval of any base rate increases and any additional regulatory accounting measures would be dependent upon our success in implementing cost-reduction and revenue-enhancement initiatives. The Company agreed to seek authorization for acceleration of the post-1998 Mansfield Plant unamortized gain in any rate increase proceeding in the 1996-1998 period. See Summary of Significant Accounting Policies.

As part of the Rate Stabilization Program, the Company is allowed to defer and subsequently recover certain costs not currently recovered in rates and to accelerate amortization of certain benefits. Such regulatory accounting measures provide for rate stabilization by rescheduling the timing of rate recovery of certain costs and the amortization of certain benefits, thereby preventing what otherwise would be an erosion in earnings during the 1992-1995 period. The continued use of these regulatory accounting measures during this period will be dependent upon a continuing assessment and determination that there will be probable recovery of such deferrals and carrying charges in future rates. The aggregate effect of these measures over this period could be as much as $316 million on an after-tax basis dependent upon the Company's success in implementing cost-reduction and other revenue-enhancement initiatives, among other factors. Such regulatory accounting measures which are eligible to be recorded through December 31, 1995 on an after-tax basis are as follows:

- Deferral of up to $227 million of accrued post-in-service interest carrying charges, depreciation expense and property taxes on assets placed in service after February 29, 1988. The deferrals recorded in 1992 were retroactive to January 1, 1992. Deferrals are based on actual capital expenditures relating to assets placed in service within the 1988-1995 period. Consequently, the deferrals will be lower than $227 million if the Company continues to reduce capital expenditures. Amortization and recovery of these defer-

rals will occur over the average life of the assets and will commence with future rate recognition.

- Acceleration of the amortizations of an estimated $57 million in unrestricted excess deferred taxes and $18 million in unrestricted investment tax credits available after 1998. The amortizations commenced October 1, 1992. The amortization of investment tax credits is reported as a reduction of depreciation expense.
- Amortization of up to $14 million in interim spent fuel storage accrual balances for Davis-Besse. The amortization commenced October 1, 1992.

The Company is also allowed to defer and subsequently recover the incremental expenses associated with adoption of the accounting standard for postretirement benefits other than pensions. See Note 8(b).

The Rate Stabilization Program provides for PUCO regulatory approval of certain corporate transactions, including major asset sales, after an evaluation of the customer benefit of these transactions. The Rate Stabilization Program may be renegotiated under certain force majeure and other events.

Deferred Operating Expenses, Net, and Deferred Carrying Charges shown in the Income Statement consist of the following:

	1992	1991	1990
	(millions of dollars)		
Deferred Operating Expenses, Net:			
Phase-in	$(11)	$(16)	$(34)
Rate Stabilization	(33)	—	—
Amortization of Pre-Phase-in Deferrals	9	9	10
Total	$(35)	$ (7)	$(24)
Deferred Carrying Charges:			
Phase-in:			
Debt	$ 15	$ 24	$ 52
Equity	25	64	110
Total Phase-in	40	88	162
Rate Stabilization (Debt)	19	—	—
Total	$ 59	$ 88	$162

(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:

	1992	1991	1990
	(millions of dollars)		
Book Income Before Federal Income Tax	$299	$376	$338
Tax on Book Income at Statutory Rate	$102	$128	$115
Increase (Decrease) in Tax:			
Depreciation	(3)	(2)	7
Investment tax credits on disallowed nuclear plant	—	—	(19)
Rate Stabilization	(5)	—	—
Taxes, other than federal income taxes	1	(2)	(9)
Other items	(1)	6	1
Total Federal Income Tax Expense	$ 94	$130	$ 95

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

	1992	1991	1990
	(millions of dollars)		
Operating Expenses:			
Current Tax Provision	$ 47	$ 75	$ 27
Changes in Accumulated Deferred Federal Income Tax:			
Accelerated depreciation and amortization	32	9	40
Alternative minimum tax credit	(18)	(3)	(19)
Sale and leaseback transactions and amortization	4	(9)	3
Property tax expense	14	—	(11)
Rate Stabilization	2	—	—
Reacquired debt costs	6	16	2
Deferred construction work in progress revenues	—	(2)	11
Deferred fuel costs	(2)	(5)	5
Other items	4	14	15
Investment Tax Credits	—	11	2
Total Charged to Operating Expenses	89	106	75
Nonoperating Income:			
Current Tax Provision	(19)	(8)	(25)
Changes in Accumulated Deferred Federal Income Tax:			
Write-off of nuclear costs	7	—	(12)
Rate Stabilization	6	—	—
AFUDC and carrying charges	14	32	57
Other items	(3)	—	—
Total Expense Charged to Nonoperating Income	5	24	20
Total Federal Income Tax Expense	$ 94	$130	$ 95

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.

In 1990, adjustments for unamortized investment tax credits on the 1988 write-off of nuclear plant investments decreased the federal income tax provision for nonoperating income $19 million. Also in 1990, the resolution of a property tax deduction issue resulted in a reduction in federal income tax expense of $10 million.

The adoption of SFAS 109 in 1992 affected certain Balance Sheet accounts. The most significant impact was an increase in Utility Plant In Service and an offsetting increase in Accumulated Deferred Federal Income Taxes.

Under SFAS 109, temporary differences and carryforwards gave rise to deferred tax assets of $415 million and deferred tax liabilities of $1.807 billion at December 31, 1992. These are summarized as follows:

	Millions of Dollars
Property, plant and equipment	$1,468
Deferred carrying charges and operating expenses	249
Sale and leaseback transactions	(123)
Net operating loss carryforwards	(79)
Investment tax credits	(132)
Other	9
Net deferred tax liability	$1,392

For tax purposes, net operating loss (NOL) carryforwards of approximately $234 million are available to reduce future taxable income and will expire in 2003 through 2005. The 34% tax effect of the NOLs is $79 million.

The Tax Reform Act of 1986 provides for an alternative minimum tax (AMT) credit to be used to reduce the regular tax to the AMT level should the regular tax exceed the AMT. AMT credits of $74 million are available to offset future regular tax. The credits may be carried forward indefinitely.

(8) RETIREMENT AND POSTEMPLOYMENT 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 funding policy of the Company and the Service Company 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 million of pension plan accruals to cover enhanced VEROP benefits and an additional $20 million of pension costs for VEROP benefits paid to retirees from corporate funds. The $20 million is not included in the pension data reported below. A credit of $36 million resulting from a settlement of pension obligations through lump sum payments to a substantial number of VEROP retirees partially offset the VEROP expenses for both companies.

Net pension and VEROP costs (credits) for 1990 through 1992 were comprised of the following components:

	1992	1991	1990
	(millions of dollars)		
Pension Costs (Credits):			
Service cost for benefits earned during the period	$ 10	$ 9	$ 10
Interest cost on projected benefit obligation	27	25	26
Actual return on plan assets	(19)	(99)	3
Net amortization and deferral	(35)	50	(50)
Net pension costs (credits)	(17)	(15)	(11)
VEROP cost	—	—	8
Settlement gain	—	—	(36)
Net costs (credits)	$(17)	$(15)	$(39)

The following table presents a reconciliation of the funded status of the plan at December 31, 1992 and 1991.

	December 31, 1992	December 31, 1991
	(millions of dollars)	
Actuarial present value of benefit obligations:		
Vested benefits	$ 215	$ 209
Nonvested benefits	28	23
Accumulated benefit obligation	243	232
Effect of future compensation levels	86	79
Total projected benefit obligation	329	311
Plan assets at fair market value	585	585
Surplus of plan assets over projected benefit obligation	256	274
Unrecognized net gain from variance between assumptions and experience	(107)	(137)
Unrecognized prior service cost	7	8
Transition asset at January 1, 1987 being amortized over 19 years	(82)	(88)
Net prepaid pension cost	$ 74	$ 57

At December 31, 1992 and 1991, the settlement (discount) rate and long-term rate of return on plan assets assumptions were 8.5% and the long-term rate of annual compensation increase assumption was 5%.

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

(b) OTHER POSTRETIREMENT BENEFITS

The FASB accounting standard for postretirement benefits other than pensions (SFAS 106) requires 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 $5 million in 1992, $6

million in 1991 and $5 million in 1990, which included medical benefits of $4 million in 1992, $5 million in 1991 and $4 million in 1990.

The Company will adopt the standard effective January 1, 1993. The Company plans to amortize the present value of the accumulated postretirement benefit obligation to expense over a 20-year period. Based on our actuaries' review of 1992 data, the accumulated postretirement benefit obligation as of December 31, 1992 is estimated to be in the range of $110 million to $140 million (pretax). Had the standard been adopted in 1992, the additional 1992 postretirement benefit cost would have been in the range of $10 million to $14 million (pretax). The Company believes the 1993 effect of actual adoption 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, plan provisions or interest rates. Like the retirement income plan, these estimates reflect a discount rate assumption of 8.5% per year. The annual health care cost trend assumption is 12% in 1992, reducing gradually to an ultimate annual rate of 6% in 1996 and later years.

The PUCO authorized the Company to defer for subsequent recovery postretirement benefit costs that exceed its actual payments for the period 1993-1997. This provision was part of the Rate Stabilization Program discussed in Note 6. The amount we can defer will be determined by the extent to which Centerior Energy is successful in reducing the added obligation on a consolidated basis by $37 million or 25% of the incremental costs expected when the Company got the order. The Company and Centerior Energy have until December 31, 1997 to make the reductions.

(c) POSTEMPLOYMENT BENEFITS

In November 1992, the FASB issued a new accounting standard for postemployment benefits (SFAS 112), such as severance pay, disability, worker's compensation and supplemental unemployment benefits. The Company is required to adopt the new standard no later than 1994. We have not completed an analysis to determine the effect of adopting the new standard.

(9) GUARANTEES

The Company has guaranteed certain loan and lease obligations of two mining companies under two long-term coal purchase arrangements. 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, 1992, the principal amount of the mining companies' loan and lease obligations guaranteed by the Company was $71 million.

(10) CAPITALIZATION

(a) CAPITAL STOCK TRANSACTIONS

Preferred stock shares sold and retired during the three years ended December 31, 1992 are listed in the following table.

	1992	1991	1990
	(thousands of shares)		
Subject to Mandatory Redemption:			
Sales			
$ 91.50 Series Q	—	75	—
88.00 Series R	—	50	—
90.00 Series S	75	—	—
Retirements			
$ 7.35 Series C	(10)	(10)	(10)
88.00 Series E	(3)	(3)	(3)
75.00 Series F	—	(2)	—
80.00 Series G	—	—	(1)
145.00 Series H	—	—	(14)
145.00 Series I	—	(14)	(4)
113.50 Series K	—	(10)	—
Adjustable Series M	(100)	(100)	—
Not Subject to Mandatory Redemption:			
Retirements			
Remarketed Series P	(1)	—	—
Net Change	(39)	(14)	(32)

(b) EQUITY DISTRIBUTION RESTRICTIONS

At December 31, 1992, consolidated retained earnings were $545 million. 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) PREFERRED AND PREFERENCE STOCK

Amounts to be paid for preferred stock which must be redeemed during the next five years are $38 million in 1993, $29 million in 1994, $40 million in 1995 and $30 million in both 1996 and 1997.

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.

The Company has called for redemption the remaining 97 outstanding shares of its Serial Pre-

ferred Stock, Remarketed Series P, in August 1993 at a redemption price of $100,000 per share.

The annualized preferred dividend requirement as of December 31, 1992 was $42 million.

The preferred dividend rates on the Company's Series L, M and P fluctuate based on prevailing interest rates and market conditions. The dividend rates for these issues averaged 7.59%, 7.04% and 6.73%, respectively, in 1992.

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 at December 31, 1992*	*December 31, 1992*	*December 31, 1991*
		(millions of dollars)	
First mortgage bonds:			
1993	3.875%	$ —	$ 30
1993	8.55	—	50
1993	13.75	—	4
1994	4.375	25	25
1994	13.75	4	4
1995	13.75	4	4
1995	7.00	1	1
1996	13.75	4	4
1996	7.00	1	1
1997	10.88	6	6
1997	13.75	4	4
1997	7.00	1	1
1998-2002	8.31	306	61
2003-2007	8.92	127	132
2008-2012	8.20	310	410
2013-2017	8.90	538	663
2018-2022	7.84	337	337
2023	5.85	104	104
		1,772	1,841
Term bank loans due 1994-1996	7.31	8	81
Medium-term notes due 1994-2021	8.95	678	700
Pollution control notes due 1994-2012	6.31	53	54
Other — net	—	4	7
Total Long-Term Debt		$2,515	$2,683

Long-term debt matures during the next five years as follows: $272 million in 1993, $42 million in 1994, $206 million in 1995, $151 million in 1996 and $55 million in 1997.

The Company issued $578 million aggregate principal amount of secured medium-term notes during the 1990-1992 period. The notes are secured by first mortgage bonds. At December 31, 1992, the Company had $35 million aggregate principal amount of secured medium-term notes registered with the Securities and Exchange Commission and available for issuance.

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), the Company would have been permitted to issue approximately $329 million of bonds based upon available bondable property at December 31, 1992. The Company also would have been permitted to issue approximately $432 million of bonds based upon refundable bonds at December 31, 1992. If Perry Unit 2 had been canceled and written off as of December 31, 1992, the Company would not have been permitted to issue any bonds based upon available bondable property, but would have been permitted to issue approximately $432 million 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 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 convenants 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 $137 million of bank lines of credit arrangements at December 31, 1992. This included a $30 million line of credit which provided a $5 million 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, 1992.

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.

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 balances.

At December 31, 1992, the Company had $10 million of short-term notes outstanding under an uncommitted financing facility. The Company can borrow up to $40 million until the agreement is canceled by either party.

At December 31, 1992, 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) *FINANCIAL INSTRUMENTS' FAIR VALUE*

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

	Carrying Amount	*Fair Value*
	(millions of dollars)	
Nuclear Plant Decommissioning Trusts	$ 23	$ 24
Preferred Stock, with Mandatory Redemption Provisions (including current portion)	343	342
Long-Term Debt (including current portion)	2,793	2,886

The fair value of the nuclear plant decommissioning trusts is estimated based on the quoted market prices for the investment securities. The fair value of the 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, 1992 because of their short-term nature.

(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, 1992.

	Quarters Ended			
	March 31,	*June 30,*	*Sept. 30,*	*Dec. 31,*
	(millions of dollars)			
1992				
Operating Revenues	$422	$415	$479	$427
Operating Income	83	85	139	77
Net Income	27	33	102	43
Earnings Available for Common Stock	17	23	92	32
1991				
Operating Revenues	$431	$456	$518	$421
Operating Income	90	102	139	84
Net Income	38	52	95	61
Earnings Available for Common Stock	29	43	86	52

Earnings for the quarter ended September 30, 1992 were increased by $26 million as a result of the recording of deferred operating expenses and carrying charges for the first nine months of 1992 totaling $39 million under the Rate Stabilization Program approved by the PUCO in October 1992. See Note 6.

Earnings for the quarter ended December 31, 1991 were increased by $33 million as a result of year-end adjustments of $18 million 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 $29 million to increase phase-in carrying charges for an adjustment to 1991 cost deferrals (see Note 6).

Financial and Statistical Review

Operating Revenues (millions of dollars)

Year	Residential	Commercial	Industrial	Other	Total Retail	Wholesale	Total Electric	Steam Heating	Total Operating Revenues
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
1989	470	453	520	117	1 560	74	1 634	—	1 634
1988	436	395	476	60	1 367	86	1 453	—	1 453
1982	349	305	394	35	1 083	17	1 100	18	1 118

Operating Expenses (millions of dollars)

Year	Fuel & Purchased Power	Other Operation & Maintenance	Depreciation & Amortization	Taxes, Other Than FIT	Deferred Operating Expenses, Net	Federal Income Taxes	Total Operating Expenses
1992	$434	465	179	226	(35)	89	$1 358
1991	455	470	171(a)	216	(7)	106	1 411
1990	412	514	170	197	(24)	75	1 344
1989	427	508	188	183	(42)	85	1 349
1988	308	524	190	185	(104)	95	1 198
1982	339	250	87	107	—	106	889

Income (millions of dollars)

Year	Operating Income	AFUDC—Equity	Other Income & Deductions, Net	Deferred Carrying Charges	Federal Income Taxes—Credit (Expense)	Income Before Interest Charges
1992	$385	1	8	59	(5)	$448
1991	415	8	6	88	(24)	493
1990	347	5	1	162	(20)	495
1989	285	8	9	235	(56)	481
1988	255	8	(243)(b)	225	53	298
1982	229	77	(2)	—	22	326

Income (millions 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
1992	$243	—	205	—	205	41	$164
1991	251	(4)	246	—	246	36	210
1990	255	(3)	243	—	243	37	206
1989	238	(7)	250	—	250	40	210
1988	229	(4)	73	22(c)	95	42	53
1982	144	(27)	209	—	209	38	171

(a) 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.

(b) Includes write-off of nuclear costs in the amount of $257 million in 1988.

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

Electric Sales (millions of KWH) / Electric Customers (year end) / Residential Usage

Year	Electric Sales: Residential	Commercial	Industrial	Wholesale	Other	Total	Electric Customers: Residential	Commercial	Industrial & Other	Total	Residential Usage: Average KWH Per Customer	Average Price Per KWH	Average Revenue Per Customer
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
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	646.35
1982	4 336	4 194	7 082	687	414	16 713	641 705	61 861	7 656	711 222	6 490	8.08	524.63

Load (MW & %) / Energy (millions of KWH) / Fuel

Year	Operable Capacity at Time of Peak	Peak Load	Capacity Margin	Load Factor	Company Generated: Fossil	Nuclear	Total	Purchased Power	Total	Fuel Cost Per KWH	Efficiency—BTU Per KWH
1992	4 703	3 605	23.3%	63.0%	12 715	7 521	20 236	1 649	21 885	1.47¢	10 456
1991	4 695	3 886	17.2	61.8	13 193	7 451	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(d)	4 067	9.0	59.8	15 756	4 480	20 236	1 359	21 595	1.59	10 517
1982	4 699	3 090	34.2	65.3	15 576	1 650	17 226	766	17 992	1.83	10 475

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
1992	$6 602	1 728	4 874	501	261	$5 636	$156	$8 123
1991	6 196	[illegible]	4 631	545	305	5 481	150	7 942
1990	6 032	1 398	4 634	572	344	5 550	165	7 821
1989	5 869	1 259	4 610	603	354	5 567	144	7 546
1988	5 705	1 082	4 623	639	381	5 643	211	7 332
1982	2 725	680	2 045	1 286	158(e)	3 489	422	3 974

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
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
1989	1 828	40	212	4	217	5	2 336	51	4 593
1988	1 780	40	233	5	217	5	2 260	50	4 490
1982	1 227	40	322	10	95	3	1 442	47	3 086

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

(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
PNC Trust Company of New York
40 Broad Street, Fifth 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) 447-2682.

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 (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 & Co.
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

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

BOND PAYING AGENT

Inquiries regarding interest payments should be directed to either Chemical Bank for the 4⅜% Series due 1994 or Morgan Guaranty Trust Company of New York for all other series of bonds.

Chemical Bank
Bondholder Relations
450 W. 33rd Street, 8th Floor
New York NY 10001
1-800-648-8380

Morgan Guaranty Trust Company of New York
Securityholder Relations
60 Wall Street
New York NY 10260
(212) 235-0602

The Cleveland Electric Illuminating Company
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Cleveland OH 44101

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