Indiana Michigan
Power Company
Cook Nuclear Plant
500 Circle Drive
Buchanan, MI 49107
616-465-5901

INDIANA
MICHIGAN
POWER

May 25, 2000

C0500-12
10 CFR 50.71
10 CFR 140.21

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop O-P1-17
Washington, D.C. 20555-0001

Donald C. Cook Nuclear Plant Units 1 and 2
1999 FINANCIAL INFORMATION FOR
INDIANA MICHIGAN POWER COMPANY

Indiana Michigan Power Company (I&M) hereby submits, as attachment 1, the 1999 Annual Financial Report in accordance with 10 CFR 50.71(b). Also included as attachment 2 is a copy of the year 2000 projected cash flow for I&M as required by 10 CFR 140.21(e).

Should you have any questions, please contact Mr. Robert C. Godley, Director of Regulatory Affairs, at (616) 466-2698.

Sincerely,

M. W. Marano
Business Services Director

/dms

Attachment

c: J. E. Dyer
MDEQ – DW & RPD, w/o attachment
NRC Resident Inspector
R. Whale, w/o attachment

M004

ATTACHMENT 1 TO C0500-12

INDIANA MICHIGAN POWER COMPANY
1999 ANNUAL REPORT

Indiana Michigan Power Company

1999 Annual Report

AEP AMERICAN® ELECTRIC POWER

AEP: America's Energy Partner℠

INVESTOR INQUIRIES
Investors should direct inquiries to Investor Relations using the toll free number 1-800-237-2667 or by writing to:
Bette Jo Rozsa
Managing Director of Investor Relations
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT
The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 2000 at no cost to shareholders. Please address requests for copies to:
Geoffrey C. Dean
Director of Financial Reporting Division
American Electric Power Service Corporation
26th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

TRANSFER AGENT AND REGISTRAR OF CUMULATIVE PREFERRED STOCK
Equiserve, First Chicago Division
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CONTENTS

BACKGROUND

INDIANA MICHIGAN POWER COMPANY (the Company) is engaged in the generation, purchase, transmission and distribution of electric power. The Company serves approximately 559,000 retail customers in northern and eastern Indiana and a portion of southwestern Michigan and sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives and non-utility entities engaged in the wholesale power market. Approximately 84% of the Company's retail sales are in Indiana and 16% in Michigan. The principal industries served are primary metals, electrical and electronic machinery, transportation equipment, chemicals and allied products, fabricated metal products and rubber and miscellaneous plastic products.

The Company, which was organized under the laws of Indiana on February 21, 1925, is a subsidiary of American Electric Power Company, Inc., a public utility holding company. The Company does business as American Electric Power (AEP) along with all of the parent's operating subsidiary companies in order to serve its customers more efficiently as one operating organization aligned by distinct business units. The Company's two wholly-owned subsidiaries, Blackhawk Coal Company and Price River Coal Company, were formerly engaged in coal-mining operations in Utah. Blackhawk Coal Company currently leases or subleases portions of its coal rights, land and related mining equipment to unaffiliated companies. In addition, the Company has a river transportation division (RTD) that barges coal on the Ohio and Kanawha Rivers to AEP System generating plants. The RTD also provides some barging services to unaffiliated companies.

The Company owns and leases 4,435 megawatts (mw) of generating capacity which includes 2,295 mw of coal-fired generation and 2,110 mw of nuclear generation. The Company owns the two unit Donald C. Cook Nuclear Plant located in Michigan. The generating plants and transmission facilities of the Company and certain other affiliated AEP System utility subsidiaries are operated as an integrated system with their costs and benefits shared through the AEP System Power Pool and AEP Transmission Equalization Agreement. Wholesale energy sales made by the AEP Power Pool are allocated to the Company and the other AEP Power Pool members. The other AEP Power Pool members are: Appalachian Power Company, Columbus Southern Power Company, Kentucky Power Company and Ohio Power Company. The Company is interconnected with two other affiliated companies, Kingsport Power Company and Wheeling Power Company that are not members of the AEP Power Pool, and with numerous unaffiliated utilities through the AEP System. In addition, the Company is also directly interconnected with its affiliate, AEP Generating Company, and the following unaffiliated entities: Central Illinois Public Service Company, The Cincinnati Gas & Electric Company, Commonwealth Edison Company, Consumers Energy Corporation, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, PSI Energy Inc. and Richmond Power and Light Company, as well as Indiana-Kentucky Electric Corporation (a subsidiary of Ohio Valley Electric Corporation, an affiliate that is not a member of the AEP System).

DIRECTORS

Karl G. Boyd	Henry W. Fayne	Armando A. Pena
Coulter R. Boyle, III (a)	James A. Kobyra (d)	John R. Sampson (f)
Gregory A. Clark (b)	William J. Lhota	David B. Synowiec
E. Linn Draper, Jr.	Mark W. Marano (e)	Joseph H. Vipperman
Jeffrey A. Drozda (c)	James J. Markowsky	William E. Walter
		Earl H. Wittkamper

OFFICERS

E. Linn Draper, Jr.
Chairman of the Board and Chief Executive Officer

William J. Lhota
President and Chief Operating Officer

A. Christopher Bakken III (g)
Site Vice President, Donald C. Cook Plant

Coulter R. Boyle, III (h)
Vice President

Henry W. Fayne
Vice President

James J. Markowsky
Vice President

Armando A. Pena
Vice President, Treasurer and Chief Financial Officer

Robert P. Powers
Vice President

Michael W. Rencheck
Vice President - Nuclear Engineering

John R. Sampson
Vice President

Joseph H. Vipperman
Vice President

Leonard V. Assante
Controller and Chief Accounting Officer

John F. DiLorenzo, Jr.
Secretary

Elio Bafile
Assistant Controller and Assistant Secretary

Timothy P. Bowman
Assistant Controller

William L. Scott
Assistant Controller

Thomas G. Berkemeyer
Assistant Secretary

Maurice C. McIntyre (b)
Assistant Secretary

John B. Shinnock
Assistant Secretary

Bruce M. Barber
Assistant Treasurer

Christopher J. Keklak
Assistant Treasurer

As of January 1, 2000 the current directors and officers of Indiana Michigan Power Company were employees of American Electric Power Service Corporation with nine exceptions: Messrs. Bakken, Boyd, Drozda, Marano, Rencheck, Sampson, Synowiec, Walters and Wittkamper, who were employees of Indiana Michigan Power Company.

(a) Resigned May 26, 1999
(b) Resigned October 25, 1999
(c) Elected May 26, 1999
(d) Resigned July 27, 1999
(e) Elected July 27, 1999
(f) Elected October 25, 1999
(g) Elected March 25, 1999
(h) Resigned February 1, 1999

SELECTED CONSOLIDATED FINANCIAL DATA

	Year Ended December 31,				
	1999	1998	1997	1996	1995
			(in thousands)		
INCOME STATEMENTS DATA:					
Operating Revenues	$1,394,119	$1,405,794	$1,339,232	$1,328,493	$1,283,157
Operating Expenses	1,285,467	1,239,787	1,131,444	1,108,076	1,077,434
Operating Income	108,652	166,007	207,788	220,417	205,723
Nonoperating Income (Loss)	4,530	(839)	4,415	2,729	6,272
Income Before Interest Charges	113,182	165,168	212,203	223,146	211,995
Interest Charges	80,406	68,540	65,463	65,993	70,903
Net Income	32,776	96,628	146,740	157,153	141,092
Preferred Stock Dividend Requirements	4,885	4,824	5,736	10,681	11,791
Earnings Applicable to Common Stock	$ 27,891	$ 91,804	$ 141,004	$ 146,472	$ 129,301

	December 31,				
	1999	1998	1997	1996	1995
			(in thousands)		
BALANCE SHEETS DATA:					
Electric Utility Plant	$4,770,027	$4,631,848	$4,514,497	$4,377,669	$4,319,564
Accumulated Depreciation and Amortization	2,194,397	2,081,355	1,973,937	1,861,893	1,751,965
Net Electric Utility Plant	$2,575,630	$2,550,493	$2,540,560	$2,515,776	$2,567,599
Total Assets	$4,576,696	$4,148,523	$3,967,798	$3,897,484	$3,928,337
Common Stock and Paid-in Capital	$ 789,323	$ 789,189	$ 789,056	$ 787,856	$ 787,686
Retained Earnings	166,389	253,154	278,814	269,071	235,107
Total Common Shareholder's Equity	$ 955,712	$1,042,343	$1,067,870	$1,056,927	$1,022,793
Cumulative Preferred Stock:					
Not Subject to Mandatory Redemption	$ 9,248	$ 9,273	$ 9,435	$ 21,977	$ 52,000
Subject to Mandatory Redemption (a)	64,945	68,445	68,445	135,000	135,000
Total Cumulative Preferred Stock	$ 74,193	$ 77,718	$ 77,880	$ 156,977	$ 187,000
Long-term Debt (a)	$1,324,326	$1,175,789	$1,049,237	$1,042,104	$1,040,101
Obligations Under Capital Leases (a)	$ 187,965	$ 186,427	$ 195,227	$ 130,965	$ 142,506
Total Capitalization and Liabilities	$4,576,696	$4,148,523	$3,967,798	$3,897,484	$3,928,337

(a) Including portion due within one year.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

This discussion includes forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. These forward-looking statements reflect assumptions, and involve a number of risks and uncertainties. Among the factors that could cause actual results to differ materially from forward looking statements are: electric load and customer growth; abnormal weather conditions; available sources and costs of fuels; availability of generating capacity; the speed and degree to which competition is introduced to the power generation business, the structure and timing of a competitive market and its impact on energy prices or fixed rates; the ability to recover regulatory assets and other stranded costs in connection with deregulation of generation; new legislation and government regulations; the ability of the Company to successfully control its costs; the economic climate and growth in our service territory; unforeseen events affecting the Company's efforts to restart its nuclear generating units which are on an extended safety related shutdown; the outcome of litigation with the Internal Revenue Service (IRS) related to certain interest deductions for a corporate owned life insurance (COLI) program; the ability of the Company to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; inflationary trends; changes in electricity market prices; interest rates; and other risks and unforeseen events.

Indiana Michigan Power Company (the Company) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, purchase, sale, transmission and distribution of electric power to 559,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan and conducts business as American Electric Power (AEP). The Company as a member of the AEP System Power Pool (AEP Power Pool) shares the revenues and costs of the AEP Power Pool's wholesale sales to neighboring utility systems and power marketers. The Company also sells wholesale power to municipalities and electric cooperatives.

The cost of the AEP System's generating capacity is allocated among the AEP Power Pool members based on their relative peak demands and generating reserves through the payment or receipt of capacity charges and credits. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool.

The AEP Power Pool calculates each Company's prior twelve month peak demand relative to the total peak demand of all member companies as a basis for sharing revenues and costs. The result of this calculation is each Company's member load ratio (MLR) which determines each Company's percentage share of revenues or costs. Since the Company's MLR decreased in 1999 and increased during 1998, the AEP Power Pool allocated to the Company a smaller share in 1999 and a larger share in 1998 of wholesale revenues and expenses.

Results of Operations

Net income declined $64 million or 66% in 1999 primarily due to the cost of efforts to restart the Company's two unit Donald C. Cook Nuclear Plant (Cook Plant) which was shutdown in September 1997 to address safety concerns and issues.

Although operating revenues increased $67 million or 5% in 1998, net income decreased $50 million or 34% due mainly to increased purchased power and maintenance expense related to the extended outage of the Cook Plant and the adverse effect on non-operating income of losses on certain non-regulated energy trades outside of the AEP Power Pool's traditional marketing area.

Operating Revenues

Operating revenues decreased 1% in 1999 and increased 5% in 1998. The decrease in 1999 was primarily due to a decline in margins on wholesale sales and net power trading transactions within the AEP Power Pool's traditional marketing area. An increase in retail revenues in 1998 was the primary reason for the 1998 increase. The following analyzes the changes in operating revenues:

	Increase (Decrease) From Previous Year			
	1999		1998	
	Amount	%	Amount	%
	(dollars in millions)			
Retail:				
Residential	$ 3.4		$ 26.4	
Commercial	0.7		26.1	
Industrial	(5.7)		38.1	
Other	(0.2)		0.4	
	(1.8)	(0.2)	91.0	9.6
Wholesale	(18.2)	(5.7)	(40.6)	(11.2)
Transmission	(0.3)	(1.1)	13.4	83.2
Miscellaneous	8.6	68.4	2.8	27.6
Total	$(11.7)	(0.8)	$ 66.6	5.0

Operating revenues decreased in 1999 primarily due to reduced margins on the Company's MLR share of wholesale sales and net revenues from regulated power trading transactions in the AEP Power Pool's traditional marketing area. The decline in margins reflects the moderation in 1999 of extreme weather in 1998 and capacity shortages experienced in the summer of 1998.

Revenues from retail customers increased significantly in 1998 due to the accrual of revenues under fuel adjustment clauses for the increased cost of replacement power and increased fossil fuel usage necessitated by the extended outage of the Company's two nuclear units and a 3% increase in sales. Under the retail jurisdictional fuel clauses, revenues are accrued for the unrecovered cost of fuel in both retail jurisdictions and for replacement power costs in the Michigan jurisdiction until approved for billing. See "Nuclear Plant Restart Effort" for discussion of settlement agreements in the Indiana and Michigan jurisdictions regarding recovery of deferred Cook Plant fuel-related revenues.

Wholesale revenues declined significantly in 1998 due to a decline in sales to the AEP Power Pool reflecting the unavailability of the nuclear units. The decline was partially offset by the Company's MLR share of increased power marketing sales and net trading transactions of the AEP Power Pool.

Operating Expenses Increase

Total operating expenses increased 4% in 1999 and 10% in 1998 primarily due to costs related to the extended Cook Plant outage and efforts to restart the units. The changes in the components of operating expenses were:

	Increase (Decrease) From Previous Year			
	1999		1998	
	Amount	%	Amount	%
	(dollars in millions)			
Fuel	$ 12.8	7.4	$(53.8)	(23.8)
Purchased Power	(21.1)	(7.1)	133.3	80.9
Other Operation	114.3	32.9	13.1	3.9
Maintenance	(22.3)	(14.1)	39.8	33.8
Depreciation and Amortization	4.9	3.4	4.3	3.1
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	-	-	(11.9)	(100.0)
Taxes Other Than Federal Income Taxes	(8.8)	(13.1)	2.6	4.1
Federal Income Taxes	(34.1)	(66.0)	(19.1)	(27.0)
Total	$ 45.7	3.7	$108.3	9.6

Fuel expense increased in 1999 primarily due to an increase in coal-fired generation as more internal generation was utilized in place of purchasing power from the AEP Power Pool. The decrease in fuel expense in 1998 was principally due to the unavailability of the Company's two nuclear generating units from September 1997 through the end of 1999. See Nuclear Plant Restart Effort discussed below.

The decrease in purchased power expense in 1999 reflects the purchase of less power in 1999 at lower prices from the AEP Power Pool, AEP Generating Company, an affiliate that is not a member of the AEP Power Pool and unaffiliated entities. Purchased power expense increased significantly in 1998 due to increased purchases from the AEP Power Pool and the Company's MLR share of increased purchases of electricity by the AEP Power Pool. The purchases were made to replace power previously generated by the unavailable nuclear units and to supply the electricity for the AEP Power Pool's wholesale marketing sales.

The increases in other operation expense in 1999 and 1998 were due to expenditures to prepare the nuclear units for restart.

Maintenance expense declined in 1999 due to cost containment efforts including staff reductions at the Company's fossil-fired power plants, in the engineering and maintenance staff of AEP Service Corporation and in the Company's transmission and distribution operations. The increase in maintenance expense in 1998 was due to expenditures to prepare the Cook Plant for restart.

The recovery period for the Rockport Plant Unit 1 cost deferral under rate phase-in plans in the Indiana and the Federal Energy Regulatory Commission (FERC) jurisdictions ended in 1997 causing the decrease in the amortization of phase-in plan deferrals. The deferred costs were amortized over a 10-year period commensurate with their collection from customers.

The decrease in taxes other than federal income taxes in 1999 is primarily due to a decline in estimated taxable income for Indiana supplemental income tax.

Federal income taxes attributable to operations decreased in 1999 and 1998 due to decreases in pre-tax operating income.

<u>Nonoperating Income</u>

The increase in nonoperating income in 1999 is primarily due to the effect of non-regulated electricity trading transactions, which resulted in a gain in 1999 and a loss in 1998. The decline in nonoperating income in 1998 is due to net losses from non-regulated electricity trading transactions outside of the AEP Power Pool's traditional marketing area which are marked-to-market.

<u>Interest Charges</u>

Interest charges increased in 1999 due to increased borrowings to support expenditures, both current and deferred, for the Cook Plant restart effort.

<u>Business Outlook</u>

The most significant factors affecting the Company's future earnings are the restart of the Cook Plant nuclear generating units; weather in the service territories served by the Company and its wholesale customers; generating unit availability; the ability to recover costs as the electric generating business becomes more competitive; the outcome of litigation with the IRS related to certain interest deductions for a COLI program; and the outcome of ongoing environmental litigation and proposed air quality standards. In 1999 significant progress was made related to many of these major challenges.

Nuclear Plant Restart Effort

Management shut down both units of the Cook Plant in September 1997 due to questions regarding the operability of certain safety systems that arose during a Nuclear Regulatory Commission (NRC) architect engineer design inspection. The NRC issued a Confirmatory Action Letter in September 1997 requiring the Company to address certain issues identified in the letter. In 1998 the NRC notified the Company that it had convened a Restart Panel for Cook Plant and provided a list of required restart activities. In order to identify and resolve all issues necessary to restart the Cook units, the Company is working with the NRC and will be meeting with the Panel on a regular basis until the units are returned to service. In a February 2, 2000 letter from the NRC, the Company was notified that the Confirmatory Action Letter had been closed. Closing of the Confirmatory Action Letter is one of the key approvals needed to restart the nuclear units.

The Company's plan to restart the Cook Plant units has Unit 2 scheduled to restart in April 2000 and Unit 1 scheduled to restart in September 2000. The restart plan was developed based upon a comprehensive systems readiness review of all operating systems at the Cook Plant. When maintenance and other work including testing required for restart are complete, the Company will seek concurrence from the NRC to restart the Cook Plant units. Any issues or difficulties encountered in testing of equipment as part of the restart process could delay the scheduled restart dates. Earnings for 2000 will be adversely affected by restart expenses expected to be incurred in 2000, which are estimated to be $200 million, and amortization of previously deferred non-fuel restart costs and fuel-related revenues of $78 million.

Replacement of the steam generator for Unit 1 will be completed before it is returned to service. Costs associated with the steam generator replacement are estimated to be approximately $165 million, which will be accounted for as a capital investment unrelated to the restart. At December 31, 1999, $119 million has been spent on the steam generator replacement.

The cost of electricity supplied to retail customers increased due to the outage of the two Cook Plant nuclear units since higher cost coal-fired generation and coal-based purchased power is being substituted for the unavailable low cost nuclear generation. With regulator approvals, actual replacement energy fuel costs that exceeded the costs reflected in billings were recorded as a regulatory asset under the Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms.

On March 30, 1999, the Indiana Utility Regulatory Commission (IURC) approved a settlement agreement that resolved all matters related to the recovery of replacement energy fuel costs and all outage/restart costs and related issues during the extended outage of the Cook Plant. The settlement agreement provided for, among other things, a replacement fuel billing credit of $55 million, including interest, to Indiana retail customers' bills; the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999, including the billing credit; the deferral of up to $150 million of jurisdictional restart related nuclear operation and maintenance costs in 1999 above the amount included in base rates; the amortization of the deferred fuel and non-fuel operation and maintenance cost deferrals over a five-year period ending December 31, 2003; a freeze in base rates through December 31, 2003; and a fixed fuel recovery charge until March 1, 2004. The $55 million credit was applied to retail customers' bills during the months of July, August and September 1999.

On December 16, 1999, the Michigan Public Service Commission (MPSC) approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases which resolves all issues related to the Cook Plant extended outage. The settlement agreement limits the Company's ability to increase base rates and freezes the power supply cost recovery factor through December 31, 2003; permits the deferral of up to $50 million in 1999 of jurisdictional non-fuel restart nuclear operation and maintenance expenses and authorizes the amortization of power supply cost recovery revenues accrued from September 9, 1997 to December 31, 1999 and non-fuel nuclear operation and maintenance costs deferrals over a five-year period ending December 31, 2003.

Expenditures to restart the Cook units are estimated to total approximately $574 million. Through December 31, 1999, $373 million has been spent. These expenditures are not capital in nature and as such have negatively affected current earnings and will negatively affect earnings in 2000, and through amortization of the above described deferrals through December 31, 2003. In 1999 the restart costs incurred were $289 million of which $200 million were deferred for amortization over a five-year period, beginning January 1, 1999, in accordance with the settlement agreements. Consequently, $129 million of restart costs negatively affected 1999 earnings inclusive of $40 million of amortization of deferred restart costs. Also reflected in 1999 earnings is amortization of $38 million of fuel-related revenues. At December 31, 1999, regulatory assets included $160 million of deferred restart related operation and maintenance costs. Also deferred as a regulatory asset at December 31, 1999 was $150 million of fuel-related revenues.

The costs of the extended outage and restart efforts will have a material adverse effect on future results of operations and possibly financial condition through 2003 and on cash flows through 2000. Management believes that the Cook units will be successfully restarted in April and September 2000, however, if for some unknown reason the units are not returned to service or their restart is delayed significantly it would have an even greater adverse effect on future results of operations, cash flows and financial condition.

<u>Restructuring Activities</u>

The introduction of competition and customer choice for retail customers in the Company's service territory has been slow and continues at a deliberate pace as legislators and regulatory officials recognize the complexity of the issues. Federal legislation has been proposed to mandate competition and customer choice at the retail level, and several states have introduced or are considering similar legislation. The MPSC has started a program for certain utilities to phase-in to competition with the objective of providing full customer choice by 2002. The Company has begun discussions with the MPSC and other interested parties to formulate a plan. The actions by the MPSC were not mandated by legislation and are subject to a number of uncertainties and it is not presently possible to determine what impact if any the resolution of these matters will have on the operations of the Company. Indiana is considering legislative initiatives to move to customer choice, although the timing is uncertain. The Company supports customer choice and is proactively involved in discussions at both the state and federal levels regarding the best competitive market structure and method to transition to a competitive marketplace.

As the pricing of generation in the electric energy market evolves from regulated cost-of-service ratemaking to market-based rates, many complex issues must be resolved, including the recovery of stranded costs. Stranded costs are those costs above market that potentially would not be recoverable in a competitive market. At the wholesale level recovery of stranded costs under certain conditions was addressed by the FERC when it established rules for open transmission access and competition in the wholesale markets. However, the issue of stranded cost is unresolved at the retail level where it is much larger than it is at the wholesale level. The amount of stranded cost the Company could experience depends on the timing and extent to which competition is introduced to its generation business and the future market prices of electricity. The recovery of stranded cost is dependent on the terms of future legislation and related regulatory proceedings.

Under the provisions of Statement of Financial Accounting Standards (SFAS) 71 "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) are included in the consolidated balance sheets of cost-based regulated utilities in accordance with regulatory actions to match expenses and revenues. In order to maintain net regulatory assets on the balance sheet, SFAS 71 requires that rates charged to customers be cost-based and provide for the probable recovery of regulatory assets over future accounting periods. Management has concluded that as of December 31, 1999 the requirements to apply SFAS 71 continue to be met.

In the event a portion of the Company's business no longer meets the requirements of SFAS 71, SFAS 101 "Accounting for the Discontinuance of Application of Statement 71" requires that net regulatory assets be written off for that portion of the business. The provisions of SFAS 71 and SFAS 101 did not anticipate or provide accounting guidance for an extended transition period and for recovery of stranded costs during and after a transition period through a wires charge or regulated distribution rates. In 1997 the Financial Accounting Standards Board's (FASB) Emerging Issues Task Force (EITF) addressed such a situation with the consensus reached on issue 97-4 that requires that the application of SFAS 71 to a segment of a regulated electric utility cease when that segment is subject to a legislatively approved plan for transition to competitive market pricing from cost-based regulated rates and/or a rate order is issued containing sufficient detail for the utility to reasonably determine what the restructuring plan would entail and how it will affect the utility's financial statements. The EITF indicated that the cessation of application of SFAS 71 would require that regulatory assets and impaired stranded plant cost applicable to the portion of the business that was no longer cost-based regulated be written off unless they are recoverable in the future through cost-based regulated rates.

Although certain FERC orders provide for competition in the firm wholesale market, that market is a relatively small part of our business and most of our firm wholesale sales are still under cost-of-service contracts. As a result, the Company's generation business is still cost-based regulated and should remain so for the near future. We believe that enabling federal and state legislation should provide for the recovery of any generation-related net regulatory assets and other reasonable stranded costs from impaired generating assets. However, if in the future the Company's generation business were to no longer be cost-based regulated and if it were not possible to demonstrate probability of recovery of resultant stranded costs including regulatory assets, results of operations, cash flows and financial condition would be adversely affected.

The Company supports the orderly transition to market pricing for electricity because we believe our low cost generating units provide us with a competitive advantage provided the legislators and/or regulators provide a level playing field for all competitors. The Company is working to develop and acquire the necessary skills and competencies to succeed in a competitive electricity commodity market. The AEP Power Pool has developed an extensive wholesale electricity trading business. However, many factors, some of which the Company does not control, could negatively impact future success in a market price based, competitive environment.

Customer choice and competition could ultimately result in adverse impacts on results of operations and cash flows depending on the future market prices of electricity and the ability of the Company to recover its stranded costs including net regulatory assets during a transition period and during a subsequent period through a wires charge or other recovery mechanism. We believe that enabling state legislation and the regulatory process should provide for the full recovery of generation related net regulatory assets and other reasonable stranded costs. However, if in the future any portion of the generation business in our jurisdictions were to no longer be cost-based regulated and if it were not possible to demonstrate probability of recovery of resultant stranded costs including regulatory assets, results of operations, cash flows and financial condition would be adversely affected.

Environmental Concerns and Issues

We take great pride in our efforts to economically produce and deliver electricity while minimizing the impact on the environment. The Company has spent hundreds of millions of dollars to equip our facilities with the latest cost effective clean air and water technologies and to research new technologies. We intend to continue in a leadership role fostering economically prudent efforts to protect and preserve the environment while providing a vital commodity, electricity, to our customers at a fair price.

Air Quality

In 1998 the United States (U.S.) Environmental Protection Agency (Federal EPA) issued a final rule which requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including the states in which the Company's generating plants are located. A number of utilities, including the Company, filed petitions seeking a review of the final rule in the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court). On March 3, 2000, the Appeals Court issued a decision generally upholding Federal EPA's final rule on NOx emission reductions.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to Section 126 of the Clean Air Act. The Rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are approximately equivalent to the reductions contemplated by the NOx emission reduction final rule. The Company and its affiliates in the AEP System with coal-fired generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of the Section 126 Rule. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on compliance with an 8-hour ozone standard remanded by the Appeals Court, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule requiring 392 industrial plants, including certain generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves petitions of four northeastern states which contend that their failure to meet Federal EPA smog standards is due to coal-fired generating plants in upwind states, including many plants in the AEP System, and not their automobiles and other local sources.

Preliminary estimates indicate that compliance with the Federal EPA's final rule on NOx emission reductions that was upheld by the Appeals Court could result in required capital expenditures of approximately $202 million for the Company. It should be noted, however, that compliance costs cannot be estimated with certainty since actual costs incurred to comply could be significantly different from this preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless compliance costs are recovered from customers through regulated rates, such compliance costs will have an adverse effect on future results of operations, cash flows and possibly financial condition.

Federal EPA Complaint and Notice of Violation

Under the Clean Air Act, if a fossil plant undergoes a major modification that results in a significant emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

On November 3, 1999, the Department of Justice, at the request of Federal EPA, filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company and its affiliates in the AEP System made modifications to certain of their coal-fired generating plants over the course of the past 25 years that extend their operating lives or increase their generating capacity in violation of the Clean Air Act. Federal EPA also issued Notices of Violation alleging violations of certain provisions of the Clean Air Act at certain AEP System plants. A number of unaffiliated utilities also received Notices of Violation, complaints or administrative orders.

The states of New Jersey, New York and Connecticut were subsequently allowed to join Federal EPA's action against the AEP System companies under the Clean Air Act. On November 18, 1999, a number of environmental groups filed a lawsuit against power plants owned by the Company and its AEP System affiliates alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action has been consolidated with the Federal EPA action. The complaints and Notices of Violation named one of the Company's two coal-fired generating plants. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act provisions and intends to vigorously pursue its defense of this matter.

The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts all of Federal EPA's contentions, could be substantial. In the event the Company does not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates.

Financial Condition

The Company issued $250 million principal amount of long-term obligations in 1999; $150 million with an interest rate of 6-7/8% and $100 million with a variable interest rate. The principal amount of long-term debt retirements, including maturities, totaled $110 million at interest rates ranging from 6.55% to 7.3%. Our senior secured debt/first mortgage bond ratings are: Moody's, Baa1; Standard & Poor's, A-; and Fitch, BBB+.

Gross plant and property additions were $178 million in 1999 and $159 million in 1998. Management estimates construction expenditures for the next three years to be $329 million. The funds for construction of new facilities and improvement of existing facilities can come from a combination of internally generated funds, short-term and long-term borrowings, preferred stock issuances and investments in common equity by AEP Co., Inc. However, all of the construction expenditures for the next three years are expected to be financed with internally generated funds.

When necessary the Company generally issues short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds. At December 31, 1999, $1,056 million of unused short-term lines of credit shared with other AEP System companies were available. Short-term debt borrowings are limited by provisions of the Public Utility Holding Company Act of 1935 to $500 million. Generally periodic reductions of outstanding short-term debt are made through issuances of long-term debt and additional capital contributions by the parent company.

The Company's earnings coverage presently exceeds all minimum coverage requirements for the issuance of mortgage bonds. The minimum coverage ratio is 2.0 for mortgage bonds and at December 31, 1999, the mortgage bond coverage ratio was 4.81.

The Company is committed under unit power agreements to purchase all of an affiliate's share, 50% of the 2,600 megawatt (mw) Rockport Plant capacity, unless it is sold to other utilities. The affiliate had a long-term unit power agreement that expired at the end of 1999 for the sale of 455 mw to an unaffiliated utility. Revenues received by the affiliate under this agreement were $64 million in 1999. An agreement between the affiliate which owns Rockport Plant and another affiliate provides for the sale of 390 mw of capacity to that affiliate through 2004. Effective January 1, 2000, the Company is required to purchase 910 mw of its affiliate's 50% share of Rockport Plant capacity.

Market Risks

The Company has certain market risks inherent in its business activities from changes in electricity commodity prices and interest rates. As a member of the AEP Power Pool, trading of electricity and related financial derivative instruments by the AEP Power Pool exposes the Company to market risk. Market risk represents the risk of loss that may impact the Company due to adverse changes in electricity commodity market prices and rates. Policies and procedures have been established to identify, assess and manage market risk exposures including the use of a risk measurement model which calculates Value at Risk (VaR). The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assuming a 95% confidence level and a three-day holding period. Throughout 1999 and 1998, the Company's share of the highest, lowest and average quarterly VaR in the wholesale trading portfolio was less than $2.7 million and $2 million, respectively. Based on this VaR analysis, at December 31, 1999 a near term change in commodity prices is not expected to have a material effect on the Company's results of operations, cash flows or financial condition.

The Company is exposed to changes in interest rates primarily due to short-term and long-term borrowings to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to 39 years and an average duration of five years at December 31, 1999. The Company measures interest rate market risk exposure utilizing a VaR model. The interest rate VaR model is based on a Monte Carlo simulation with a 95% confidence level and a one year holding period. The volatilities and correlations were based on three years of weekly prices. The risk of potential loss in fair value attributable to the Company's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $127 million at December 31, 1999 and $102 million at December 31, 1998. The Company would not expect to liquidate its entire debt portfolio in a one year holding period. Therefore, a near term change in interest rates should not materially affect results of operations or the consolidated financial position of the Company.

Inflation affects the Company's cost of replacing utility plant and the cost of operating and maintaining its plant. The rate-making process generally limits our recovery to the historical cost of assets resulting in economic losses when the effects of inflation are not recovered from customers on a timely basis. However, economic gains that result from the repayment of long-term debt with inflated dollars partly offset such losses.

Litigation

Corporate Owned Life Insurance

The IRS agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's COLI program should not be allowed. As a result of a suit filed by the Company in U.S. District Court (discussed below) the request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings by approximately $66 million (including interest).

The Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the Consolidated Balance Sheets in other property and investments pending the resolution of this matter. The Company is seeking refund through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the U.S. in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI deductions should be disallowed. Notwithstanding the Tax Court's decision in Winn-Dixie management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

The Company is involved in a number of other legal proceedings and claims. While management is unable to predict the outcome of such litigation, it is not expected that the ultimate resolution of these matters will have a material adverse effect on the results of operations, cash flows or financial condition.

Other Matters

Superfund

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and spent nuclear fuel (SNF). Coal combustion by-products are typically disposed of or treated in captive disposal facilities or are beneficially utilized. In addition, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls (PCBs) and other hazardous and nonhazardous materials. The Company is currently incurring costs to safely dispose of such substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) addresses clean-up of hazardous substances at disposal sites and authorizes Federal EPA to administer the clean-up programs. As of year-end 1999, the Company has been named by the Federal

EPA as a potentially responsible party (PRP) for two sites. Historically, the Company's liability has been resolved for a number of sites with no significant effect on results of operations and present estimates do not anticipate material cleanup costs for identified sites for which we have been declared a PRP. However, if for reasons not currently identified significant cleanup costs are incurred, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

The Clean Air Act Amendments (CAAA) required Federal EPA to issue rules to implement the law. In 1996 Federal EPA issued final rules governing NOx emissions that must be met after January 1, 2000 (Phase II of CAAA). The final rules required substantial reductions in NOx emissions from certain types of boilers including those in the power plants of the Company and its affiliates in the AEP System. To comply with Phase II of CAAA, the Company installed NOx emission control equipment on certain units and switched fuel at other units. The Company is operating under the Phase II rules which require reporting at the end of each year. The Company does not anticipate any material problems complying with the rules.

At the Third Conference of the Parties to the United Nations Framework Convention on Climate Change held in Kyoto, Japan in December 1997 more than 160 countries, including the U.S., negotiated a treaty requiring legally-binding reductions in emissions of greenhouse gases, chiefly carbon dioxide, which many scientists believe are contributing to global climate change. The treaty, which requires the advice and consent of the U.S. Senate for ratification, would require the U.S. to reduce greenhouse gas emissions seven percent below 1990 levels in the years 2008-2012. Although the U.S. has agreed to the treaty and signed it on November 12, 1998, President Clinton has indicated that he will not submit the treaty to the Senate for consideration until it contains requirements for "meaningful participation by key developing countries" and the rules, procedures, methodologies and guidelines of the treaty's emissions trading and joint implementation programs and compliance enforcement provisions have been negotiated. At the Fourth Conference of the Parties, held in Buenos Aires, Argentina, in November 1998, the parties agreed to a work plan to complete negotiations on outstanding issues with a view toward approving them at the Sixth Conference of the Parties to be held in November 2000. We will continue to work with the Administration and Congress to develop responsible public policy on this issue.

If the Kyoto treaty is approved by Congress, the costs to comply with the emission reductions required by the treaty are expected to be substantial and would have a material adverse impact on results of operations, cash flows and possibly financial condition if not recovered from customers. It is management's belief, that the Kyoto protocol is unlikely to be ratified or implemented in the U.S. in its current form.

<u>Costs for Spent Nuclear Fuel and Decommissioning</u>

The Company, as the owner of the Cook Plant, like other nuclear power plants, has a significant future financial commitment to safely dispose of SNF and decommission and decontaminate the plant. The Nuclear Waste Policy Act of 1982 established federal responsibility for the permanent off-site disposal of SNF and high-level radioactive waste. By law the Company participates in the Department of Energy's (DOE) SNF disposal program which is described in Note 5 of the Notes to Consolidated Financial Statements. Since 1983 we have collected $272 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $115 million of these funds have been deposited in external trust funds to provide for the future disposal of SNF and $157 million has been remitted to the DOE. Under the provisions of the Nuclear Waste Policy Act, collections from customers are to provide the DOE with money to build a permanent repository for spent fuel. However, in December 1996, the DOE notified the Company that it would be unable to begin accepting SNF by the January 1998 deadline required by law. To date DOE has failed to comply with the requirements of the Nuclear Waste Policy Act.

As a result of DOE's failure to make sufficient progress toward a permanent repository or otherwise assume responsibility for SNF, the Company along with a number of unaffiliated utilities and states filed suit in the Appeals Court requesting, among other things, that the Appeals Court order DOE to meet its obligations under the law. The Appeals Court ordered the parties to proceed with contractual remedies but declined to order DOE to begin accepting SNF for disposal. DOE estimates its planned site for the nuclear waste will not be ready until at least 2010. In 1998, the Company filed a complaint in the U.S. Court of Federal Claims seeking damages in excess of $150 million due to the DOE's partial material breach of its unconditional contractual deadline to begin disposing of SNF generated by the Cook Plant. Similar lawsuits were filed by other utilities. On April 6, 1999, the Court granted DOE's motion to dismiss a lawsuit filed by another utility. On May 20, 1999, the other utility appealed this decision to the U.S. Court of Appeals for the Federal Circuit. The Company's case has been stayed pending final resolution of the other utility's appeal. As long as the delay in the availability of a government approved storage repository for SNF continues, the cost of both temporary and permanent storage will continue to increase.

The cost to decommission the Cook Plant is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 1997 estimate the cost to decommission the Cook Plant ranges from $700 million to $1,152 million in 1997 nondiscounted dollars. This estimate could escalate due to continued uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 1999, the total decommissioning trust fund balance was $498 million which includes earnings on the trust investments. We will work with regulators and customers to recover the remaining estimated cost of decommissioning the Cook Plant. However, future results of operations, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Year 2000 Readiness Disclosure

On or about midnight on December 31, 1999, digital computing systems could have produced erroneous results or failed, unless these systems had been modified or replaced, because such systems may have been programmed incorrectly and interpreted the date of January 1, 2000 as being January 1st of the year 1900 or another incorrect date. In addition, certain systems may fail to detect that the year 2000 is a leap year or otherwise incorrectly interpret a year 2000 date.

The Company has not experienced any material failure of generation and delivery of electric energy due to Year 2000 because of the AEP System's preparations. Such preparation included the modification or replacement of certain computer hardware and software to minimize Year 2000-related failures and repair. This included both information technology systems (IT), which are mainframe and client server applications, and embedded logic systems (non-IT), such as process controls for energy production and delivery. Externally, the problem was addressed with entities that interact with the Company, including suppliers, customers, creditors, financial service organizations and other parties essential to the Company's operations. In the course of the external evaluation, the Company sought written assurances from third parties regarding their state of Year 2000 readiness. Another issue addressed was the impact of electric power grid problems that may have occurred outside of our transmission system.

Through December 31, 1999, the Company's share of the AEP System's expenditures on the Year 2000 project was $8 million. Most Year 2000 costs were for IT contractors and consultants and for salaries of internal IT professionals and were expensed; however, in certain cases the Company acquired hardware and new software that was capitalized.

New Accounting Standards

The FASB issued SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" in June 1998. SFAS 133 establishes accounting and reporting standards for derivative instruments. It requires that all derivatives be recognized as either an asset or a liability and measured at fair value in the financial statements. If certain conditions are met, a derivative may be designated as a hedge of possible changes in fair value of an asset, liability or firm commitment; variable cash flows of forecasted transactions; or foreign currency exposure. The accounting/reporting for changes in a derivative's fair value (gains and losses) depend on the intended use and resulting designation of the derivative. Management is currently studying the provisions of SFAS 133 and reviewing the Company's contracts and transactions to determine the impact on the Company's results of operations, cash flows and financial condition when SFAS 133 is adopted on January 1, 2001.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of
Directors of Indiana Michigan Power Company:

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and its subsidiaries as of December 31, 1999 and 1998, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1999. 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, such consolidated financial statements present fairly, in all material respects, the financial position of Indiana Michigan Power Company and its subsidiaries as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with generally accepted accounting principles.

Deloitte + Touche LLP

DELOITTE & TOUCHE LLP
Columbus, Ohio
February 22, 2000
(March 3, 2000 as to Note 6)

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
OPERATING REVENUES	$1,394,119	$1,405,794	$1,339,232
OPERATING EXPENSES:			
Fuel	185,419	172,592	226,402
Purchased Power	276,962	298,046	164,775
Other Operation	461,494	347,207	334,115
Maintenance	135,331	157,593	117,780
Depreciation and Amortization	149,988	145,112	140,812
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	-	-	11,871
Taxes Other Than Federal Income Taxes	58,713	67,592	64,945
Federal Income Taxes	17,560	51,645	70,744
Total Operating Expenses	1,285,467	1,239,787	1,131,444
OPERATING INCOME	108,652	166,007	207,788
NONOPERATING INCOME (LOSS)	4,530	(839)	4,415
INCOME BEFORE INTEREST CHARGES	113,182	165,168	212,203
INTEREST CHARGES	80,406	68,540	65,463
NET INCOME	32,776	96,628	146,740
PREFERRED STOCK DIVIDEND REQUIREMENTS	4,885	4,824	5,736
EARNINGS APPLICABLE TO COMMON STOCK	$ 27,891	$ 91,804	$ 141,004

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

	December 31,	
	1999	1998
	(in thousands)	
ASSETS		
ELECTRIC UTILITY PLANT:		
Production	$2,587,288	$2,565,041
Transmission	928,758	913,495
Distribution	818,697	768,888
General (including nuclear fuel)	244,981	228,013
Construction Work in Progress	190,303	156,411
Total Electric Utility Plant	4,770,027	4,631,848
Accumulated Depreciation and Amortization	2,194,397	2,081,355
NET ELECTRIC UTILITY PLANT	2,575,630	2,550,493
NUCLEAR DECOMMISSIONING AND SPENT NUCLEAR FUEL DISPOSAL TRUST FUNDS	707,967	648,307
OTHER PROPERTY AND INVESTMENTS	213,658	197,368
CURRENT ASSETS:		
Cash and Cash Equivalents	3,863	5,424
Accounts Receivable:		
Customers	91,268	94,502
Affiliated Companies	48,901	26,569
Miscellaneous	18,644	18,743
Allowance for Uncollectible Accounts	(1,848)	(2,027)
Fuel - at average cost	27,597	20,857
Materials and Supplies - at average cost	84,149	78,009
Accrued Utility Revenues	44,428	37,277
Energy Marketing and Trading Contracts	97,946	14,105
Prepayments	7,631	4,848
TOTAL CURRENT ASSETS	422,579	298,307
REGULATORY ASSETS	624,810	421,475
DEFERRED CHARGES	32,052	32,573
TOTAL	$4,576,696	$4,148,523

See Notes to Consolidated Financial Statements.

	December 31, 1999	December 31, 1998
	(in thousands)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common Stock - No Par Value:		
Authorized - 2,500,000 Shares		
Outstanding - 1,400,000 Shares	$ 56,584	$ 56,584
Paid-in Capital	732,739	732,605
Retained Earnings	166,389	253,154
Total Common Shareholder's Equity	955,712	1,042,343
Cumulative Preferred Stock:		
Not Subject to Mandatory Redemption	9,248	9,273
Subject to Mandatory Redemption	64,945	68,445
Long-term Debt	1,126,326	1,140,789
TOTAL CAPITALIZATION	2,156,231	2,260,850
OTHER NONCURRENT LIABILITIES:		
Nuclear Decommissioning	501,185	445,934
Other	242,522	240,320
TOTAL OTHER NONCURRENT LIABILITIES	743,707	686,254
CURRENT LIABILITIES:		
Long-term Debt Due Within One Year	198,000	35,000
Short-term Debt	224,262	108,700
Accounts Payable - General	78,784	53,187
Accounts Payable - Affiliated Companies	31,118	37,647
Taxes Accrued	48,970	35,161
Interest Accrued	13,955	15,279
Obligations Under Capital Leases	11,072	9,667
Energy Marketing and Trading Contracts	95,564	15,228
Other	91,684	72,065
TOTAL CURRENT LIABILITIES	793,409	381,934
DEFERRED INCOME TAXES	622,157	559,288
DEFERRED INVESTMENT TAX CREDITS	121,627	129,779
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	85,005	88,712
DEFERRED CREDITS	54,560	41,706
COMMITMENTS AND CONTINGENCIES (Notes 5 and 6)		
TOTAL	$4,576,696	$4,148,523

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
OPERATING ACTIVITIES:			
Net Income	$ 32,776	$ 96,628	$ 146,740
Adjustments for Noncash Items:			
Depreciation and Amortization	153,921	149,209	148,630
Amortization of Rockport Plant Unit 1 Phase-in Plan Deferrals	-	-	11,871
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses (net)	8,480	14,142	(15,967)
Deferred Nuclear Outage Costs (net)	(160,000)	-	-
Deferred Federal Income Taxes	85,727	17,905	3,922
Deferred Investment Tax Credits	(8,152)	(8,266)	(8,428)
Underrecovery of Fuel and Purchased Power	(84,696)	(46,846)	(22,812)
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(19,178)	1,462	(10,504)
Fuel, Materials and Supplies	(12,880)	(2,983)	5,168
Accrued Utility Revenues	(7,151)	(6,756)	7,774
Accounts Payable	19,068	22,440	6,502
Taxes Accrued	13,809	(11,689)	(18,550)
Payment of Disputed Tax and Interest Related to COLI	(3,228)	(53,628)	-
Other (net)	12,831	(8,176)	5,817
Net Cash Flows From Operating Activities	31,327	163,442	260,163
INVESTING ACTIVITIES:			
Construction Expenditures	(165,331)	(147,627)	(122,360)
Proceeds from Sales of Property and Other	2,501	4,419	2,016
Net Cash Flows Used For Investing Activities	(162,830)	(143,208)	(120,344)
FINANCING ACTIVITIES:			
Issuance of Long-term Debt	247,989	170,675	47,728
Retirement of Cumulative Preferred Stock	(3,597)	(120)	(78,877)
Retirement of Long-term Debt	(109,500)	(55,000)	(50,000)
Change in Short-term Debt (net)	115,562	(10,900)	76,100
Dividends Paid on Common Stock	(114,656)	(117,464)	(131,260)
Dividends Paid on Cumulative Preferred Stock	(5,856)	(4,734)	(5,931)
Net Cash Flows From (Used For) Financing Activities	129,942	(17,543)	(142,240)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,561)	2,691	(2,421)
Cash and Cash Equivalents January 1	5,424	2,733	5,154
Cash and Cash Equivalents December 31	$ 3,863	$ 5,424	$ 2,733

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1999	1998	1997
		(in thousands)	
Retained Earnings January 1	$253,154	$278,814	$269,071
Net Income	32,776	96,628	146,740
	285,930	375,442	415,811
Deductions:			
Cash Dividends Declared:			
Common Stock	114,656	117,464	131,260
Cumulative Preferred Stock:			
4-1/8% Series	244	247	249
4.56% Series	66	67	88
4.12% Series	78	79	80
5.90% Series	963	985	985
6-1/4% Series	1,250	1,266	1,266
6.30% Series	834	834	834
6-7/8% Series	1,238	1,255	1,255
Total Cash Dividends Declared	119,329	122,197	136,017
Capital Stock Expense	212	91	980
Total Deductions	119,541	122,288	136,997
Retained Earnings December 31	$166,389	$253,154	$278,814

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES:

Organization

Indiana Michigan Power Company (the Company or I&M) is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP Co., Inc.), a public utility holding company. The Company is engaged in the generation, purchase, sale, transmission and distribution of electric power to 559,000 retail customers in its service territory in northern and eastern Indiana and a portion of southwestern Michigan and conducts business as American Electric Power (AEP). Under the terms of the AEP System Power Pool (AEP Power Pool) and the AEP System Transmission Equalization Agreement, the Company's generation and transmission facilities are operated in conjunction with the facilities of certain other affiliated utilities as an integrated utility system. The Company as a member of the AEP Power Pool shares in the revenues and costs of the AEP Power Pool's wholesale sales to utility systems and power marketers. The Company also sells wholesale power to municipalities and electric cooperatives.

The Company has two wholly-owned subsidiaries, that were formerly engaged in coal-mining operations which are consolidated in these financial statements, Blackhawk Coal Company and Price River Coal Company. Blackhawk Coal Company currently leases and subleases portions of its Utah coal rights, land and related mining equipment to unaffiliated companies. Price River Coal Company, which owns no land or mineral rights, is inactive. The Company's River Transportation Division provides barging services to affiliated and unaffiliated companies.

Regulation

As a subsidiary of AEP Co., Inc., the Company is subject to the regulation of the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (1935 Act). Retail rates are regulated by the Indiana Utility Regulatory Commission (IURC) and the Michigan Public Service Commission (MPSC). The Federal Energy Regulatory Commission (FERC) regulates wholesale and transmission rates.

Principles of Consolidation

The consolidated financial statements include the revenues, expenses, cash flows, assets, liabilities and equity of I&M and its wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation.

Basis of Accounting

As a cost-based rate-regulated entity, I&M's financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with Statement of Financial Accounting Standards (SFAS) 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (deferred income) are recorded to reflect the economic effects of regulation and to match expenses with regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with generally accepted accounting principles requires in certain instances the use of estimates. Actual results could differ from those estimates.

Utility Plant

Electric utility plant is stated at original cost and is generally subject to first mortgage liens. Additions, major replacements and betterments are added to the plant accounts. Retirements of plant are deducted from the electric utility plant in service account and are deducted from accumulated depreciation together with associated removal costs, net of salvage. The costs of labor, materials and overheads incurred to operate and maintain utility plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of utility plant. It represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 1999, 1998 and 1997 were not significant.

Depreciation and Amortization

Depreciation of electric utility plant is provided on a straight-line basis over the estimated useful lives of utility plant and is calculated largely through the use of composite rates by functional class. The annual composite depreciation rates for 1999, 1998 and 1997 are as follows:

Functional Class of Property	Annual Composite Depreciation Rates		
	1999	1998	1997
Production:			
Steam-Nuclear	3.4%	3.4%	3.4%
Steam-Fossil-Fired	4.5%	4.4%	4.4%
Hydroelectric-Conventional	3.4%	3.4%	3.2%
Transmission	1.9%	1.9%	1.9%
Distribution	4.2%	4.2%	4.2%
General	3.8%	3.8%	3.8%

Amounts for the demolition and removal of non-nuclear plant are charged to the accumulated provision for depreciation and recovered through depreciation charges included in rates. The accounting and rate-making treatment afforded nuclear decommissioning costs and nuclear fuel disposal costs are discussed in Note 5.

Cash and Cash Equivalents

Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Operating Revenues and Fuel Costs

Revenues include billed revenues as well as an accrual for electricity consumed but unbilled at month-end. Fuel costs are matched with revenues in accordance with rate commission orders. Through December 31, 1999, revenues were accrued related to unrecovered fuel in both state retail jurisdictions and for replacement power costs in the Michigan jurisdiction until approved for billing. If the Company's earnings exceed the allowed return in the Indiana jurisdiction, the fuel clause mechanism provides for the refunding of the excess earnings to ratepayers. As part of settlement agreements related to fuel cost during an extended outage at the Donald C. Cook Nuclear Plant (Cook Plant) approved by the IURC and the MPSC, fuel costs could be deferred through December 31, 1999. Over or under recovered fuel from January 1, 2000 through February 29, 2004 in the Indiana jurisdiction and through December 31, 2003 in the Michigan jurisdiction will not be eligible for deferral due to fixed fuel recovery amounts in the settlement agreements. Effective March 1, 2004 and January 1, 2004, the fixed fuel recovery amount will expire and the Company will return to recording over and under recovery of fuel costs for the Indiana and Michigan jurisdictions, respectively, assuming that generation is still cost-based rate regulated. Substantially all FERC wholesale jurisdictional fuel cost changes are expensed and billed as incurred. See Note 2 "Cook Nuclear Plant Shutdown" for a complete discussion of the settlement agreements.

Energy Marketing and Trading Transactions

The AEP Power Pool administers and implements power marketing and trading transactions (trading activities) in which the Company shares. Trading activities involve the sale of electricity under physical forward contracts at fixed and variable prices and the trading of electricity contracts including exchange traded futures and options, over-the-counter options and swaps. The majority of these transactions represents physical forward electricity contracts in the AEP Power Pool's traditional marketing area and are typically settled by entering into offsetting contracts. The net revenues from these regulated transactions in AEP's traditional marketing area are included in operating revenues for rate-making, accounting and financial and regulatory reporting purposes.

In addition, the AEP Power Pool purchases and sells electricity options, futures and swaps, and enters into forward purchase and sale contracts for electricity outside of the AEP Power Pool's traditional marketing area. The Company's share of these non-regulated trading activities are included in nonoperating income.

In the first quarter of 1999 the Company adopted the Financial Accounting Standards Board's (FASB) Emerging Issues Task Force Consensus (EITF) 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." The EITF requires that all energy trading contracts be marked-to-market. The effect on the Consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for those open trading transactions within the AEP Power Pool's marketing area that are included in cost of service on a settlement basis for rate-making purposes. The Company's share of non-regulated open trading contracts are accounted for on a mark-to-market basis in nonoperating income. Unrealized mark-to-market gains and losses from trading activities are reported as assets and liabilities, respectively. The adoption of the EITF did not have a material effect on results of operations, cash flows or financial condition.

The Company enters into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses on the anticipatory debt instruments are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 1999 or 1998.

See Note 11 - Financial Instruments, Credit and Risk Management for further discussion.

Levelization of Nuclear Refueling Outage Costs

Incremental operation and maintenance costs associated with refueling outages at the Cook Plant are deferred commensurate with their rate-making treatment and amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.

Amortization of Cook Plant Deferred Restart Costs

Pursuant to settlement agreements approved by the IURC and the MPSC to resolve all issues related to the extended outage of the Cook Plant, the Company deferred certain operation and maintenance costs in 1999. The settlement agreements provide for the deferral of up to $150 million of Indiana jurisdictional and up to $50 million of Michigan jurisdictional non-fuel operation and maintenance costs incurred in 1999. The deferred amount will be amortized to expense on a straight-line basis over five years beginning January 1, 1999. The Company deferred $200 million and amortized $40 million in 1999 leaving $160 million as a SFAS 71 regulatory asset at December 31, 1999 on the Consolidated Balance Sheet. See Note 2 "Cook Nuclear Plant Shutdown" for a discussion of the settlement agreements.

Income Taxes

The Company follows the liability method of accounting for income taxes as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income taxes are provided for all temporary differences between the book cost and tax basis of assets and liabilities which will result in a future tax consequence. Where the flow-through method of accounting for temporary differences is reflected in rates (that is, deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established in accordance with SFAS 71.

Investment Tax Credits

Investment tax credits have been accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are being amortized over the life of regulated plant investment.

Debt and Preferred Stock

Gains and losses from the reacquisition of debt are deferred and amortized over the remaining term of the reacquired debt in accordance with rate-making treatment. If the debt is refinanced the reacquisition costs are deferred and amortized over the term of the replacement debt commensurate with their recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized over the term of the related debt, with the amortization included in interest charges.

Redemption premiums paid to reacquire preferred stock are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over the cost of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings.

Nuclear Decommissioning and Spent Nuclear Fuel Disposal Trust Funds

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel (SNF) are recorded at market value in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Securities in the trust funds have been classified as available-for-sale due to their long-term purpose. Under the provisions of SFAS 71, unrealized gains and losses from securities in these trust funds are not reported in equity but result in adjustments to the liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds.

Other Property and Investments

Other property and investments are stated at cost.

Comprehensive Income

There were no material differences between net income and comprehensive income.

Reclassification

Certain prior year amounts have been reclassified to conform to current year presentation. Such reclassifications had no impact on previously reported net income.

2. COOK NUCLEAR PLANT SHUTDOWN:

I&M owns and operates the two-unit 2,110 megawatt (mw) Cook Plant under licenses granted by the Nuclear Regulatory

Commission (NRC). The Company shut down both units of the Cook Plant in September 1997 due to questions regarding the operability of certain safety systems that arose during a NRC architect engineer design inspection. The NRC issued a Confirmatory Action Letter in September 1997 requiring the Company to address certain issues identified in the letter. In 1998 the NRC notified the Company that it had convened a Restart Panel for Cook Plant and provided a list of required restart activities. In order to identify and resolve the issues necessary to restart the Cook units, the Company is working with the NRC and will be meeting with the Panel on a regular basis until the units are returned to service. In a February 2, 2000 letter from the NRC, I&M was notified that the Confirmatory Action Letter had been closed. Closing of the Confirmatory Action Letter is one of the key approvals needed to restart the nuclear units.

The Company's plan to restart the Cook Plant units has Unit 2 scheduled to return to service in April 2000 and Unit 1 scheduled to return to service in September 2000. The restart plan was developed based upon a comprehensive systems readiness review of all operating systems at the Cook Plant. When maintenance and other work including testing required for restart are complete, the Company will seek concurrence from the NRC to return the Cook Plant to service. Any issues or difficulties encountered in testing of equipment as part of the restart process could delay the scheduled restart dates.

Replacement of the steam generator for Unit 1 will be completed before it is returned to service. Costs associated with the steam generator replacement are estimated to be approximately $165 million, which will be accounted for as a capital investment unrelated to the restart. At December 31, 1999, $119 million has been spent on the steam generator replacement.

The cost of electricity supplied to retail customers increased due to the outage of the two Cook Plant nuclear units since higher cost coal-fired generation and coal-based purchased power is being substituted for the unavailable low cost nuclear generation. With regulator approvals, actual replacement energy fuel costs that exceeded the costs reflected in billings were recorded as a regulatory asset under the Indiana and Michigan retail jurisdictional fuel cost recovery mechanisms.

On March 30, 1999, the IURC approved a settlement agreement that resolved all matters related to the recovery of replacement energy fuel costs and all outage/restart costs and issues during the extended outage of the Cook Plant. The settlement agreement provided for, among other things, a replacement fuel billing credit of $55 million, including interest, to Indiana retail customers' bills; the deferral of unrecovered fuel revenues accrued between September 9, 1997 and December 31, 1999, including the billing credit; the deferral of up to $150 million of jurisdictional restart related nuclear operation and maintenance costs in 1999 above the amount included in base rates; the amortization of the deferred fuel revenues and non-fuel operation and maintenance cost deferrals over a five-year period ending December 31, 2003; a freeze in base rates through December 31, 2003; and a fixed fuel recovery charge through March 1, 2004. The $55 million credit was applied to retail customers' bills during the months of July, August and September 1999.

On December 16, 1999, the MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases which resolves all issues related to the Cook Plant extended outage. The settlement agreement limits the Company's ability to increase base rates and freezes the power supply cost recovery factor until January 1, 2004; permits the deferral of up to $50 million in 1999 of jurisdictional non-fuel nuclear operation and maintenance expenses; authorizes the amortization of power supply cost recovery revenues accrued from September 9, 1997 to December 31, 1999 and non-fuel nuclear operation and maintenance cost deferrals over a five-year period ending December 31, 2003.

Expenditures to restart the Cook Plant units are estimated to total approximately $574 million. Through December 31, 1999, $373 million has been spent. The restart costs incurred in 1997 and 1998 were $6 and $78 million, respectively, and were recorded in other operation and maintenance expense. In 1999 the restart costs incurred were $289 million and were recorded in accordance with the Indiana and Michigan settlement agreements whereby $150 million and $50 million, respectively, of operation and maintenance costs were deferred in 1999 for amortization through December 31, 2003. The amortization of the non-fuel operation and maintenance restart cost deferrals through December 31, 1999 was $40 million. Consequently, maintenance and other operation expenses included $129 million of Cook restart expense for 1999. Also reflected in 1999 earnings is amortization of $38 million of fuel-related revenues. Restart costs incurred in 2000 will be accounted for as a current period operations and maintenance expense. At December 31, 1999, the unamortized balance of restart related operation and maintenance costs was $160 million and is included in the Company's regulatory assets. Also deferred as a regulatory asset at December 31, 1999 was $150 million of fuel-related revenues.

The costs of the extended outage and restart efforts will have a material adverse effect on future results of operations and possibly financial condition through 2003 and on cash flows through 2000. Management believes that the Cook Plant units will be successfully returned to service by April and September 2000. However, if for some unknown reason the units are not returned to service or their return is delayed significantly it would have an even greater adverse effect on future results of operations, cash flows and financial condition.

3. RATE MATTERS:

Transmission

The FERC issued orders 888 and 889 in April 1996 which required each public utility that owns or controls interstate transmission facilities to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The orders also require utilities to functionally unbundle their services, by requiring them to use their own transmission service tariffs in making off-system and third-party sales. As part of the orders, the FERC issued a pro-forma tariff which reflects the Commission's views on the minimum non-price terms and conditions for non-discriminatory transmission service. The FERC orders also allow a utility to seek recovery of certain prudently-incurred stranded costs that result from unbundled transmission service.

In July 1996, the AEP System companies filed an Open Access Transmission Tariff conforming with the FERC's pro-forma transmission tariff, subject to the resolution of certain pricing issues. The 1996 tariff incorporated transmission rates which were the result of a settlement of a pending rate case, but which were being collected subject to refund from certain customers who opposed the settlement and continued to litigate the reasonableness of the AEP System's transmission rates. On July 30, 1999, the FERC issued an order in the litigated rate case which would reduce AEP's rates for the affected customers below the settlement rate. The AEP System and certain of the affected customers sought rehearing of the FERC order. The Company made a provision in September 1999 for its share of the refund including interest.

On December 10, 1999, the AEP System companies filed a settlement agreement with the FERC resolving the issues on rehearing of the July 30, 1999 order. Under terms of the settlement, the AEP System will make refunds retroactive to September 7, 1993 to certain customers affected by the July 30, 1999 FERC order. The refunds will be made in two payments. The first payment was made on February 2, 2000 pursuant to a FERC order granting AEP's request to make interim refunds. The remainder will be paid after the FERC issues a final order and approves a compliance filing that the AEP System companies will make pursuant to the final order. In addition, a new rate was made effective January 1, 2000, subject to FERC approval, for all transmission service customers and a future rate was established to take effect upon the consummation of the AEP and Central and South West Corporation merger unless a superseding rate is made effective prior to the merger.

Retail

In December 1997, AEP Co., Inc. and Central and South West Corporation announced their plan to merge. As part of the regulatory approval process, the IURC and MPSC intervened in the FERC proceeding.

The IURC approved a settlement agreement related to the merger on April 26, 1999. The settlement agreement resulted from an investigation of the proposed merger initiated by the IURC. The terms of the settlement agreement provide for, among other things, a sharing of net merger savings for eight years through reductions in customers' bills of approximately $67 million over eight years following consummation of the merger; a one year extension through January 1, 2005 of a freeze in base rates; additional annual deposits of $6 million to the nuclear decommissioning trust fund for the Indiana jurisdiction for the years 2001 through 2003; quality-of-service standards; and participation in a regional transmission organization. As part of the settlement agreement, the IURC agreed not to oppose the merger in the FERC or SEC proceedings.

The MPSC has also approved a settlement agreement with the Company related to the pending merger. In approving the settlement agreement, the MPSC has agreed to not oppose the merger at the federal level. AEP has agreed to share net merger savings with Michigan customers as well as AEP shareowners for eight years; establish performance standards that will maintain or improve customer service and system reliability; join a regional transmission organization by December 31, 2000; and establish affiliate rules to protect consumers and promote fair competition. The Michigan jurisdictional customers' share of the net guaranteed merger savings is approximately $14 million over the eight years following the consummation of the merger. Once the merger is consummated, Michigan customers will receive their share of the net savings through billing credits of approximately 1 percent to 1.5 percent each year. The credits will continue for at least eight years and will not be affected by any changes to the current regulatory structure in Michigan.

4. EFFECTS OF REGULATION AND PHASE-IN PLANS:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred income) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. Among other things, application of SFAS 71 requires that the Company's regulated rates be cost-based and the recovery of regulatory assets probable. Management has reviewed the evidence currently available and concluded that the Company continues to meet the requirements to apply SFAS 71. In the event a portion of the Company's business no longer met those requirements net regulatory assets would have to be written off for that portion of the business and assets attributable to that portion of the business would have to be tested for possible impairment and, if required, an impairment loss recorded unless the net regulatory assets and impairment losses are recoverable as a stranded cost.

Recognized regulatory assets and liabilities are comprised of the following at:

	December 31, 1999	December 31, 1998
	(in thousands)	
Regulatory Assets:		
Amounts Due From Customers for Future Income Taxes	$236,783	$259,641
Cook Plant Restart Costs	160,000	-
Unrecovered Fuel and Purchased Power	150,004	65,308
Department of Energy Decontamination and Decommissioning Assessment	35,238	38,898
Nuclear Refueling Outage Cost Levelization	9,150	17,630
Unamortized Loss On Reacquired Debt	14,780	16,434
Other	18,855	23,564
Total Regulatory Assets	$624,810	$421,475
Regulatory Liabilities:		
Deferred Investment Tax Credits	$121,627	$129,779
Other*	17,238	16,507
Total Regulatory Liabilities	$138,865	$146,286

* Included in Deferred Credits on Consolidated Balance Sheets.

The Rockport Plant consists of two 1,300 mw coal-fired units. I&M and AEP Generating Company (AEGCo), an affiliate, each own 50% of one unit (Rockport 1) and each lease a 50% interest in the other unit (Rockport 2) from unaffiliated lessors under an operating lease. The gain on the sale and leaseback of Rockport 2 was deferred and is being amortized, with related taxes and investment tax credits, over the initial lease term which expires in 2022.

At January 1, 1997 rate phase-in plan deferrals existed for the Rockport Plant. Rate phase-in plans in the Company's Indiana and FERC jurisdictions provided for the recovery and straight-line amortization of deferred Rockport Plant Unit 1 costs over ten years beginning in 1987. In 1997 the amortization and recovery of the deferred Rockport Plant Unit 1 Phase-in Plan costs were completed. During the recovery period net income was unaffected by the recovery of the phase-in deferrals. Amortization was $11.9 million in 1997.

5. COMMITMENTS AND CONTINGENCIES:

Construction and Other Commitments

Substantial construction commitments have been made to support the Company's utility operations and are estimated to be $329 million for 2000-2002.

Long-term fuel supply contracts contain clauses that provide for periodic price adjustments. The fuel supply contracts are for various terms, the longest of which extends to 2014, and contain various clauses that would release the Company from its obligation under certain force majeure conditions. The Michigan and Indiana retail jurisdictions, under the terms of settlement agreements have suspended the operation of fuel clause mechanisms that provide for recovery of changes in the cost of fuel with the regulators' review and approval until January 2004 and March 2004, respectively.

The Company is committed under unit power agreements to purchase all of AEGCo's share, 50% of the 2,600 mw Rockport Plant capacity, unless it is sold to other utilities. AEGCo had a long-term unit power agreement which expired December 31, 1999 for the sale of 455 mw to an unaffiliated utility. Revenues received by AEGCo under this agreement were $64 million in 1999. An agreement between AEGCo and another affiliate provides for the sale of 390 mw of capacity to that affiliate through 2004. Effective January 1, 2000, I&M is required to purchase 910 mw of Rockport Plant capacity from AEGCo.

The Company sells under contract up to 250 mw of its Rockport Plant capacity to an unaffiliated utility. The contract expires in 2009.

Nuclear Plant

The operation of a nuclear facility involves special risks, potential liabilities, and specific regulatory and safety requirements. Should a nuclear incident occur at any nuclear power plant facility in the United States (U.S.), the resultant liability could be substantial. By agreement I&M is partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery in rates is not possible, results of operations, cash flows and financial condition would be negatively affected.

Nuclear Incident Liability

Public liability is limited by law to $9.9 billion should an incident occur at any licensed reactor in the U.S. Commercially available insurance provides $200 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S. the remainder of the liability would be provided by a deferred premium assessment of $88 million on each licensed reactor payable in annual installments of $10 million. As a result, I&M could be assessed $176 million per nuclear incident payable in annual installments of $20 million. The number of incidents for which payments could be required is not limited.

Nuclear insurance pools and other insurance policies provide $3 billion of property damage, decommissioning and decontamination coverage for Cook Plant. Additional insurance provides coverage for extra costs resulting from a prolonged accidental Cook Plant outage. Some of the policies have deferred premium provisions which could be triggered by losses in excess of the insurer's resources. The losses could result from claims at the Cook Plant or certain other unaffiliated nuclear units. The Company could be assessed up to $23 million annually under these policies.

SNF Disposal

Federal law provides for government responsibility for permanent SNF disposal and assesses nuclear plant owners fees for SNF disposal. A fee of one mill per kilowatthour for fuel consumed after April 6, 1983 is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $199 million for fuel consumed prior to April 7, 1983 have been recorded as long-term debt. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 1999, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon approximate the liability.

Decommissioning and Low Level Waste Accumulation Disposal

Decommissioning costs are being accrued over the service life of the Cook Plant. The licenses to operate the two nuclear units expire in 2014 and 2017. After expiration of the licenses the plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs ranges from $700 million to $1,152 million in 1997 nondiscounted dollars. The wide range is caused by variables in assumptions including the estimated length of time SNF may need to be stored at the plant site subsequent to ceasing operations. This, in turn, depends on future developments in the federal government's SNF disposal program. Continued delays in the federal fuel disposal program can result in increased decommissioning costs. The Company is recovering estimated decommissioning costs in its three rate-making jurisdictions based on at least the lower end of the range in the most recent decommissioning study at the time of the last rate proceeding. The Company records decommissioning costs in other operation expense and records a noncurrent liability equal to the decommissioning cost recovered in rates; such amounts were $28 million in 1999, $29 million in 1998 and $28 million in 1997. Decommissioning costs recovered from customers are deposited in external trusts. In 1999 the Company also deposited in the decommissioning trust $4 million related to a special regulatory commission approved funding method. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. During 1999 and 1998 the Company withdrew $8 million and $3 million, respectively, from the trust funds for decommissioning of the original steam generators removed from Unit 2. At December 31, 1999 and 1998, the Company has recognized a decommissioning liability of $501 million and $446 million, respectively.

Federal EPA Complaint and Notice of Violation

Under the Clean Air Act, if a fossil plant undertakes a major modification that directly results in an emissions increase, permitting requirements might be triggered and the plant may be required to install additional pollution control technology. This requirement does not apply to activities such as routine maintenance, replacement of degraded equipment or failed components, or other repairs needed for the reliable, safe and efficient operation of the plant.

On November 3, 1999, the Department of Justice, at the request of the U.S. Environmental Protection Agency (Federal EPA), filed a complaint in the U.S. District Court for the Southern District of Ohio that alleges the Company made modifications to generating units at its Tanners Creek Plant over the course of the past 25 years that extend unit operating lives or increase unit generating capacity without a preconstruction permit in violation of the Clean Air Act. Federal EPA also issued a Notice of Violation to the Company and other AEP companies alleging violations at certain AEP Plants. A number of unaffiliated utilities also received Notices of Violation, complaints or administrative orders.

The states of New Jersey, New York and Connecticut were subsequently granted leave to intervene in the Federal EPA's action against the Company under the Clean Air Act. On November 18, 1999, a number of environmental groups filed a lawsuit against power plants owned by the Company and its AEP System affiliates alleging similar violations to those in the Federal EPA complaint and Notices of Violation. This action has been consolidated with the Federal EPA action.

The Clean Air Act authorizes civil penalties of up to $27,500 per day per violation at each generating unit ($25,000 per day prior to January 30, 1997). Civil penalties, if ultimately imposed by the court, and the cost of any required new pollution control equipment, if the court accepts all of Federal EPA's contentions, could be substantial.

Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense of this matter.

In the event the Company does not prevail, any capital and operating costs of additional pollution control equipment that may be required as well as any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered through regulated rates or the future market prices of electricity if generation is deregulated.

Litigation

The Internal Revenue Service (IRS) agents auditing the AEP System's consolidated federal income tax returns requested a ruling from their National Office that certain interest deductions claimed by the Company relating to AEP's corporate owned life insurance (COLI) program should not be allowed. As a result of a suit filed in U.S. District Court (discussed below) this request for ruling was withdrawn by the IRS agents. Adjustments have been or will be proposed by the IRS disallowing COLI interest deductions for taxable years 1991-96. A disallowance of the COLI interest deductions through December 31, 1999 would reduce earnings by approximately $66 million (including interest).

The Company made payments of taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of any additional above market rate interest on the contested amount. The payments to the IRS are included on the Consolidated Balance Sheets in other property and investments pending the resolution of this matter. The Company is seeking refunds through litigation of all amounts paid plus interest.

In order to resolve this issue, the Company filed suit against the United States in the U.S. District Court for the Southern District of Ohio in March 1998. In 1999 a U.S. Tax Court judge decided in the Winn-Dixie Stores v. Commissioner case that a corporate taxpayer's COLI interest deduction should be disallowed. Notwithstanding the Tax Court's decision in Winn-Dixie, management has made no provision for any possible adverse earnings impact from this matter because it believes, and has been advised by outside counsel, that it has a meritorious position and will vigorously pursue its lawsuit. In the event the resolution of this matter is unfavorable, it will have a material adverse impact on results of operations, cash flows and possibly financial condition.

The Company is involved in a number of other legal proceedings and claims. While management is unable to predict the ultimate outcome of litigation, it is not expected that the resolution of these matters will have a material adverse effect on the results of operations, cash flows and financial condition.

6. SUBSEQUENT EVENT - NOx REDUCTIONS (March 3, 2000):

On March 3, 2000, the U.S. Court of Appeals for the District of Columbia Circuit (Appeals Court) issued a decision generally upholding Federal EPA's final rule (the NOx rule) that requires substantial reductions in nitrogen oxide (NOx) emissions in 22 eastern states, including the states in which the Company's generating plants are located. A number of utilities, including the AEP System companies, had filed petitions seeking a review of the final rule in the Appeals Court. On May 25, 1999, the Appeals Court had indefinitely stayed the requirement that states develop revised air quality programs to impose the NOx reductions but did not, however, stay the final compliance date of May 1, 2003.

On April 30, 1999, Federal EPA took final action with respect to petitions filed by eight northeastern states pursuant to the Clean Air Act (Section 126 Rule). The rule approved portions of the states' petitions and imposed NOx reduction requirements on AEP System generating units which are approximately equivalent to the reductions contemplated by the NOx Rule. The AEP

System companies with generating plants, as well as other utility companies, filed a petition in the Appeals Court seeking review of Federal EPA's approval of the northeastern states' petitions. In 1999, three additional northeastern states and the District of Columbia filed petitions with Federal EPA similar to those originally filed by the eight northeastern states. Since the petitions relied in part on compliance with an 8-hour ozone standard remanded by the Appeals Court in May 1999, Federal EPA indicated its intent to decouple compliance with the 8-hour standard and issue a revised rule.

On December 17, 1999, Federal EPA issued a revised Section 126 Rule not based on the 8-hour standard and ordered 392 industrial facilities, including certain coal-fired generating plants owned by the Company, to reduce their NOx emissions by May 1, 2003. This rule approves portions of the petitions filed by four northeastern states which contend that their failure to meet Federal EPA smog standards is due to emissions from upwind states' industrial and coal-fired generating facilities.

Preliminary estimates indicate that compliance with the NOx rule upheld by the Appeals Court could result in required capital expenditures of approximately $202 million for the Company. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the Company's preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless such costs are recovered from customers through regulated rates and/or reflected in the future market price of electricity if generation is deregulated, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

7. RELATED PARTY TRANSACTIONS:

Benefits and costs of the AEP System's generating plants are shared by members of the AEP Power Pool of which the Company is a member. Under the terms of the AEP System Interconnection Agreement, capacity charges and credits are designed to allocate the cost of the AEP System's capacity among the AEP Power Pool members based on their relative peak demands and generating reserves. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The Company is a net supplier to the AEP Power Pool and, therefore, receives capacity credits from the AEP Power Pool.

Operating revenues include revenues for capacity and energy supplied to the AEP Power Pool as follows:

	Year Ended December 31,		
	1999	1998	1997
	(in thousands)		
Capacity Revenues	$42,575	$33,011	$ 53,282
Energy Revenues	8,049	4,550	64,861
Total	$50,624	$37,561	$118,143

Purchased power expense includes charges of $112.3 million in 1999, $125.2 million in 1998 and $51 million in 1997 for energy received from the AEP Power Pool.

The AEP Power Pool allocates operating revenues, purchased power expense and nonoperating income to the Company. Power marketing and trading operations, which are described in Note 1, are conducted by the AEP Power Pool and shared with the Company. Net trading transactions are included in operating revenues if the trading transactions are within the AEP Power Pool's traditional marketing area and are recorded in nonoperating income if the net trading transactions are outside of the AEP Power Pool's traditional marketing area. The total amount allocated by the AEP Power Pool, which includes amounts for power marketing and trading transactions, are as follows:

	Year Ended December 31,		
	1999	1998	1997
	(in thousands)		
Operating Revenues	$81,659	$124,973	$74,895
Purchased Power Expense	66,285	71,588	15,415
Nonoperating Income (Loss)	2,104	(7,122)	(61)

The cost of Rockport Plant power purchased from AEGCo, an affiliated company that is not a member of the AEP Power Pool, was included in purchased power expense in the amounts of $88.1 million, $86.2 million and $87.5 million in 1999, 1998 and 1997, respectively.

The cost of power purchased from Ohio Valley Electric Corporation, an affiliated company that is not a member of the AEP Power Pool, was included in purchased power expense in the amounts of $10.2 million, $14.3 million and $11 million in 1999, 1998 and 1997, respectively.

The Company operates the Rockport Plant and bills AEGCo for its share of operating costs.

The Company participates in the AEP System Transmission Equalization Agreement along with other AEP System electric operating utility companies. This agreement combines certain AEP System companies' investments in transmission facilities and shares the costs of ownership in proportion to the AEP System companies' respective peak demands. Pursuant to the terms of the agreement, since the Company's relative investment in transmission facilities is greater than its relative peak demand, other operation expense includes equalization credits of $43.9 million, $44.1 million and $46.1 million in 1999, 1998 and 1997, respectively.

Revenues from providing barging services were recorded in nonoperating income as follows:

	Year Ended December 31,		
	1999	1998	1997
	(in thousands)		
Affiliated Companies	$28,100	$23,494	$24,427
Unaffiliated Companies	15,700	12,490	8,383
Total	$43,800	$35,984	$32,810

American Electric Power Service Corporation (AEPSC) provides certain managerial and professional services to AEP System companies including the Company. The costs of the services are billed by AEPSC to its affiliated companies on a direct-charge basis whenever possible and on reasonable bases of proration for shared services. The billings for services are made at cost and include no compensation for the use of equity capital, which is furnished to AEPSC by AEP Co., Inc. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered. AEPSC and its billings are subject to the regulation of the SEC under the 1935 Act.

8. STAFF REDUCTIONS:

During 1998 an internal evaluation of the power generation organization was conducted with a goal of developing an optimum organizational structure for a competitive generation market. The study was completed in October 1998. In addition, a review of energy delivery staffing levels was conducted in 1998. As a result approximately 80 power generation and energy delivery positions were identified for elimination.

A provision for severance costs totaling $3.7 million was recorded in December 1998 for reductions in power generation and energy delivery staffs and was charged to maintenance and other operation expense in the Consolidated Statements of Income. The power generation and energy delivery staff reductions were made in the first quarter of 1999. The amount of severance benefits paid was not significantly different from the amount accrued.

9. BENEFIT PLANS:

The Company and its subsidiaries participate in the AEP System qualified pension plan, a defined benefit plan which covers all employees. Net pension (credits) costs for the years ended December 31, 1999, 1998 and 1997 were $(1.3) million, $2.1 million and $2.1 million, respectively.

Postretirement benefits other than pensions are provided for retired employees for medical and death benefits under an AEP System plan. The Company's annual accrued costs for 1999, 1998 and 1997 were $13.7 million, $12 million and $11.5 million, respectively.

A defined contribution employee savings plan required that the Company make contributions to the plan totaling $4 million each year in 1999, 1998 and 1997.

10. SEGMENT INFORMATION:

Effective December 31, 1998, the Company adopted SFAS 131, "Disclosures about Segments of an Enterprise and Related Information". The Company has one reportable segment, a regulated vertically integrated electricity generation and energy delivery business. All other activities are insignificant. The Company's operations are managed on an integrated basis because of the substantial impact of bundled cost-based rates and regulatory oversight on business processes, cost structures and operating results. Aggregated in the regulated electric utility segment is the power marketing and trading activities that are discussed in Note 1. For the years ended December 31, 1999, 1998 and 1997, all revenues are derived in the U.S.

11. FINANCIAL INSTRUMENTS, CREDIT AND RISK MANAGEMENT:

The Company is subject to market risk as a result of changes in electricity commodity prices and interest rates. The Company through its membership in the AEP Power Pool participates in a power marketing and trading operation that manages the exposure to electricity commodity price movements using physical forward purchase and sale contracts at fixed and variable prices, and financial derivative instruments including exchange traded futures and options, over-the-counter options, swaps and other financial derivative contracts at both fixed and variable prices. Physical forward electricity contracts within the AEP Power Pool's traditional marketing area are recorded on a net basis as operating revenues in the month when the physical contract settles. The Company's share of the net gains from these regulated transactions for the year ended December 31, 1999 and 1998 was $4 million and $21 million, respectively. These activities were not material in 1997.

Non-regulated physical forward electricity contracts outside the AEP Power Pool's traditional marketing area and all financial electricity trading transactions where the underlying physical commodity is outside AEP's traditional marketing area are recorded in nonoperating income. Non-regulated open trading contracts are accounted for on a mark-to-market basis in nonoperating income. The Company's share of the net gains (losses) from these non-regulated trading transactions for the year ended December 31, 1999 and 1998 was $2 million and $(7) million, respectively.

In the first quarter of 1999 the Company adopted EITF 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." The EITF requires that all energy trading contracts be marked-to-market. The effect on the consolidated Statements of Income of marking open trading contracts to market is deferred as regulatory assets or liabilities for those open trading transactions within the AEP Power Pool's marketing area that are included in the cost of service on a settlement basis for rate-making purposes. The unrealized mark-to-market gains and losses from trading of financial instruments are reported as assets and liabilities, respectively. These activities were not material in prior periods.

The Company is exposed to risk from changes in interest rates primarily due to short-term and long-term borrowings used to fund its business operations. The debt portfolio has both fixed and variable interest rates with terms from one day to 39 years and an average duration of five years at December 31, 1999. A near term change in interest rates should not materially affect results of operations or financial position since the Company would not expect to liquidate its entire debt portfolio in a one year holding period.

Market Valuation

The book value of cash and cash equivalents, accounts receivable, short-term debt and accounts payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the Company's best estimate of its fair value.

The book value amounts and fair values of the Company's significant financial instruments at December 31, 1999 and 1998 are summarized in the following table. The fair values of long-term debt and preferred stock are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments of the same remaining maturities. The fair value of those financial instruments that are marked-to-market are based on management's best estimates using over-the-counter quotations, exchange prices, volatility factors and valuation methodology. The estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange.

	1999		1998	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)		(in thousands)	
Non-Derivatives				
Long-term Debt	$1,324,326	$1,283,300	$1,175,789	$1,235,200
Preferred Stock	64,945	63,500	68,445	72,600

Derivatives

	1999			1998		
	Notional Amount	Fair Value	Average Fair Value	Notional Amount	Fair Value	Average Fair Value
	(Dollars in thousands)					
Trading Assets						
	GWH			GWH		
Electric						
NYMEX Futures and Options	43	$ 340	$ 171	-	$ -	$ -
Physicals	13,592	112,830	99,621	11,097	8,700	7,700
Options	1,213	8,010	12,125	734	6,300	15,300
Swaps	35	76	61	52	600	200
Trading Liabilities						
	GWH			GWH		
Electric						
NYMEX Futures and Options	-	$ -	$ -	133	$(1,300)	$ (300)
Physicals	14,620	(105,169)	(95,948)	10,932	(9,400)	(8,800)
Options	1,742	(8,391)	(11,010)	557	(5,700)	(15,200)
Swaps	35	(70)	(58)	93	(1,400)	(400)

Credit and Risk Management

In addition to market risk associated with price movements, the Company through the AEP Power Pool is also subject to the credit risk inherent in its risk management activities. Credit risk refers to the financial risk arising from commercial transactions and/or the intrinsic financial value of contractual agreements with trading counter parties, by which there exists a potential risk of nonperformance. The AEP Power Pool has established and enforced credit policies that minimize this risk. The AEP Power Pool accepts as counter parties to forwards, futures, and other derivative contracts primarily those entities that are classified as Investment Grade, or those that can be considered as such due to the effective placement of credit enhancements and/or collateral agreements. Investment grade is the designation given to the four highest debt rating categories (i.e., AAA, AA, A, BBB) of the major rating services, e.g., ratings BBB- and above at Standard & Poor's and Baa3 and above at Moody's. When adverse market conditions have the potential to negatively affect a counter party's credit position, the AEP Power Pool requires further credit enhancements to mitigate risk. Since the formation of the power marketing and trading business in July of 1997, the Company has experienced no significant losses due to the credit risk associated with risk management activities; furthermore, the Company does not anticipate any future material effect on its results of operations, cash flow or financial condition as a result of counter party nonperformance.

Nuclear Trust Funds Recorded at Market Value

The Nuclear Decommissioning and SNF Disposal Trust Fund investments are recorded at market value in accordance with SFAS 115 and consist of tax-exempt municipal bonds and other securities.

At December 31, 1999 and 1998 the fair values of trust fund investments were $708 million and $648 million, respectively. Accumulated gross unrealized holding gains were $78 million and $65 million and accumulated gross unrealized holding losses were $6.7 million and $1.1 million at December 31, 1999 and 1998, respectively. The change in market value in 1999, 1998 and 1997 was a net unrealized holding gain of $7.5 million, $24 million and $19.1 million, respectively.

The trust fund investments' cost basis by security type were:

	December 31,	
	1999	1998
	(in thousands)	
Tax-Exempt Bonds	$350,798	$326,239
Equity Securities	116,110	95,854
Treasury Bonds	72,927	71,194
Corporate Bonds	13,162	10,661
Cash, Cash Equivalents and Interest Accrued	83,129	80,065
Total	$636,126	$584,013

Proceeds from sales and maturities of securities of $226 million during 1999 resulted in $5.8 million of realized gains and $5.3 million of realized losses. Proceeds from sales and maturities of securities of $225 million during 1998 resulted in $8.2 million of realized gains and $2.8 million of realized losses. Proceeds from sales and maturities of securities of $147.3 million during 1997 resulted in $3.9 million of realized gains and $1.4 million of realized losses. The cost of securities for determining realized gains and losses is original acquisition cost including amortized premiums and discounts.

At December 31, 1999, the year of maturity of trust fund investments, other than equity securities, was:

	(in thousands)
2000	$120,630
2001-2004	173,851
2005-2009	181,860
After 2009	43,675
Total	$520,016

12. FEDERAL INCOME TAXES:

The details of federal income taxes as reported are as follows:

	Year Ended December 31,		
	1999	1998	1997
	(in thousands)		
Charged (Credited) to Operating Expenses (net):			
Current	$(60,238)	$ 38,165	$ 75,442
Deferred	85,345	21,073	3,088
Deferred Investment Tax Credits	(7,547)	(7,593)	(7,786)
Total	17,560	51,645	70,744
Charged (Credited) to Nonoperating Income (net):			
Current	1,529	(594)	3,287
Deferred	382	(3,168)	834
Deferred Investment Tax Credits	(605)	(673)	(642)
Total	1,306	(4,435)	3,479
Total Federal Income Taxes as Reported	$ 18,866	$ 47,210	$ 74,223

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before federal income taxes by the statutory tax rate, and the amount of federal income taxes reported.

	Year Ended December 31,		
	1999	1998 (in thousands)	1997
Net Income	$ 32,776	$ 96,628	$146,740
Federal Income Taxes	18,866	47,210	74,223
Pre-tax Book Income	$ 51,642	$143,838	$220,963
Federal Income Tax on Pre-tax Book Income at Statutory Rate (35%)	$18,075	$50,343	$77,337
Increase (Decrease) in Federal Income Tax Resulting From the Following Items:			
Depreciation	19,966	17,257	14,082
Corporate Owned Life Insurance	594	(3,263)	(3,348)
Nuclear Fuel Disposal Costs	(3,347)	(3,397)	(3,286)
AFUDC	(2,174)	(2,184)	(1,987)
Investment Tax Credits (net)	(8,152)	(8,266)	(8,428)
Other	(6,096)	(3,280)	(147)
Total Federal Income Taxes as Reported	$18,866	$47,210	$74,223
Effective Federal Income Tax Rate	36.5%	32.8%	33.6%

The following tables show the elements of the net deferred tax liability and the significant temporary differences giving rise to such deferrals:

	December 31,	
	1999	1998
	(in thousands)	
Deferred Tax Assets	$ 231,329	$ 226,118
Deferred Tax Liabilities	(853,486)	(785,406)
Net Deferred Tax Liabilities	$(622,157)	$(559,288)
Property Related Temporary Differences	$(436,162)	$(460,077)
Amounts Due From Customers For Future Federal Income Taxes	(61,311)	(69,102)
Deferred State Income Taxes	(61,700)	(62,302)
Deferred Gain on Sale and Leaseback of Rockport Plant Unit 2	29,752	31,049
Accrued Nuclear Decommissioning Expense	32,097	29,930
Deferred Fuel and Purchased Power	(52,713)	(22,737)
Deferred Cook Plant Restart Costs	(56,000)	-
All Other (net)	(16,120)	(6,049)
Net Deferred Tax Liabilities	$(622,157)	$(559,288)

The Company and its subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System.

The allocation of the AEP System's current consolidated federal income tax to the AEP System companies is in accordance with SEC rules under the 1935 Act. These rules permit the allocation of the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the parent company, AEP Co., Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidated group.

The AEP System has settled with the IRS all issues from the audits of the consolidated federal income tax returns for the years prior to 1991. Returns for the years 1991 through 1996 are presently being audited by the IRS. With the exception of interest deductions related to COLI, which are discussed under the heading "Litigation" in Note 5, management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

13. CUMULATIVE PREFERRED STOCK:

At December 31, 1999, authorized shares of cumulative preferred stock were as follows:

Par Value	Shares Authorized
$100	2,250,000
25	11,200,000

The cumulative preferred stock is callable at the price indicated below plus accrued dividends. The involuntary liquidation preference is par value. Unissued shares of the cumulative preferred stock may or may not possess mandatory redemption characteristics upon issuance.

A. Cumulative Preferred Stock Not Subject to Mandatory Redemption:

Series	Call Price December 31, 1999	Par Value	Number of Shares Redeemed Year Ended December 31, 1999	1998	1997	Shares Outstanding December 31, 1999	Amount December 31, 1999 (in thousands)	1998
4-1/8%	$106.125	$100	97	771	59,760	59,139	$5,914	$5,924
4.56%	102	100	150	650	44,788	14,412	1,441	1,456
4.12%	102.728	100	-	200	20,869	18,931	1,893	1,893
							$9,248	$9,273

B. Cumulative Preferred Stock Subject to Mandatory Redemption:

Series(a)	Par Value	Number of Shares Redeemed Year Ended December 31, 1999	1998	1997	Shares Outstanding December 31, 1999	Amount December 31, 1999 (in thousands)	1998
5.90% (b)	$100	15,000	-	233,000	152,000	$15,200	$16,700
6-1/4%(b)	100	10,000	-	97,500	192,500	19,250	20,250
6.30% (b)	100	-	-	217,550	132,450	13,245	13,245
6-7/8%(c)	100	10,000	-	117,500	172,500	17,250	18,250
						$64,945	$68,445

(a) Not callable until after 2002. There are no aggregate sinking fund provisions through 2002. Sinking fund provisions require the redemption of 15,000 shares in 2003 and 67,500 shares in 2004.
(b) Commencing in 2004 and continuing through 2008 the Company may redeem, at $100 per share, 20,000 shares of the 5.90% series, 15,000 shares of the 6-1/4% series and 17,500 shares of the 6.30% series outstanding under sinking fund provisions at its option and all remaining outstanding shares must be redeemed not later than 2009. Shares redeemed in 1999 and 1997 may be applied to meet the sinking fund requirement.
(c) Commencing in 2003 and continuing through the year 2007, a sinking fund will require the redemption of 15,000 shares each year and the redemption of the remaining shares outstanding on April 1, 2008, in each case at $100 per share. Shares redeemed in 1999 and 1997 may be applied to meet the sinking fund requirement.

14. LONG-TERM DEBT AND LINES OF CREDIT:

Long-term debt by major category was outstanding as follows:

	December 31, 1999	December 31, 1998
	(in thousands)	
First Mortgage Bonds	$ 356,820	$ 466,330
Installment Purchase Contracts	309,568	309,418
Senior Unsecured Notes	297,282	48,559
Other Long-term Debt (a)	199,259	190,192
Junior Debentures	161,397	161,290
	1,324,326	1,175,789
Less Portion Due Within One Year	198,000	35,000
Total	$1,126,326	$1,140,789

(a) Represents a SNF disposal liability including interest accrued payable to the Department of Energy. See Note 5.

First mortgage bonds outstanding were as follows:

% Rate	Due	December 31, 1999	December 31, 1998
		(in thousands)	
7.30	1999 - December 15	$ -	$ 35,000
6.40	2000 - March 1	48,000	48,000
7.63	2001 - June 1	40,000	40,000
7.60	2002 - November 1	50,000	50,000
7.70	2002 - December 15	40,000	40,000
6.80	2003 - July 1	-	20,000
6.55	2003 - October 1	-	20,000
6.10	2003 - November 1	30,000	30,000
6.55	2004 - March 1	-	25,000
8.50	2022 - December 15	75,000	75,000
7.35	2023 - October 1	20,000	20,000
7.20	2024 - February 1	30,000	40,000
7.50	2024 - March 1	25,000	25,000
Unamortized Discount (net)		(1,180)	(1,670)
		356,820	466,330
Less Portion Due Within One Year		48,000	35,000
Total		$308,820	$431,330

Certain indentures relating to the first mortgage bonds contain improvement, maintenance and replacement provisions requiring the deposit of cash or bonds with the trustee, or in lieu thereof, certification of unfunded property additions.

Installment purchase contracts have been entered into in connection with the issuance of pollution control revenue bonds by governmental authorities as follows:

% Rate	Due	December 31, 1999	December 31, 1998
		(in thousands)	
City of Lawrenceburg, Indiana:			
7.00	2015 - April 1	$ 25,000	$ 25,000
5.90	2019 - November 1	52,000	52,000
City of Rockport, Indiana:			
(a)	2014 - August 1	50,000	50,000
7.60	2016 - March 1	40,000	40,000
6.55	2025 - June 1	50,000	50,000
(b)	2025 - June 1	50,000	50,000
City of Sullivan, Indiana:			
5.95	2009 - May 1	45,000	45,000
Unamortized Discount		(2,432)	(2,582)
		309,568	309,418
Less Portion Due Within One Year		50,000	-
Total		$259,568	$309,418

(a) A variable interest rate is determined weekly. The average weighted interest rate was 3.2% for 1999 and 4.1% for 1998.

(b) An adjustable interest rate can be a daily, weekly, commercial paper or term rate as designated by the Company. A weekly rate was selected which ranged from 2.2% to 5.6% in 1999 and from 2.7% to 4.3% in 1998 and averaged 3.2% and 3.6% during 1999 and 1998, respectively.

Under the terms of certain installment purchase contracts, the Company is required to pay amounts sufficient to enable the cities to pay interest on and the principal (at stated maturities and upon mandatory redemption) of related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain generating plants. On the two variable rate series the principal is payable at the stated maturities or on the demand of the bondholders at periodic interest adjustment dates which occur weekly. The variable rate bonds due in 2014 are supported by a bank letter of credit which expires in 2002. I&M has agreements that provide for brokers to remarket the adjustable rate bonds due in 2025 tendered at interest adjustment dates. In the event certain bonds cannot be remarketed, I&M has a standby bond purchase agreement with a bank that provides for the bank to purchase any bonds not remarketed. The purchase agreement expires in 2000. Accordingly, the variable and adjustable rate installment purchase contracts have been classified for repayment purposes based on the expiration dates of the standby purchase agreement and the letter of credit.

Senior unsecured notes outstanding were as follows:

% Rate	Due	December 31, 1999	December 31, 1998
		(in thousands)	
(a)	2000 - November 22	$100,000	$ -
6-7/8	2004 - July 1	150,000	-
6.45	2008 - November 10	50,000	50,000
Unamortized Discount		(2,718)	(1,441)
		297,282	48,559
Less Portion Due Within One Year		100,000	-
Total		$197,282	$48,559

(a) A floating interest rate is determined monthly. The rate on December 31, 1999 was 7.1%.

Junior debentures are composed of the following:

% Rate	Due	December 31, 1999	December 31, 1998
		(in thousands)	
8.00	2026 - March 31	$ 40,000	$ 40,000
7.60	2038 - June 30	125,000	125,000
Unamortized Discount		(3,603)	(3,710)
Total		$161,397	$161,290

Interest may be deferred and payment of principal and interest on the junior debentures is subordinated and subject in right to the prior payment in full of all senior indebtedness of the Company.

At December 31, 1999, future annual long-term debt payments are as follows:

	Amount (in thousands)
2000	$ 198,000
2001	40,000
2002	140,000
2003	30,000
2004	150,000
Later Years	776,259
Total Principal Amount	1,334,259
Unamortized Discount	(9,933)
Total	$1,324,326

Short-term debt borrowings are limited by provisions of the 1935 Act to $500 million. Lines of credit are shared with AEP System companies and at December 31, 1999 were available in the amounts of $1,056 million. The short-term lines of credit require the payment of facility fees and do not require compensating balances. At December 31, 1999 and 1998, outstanding short-term debt consisted of commercial paper with year-end weighted average interest rates of 6.6% and 6.2%, respectively.

15. LEASES:

Leases of property, plant and equipment are for periods of up to 35 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases. The Company is leasing 50% of the 1,300 mw Rockport 2 generating unit under an operating lease. The lease has 23 years remaining and total minimum lease payments of $1.7 billion.

Lease rentals for both operating and capital leases are generally charged to operating expenses in accordance with rate-making treatment. The components of rental costs are as follows:

	Year Ended December 31, 1999	1998	1997
		(in thousands)	
Lease Payments on Operating Leases	$ 81,611	$ 88,297	$ 92,067
Amortization of Capital Leases	11,320	10,717	42,882
Interest on Capital Leases	9,338	10,302	9,737
Total Lease Rental Costs	$102,269	$109,316	$144,686

Properties under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31, 1999	December 31, 1998
	(in thousands)	
Electric Utility Plant Under Capital Leases:		
Production Plant	$ 8,348	$ 8,850
Transmission Plant	4	-
Distribution Plant	14,645	14,645
General Plant:		
Nuclear Fuel (net of amortization)	108,140	103,939
Other Plant	59,150	60,002
Total Electric Utility Plant Under Capital Leases	190,287	187,436
Accumulated Amortization	35,176	33,948
Net Electric Utility Plant Under Capital Leases	155,111	153,488
Other Property Under Capital Leases	40,213	37,672
Accumulated Amortization	7,359	4,733
Net Other Property Under Capital Leases	32,854	32,939
Net Properties Under Capital Leases	$187,965	$186,427
Capital Lease Obligations*:		
Noncurrent Liability	$176,893	$176,760
Liability Due Within One Year	11,072	9,667
Total Capital Lease Obligations	$187,965	$186,427

* Represents the present value of future minimum lease payments.

The noncurrent portion of capital lease obligations is included in other noncurrent liabilities on the Consolidated Balance Sheets. Properties under operating leases and related obligations are not included on the Consolidated Balance Sheets.

Future minimum lease payments consisted of the following at December 31, 1999:

	Capital Leases	Non-Cancelable Operating Leases
	(in thousands)	
2000	$ 15,186	$ 100,288
2001	13,535	99,061
2002	16,116	97,341
2003	10,259	97,207
2004	8,641	96,395
Later Years	38,808	1,528,873
Total Future Minimum Lease Payments	102,545 (a)	$2,019,165
Less Estimated Interest Element	22,720	
Estimated Present Value of Future Minimum Lease Payments	79,825	
Unamortized Nuclear Fuel	108,140	
Total	$187,965	

(a) Excludes nuclear fuel rentals which are paid in proportion to heat produced and carrying charges on the unamortized nuclear fuel balance. There are no minimum lease payment requirements for leased nuclear fuel.

16. COMMON SHAREHOLDER'S EQUITY:

Mortgage indentures, charter provisions and orders of regulatory authorities place various restrictions on the use of retained earnings for the payment of cash dividends on common stock. At December 31, 1999, $5.9 million of retained earnings were restricted. Regulatory approval is required to pay dividends out of paid-in capital.

In 1999, 1998 and 1997 net changes to paid-in capital of $134,000, $133,000 and $1,200,000 respectively, represented gains and expenses associated with cumulative preferred stock transactions.

17. SUPPLEMENTARY INFORMATION:

	Year Ended December 31, 1999	1998	1997
	(in thousands)		
Cash was paid (received) for:			
Interest (net of capitalized amounts)	$ 78,703	$66,313	$ 62,274
Income Taxes	(71,395)	36,413	120,212
Noncash Acquisitions Under Capital Leases	10,852	9,658	111,395

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION:

Quarterly Periods Ended	Operating Revenues	Operating Income	Net Income (Loss)
	(in thousands)		
1999			
March 31	$334,113	$38,838	$20,070
June 30	336,553	26,966	9,745
September 30	411,248	26,085	8,084
December 31	312,205	16,763	(5,123)
1998			
March 31	328,468	51,368	33,744
June 30	348,271	42,194	28,536
September 30	412,908	58,639	38,691
December 31	316,147	13,806	(4,343)

Fourth quarter 1999 and 1998 net loss declined primarily as a result of expenditures to prepare the nuclear units for restart. Fourth quarter 1999 operating income include a favorable adjustment of $21 million net of tax from the deferral of Cook Plant restart expenses net of amortization under the terms of a Michigan jurisdiction settlement agreement approved on December 16, 1999 (see Note 2 for details).

OPERATING STATISTICS

	1999	1998	1997	1996	1995
OPERATING REVENUES (in thousands):					
Retail:					
Residential:					
Without Electric Heating	$ 263,467	$ 265,442	$ 237,475	$ 232,212	$ 239,266
With Electric Heating	114 319	108,950	110,547	111,556	109,504
Total Residential	377,786	374,392	348,022	343,768	348,770
Commercial	290,833	290,149	264,031	253,750	256,319
Industrial	364,607	370,329	332,218	312,777	298,256
Miscellaneous	6,708	6,849	6,465	6,445	6,482
Total Retail	1,039,934	1,041,719	950,736	916,740	909,827
Wholesale (sales for resale)	303,533	321,771	362,392	391,478	357,441
Total Revenues from Energy Sales	1,343,467	1,363,490	1,313,128	1,308,218	1,267,268
Provision for Refunds of Revenues Collected in Prior Years	(1,143)	-	-	-	-
Total Net of Provision For Refunds	1,342,324	1,363,490	1,313,128	1,308,218	1,267,268
Other	51,795	42,304	26,104	20,275	15,889
Total Operating Revenues	$1,394,119	$1,405,794	$1,339,232	$1,328,493	$1,283,157
SOURCES AND USES OF ENERGY (in millions of kilowatthours):					
Sources:					
Net Generated:					
Fossil Fuel	14,202	13,432	14,193	13,304	12,850
Nuclear Fuel	- *	- *	10,421	16,396	13,999
Hydroelectric	96	116	133	99	86
Total Net Generated	14,298	13,548	24,747	29,799	26,935
Purchased and AEP Power Pool	13,336	13,621	9,557	7,581	5,871
Total Sources	27,634	27,169	34,304	37,380	32,806
Less: Losses, Company Use, Etc.	1,714	1,884	1,850	1,795	1,700
Net Sources	25,920	25,285	32,454	35,585	31,106
Uses:					
Retail Sales:					
Residential:					
Without Electric Heating	3,634	3,518	3,307	3,329	3,390
With Electric Heating	1,718	1,616	1,768	1,811	1,768
Total Residential	5,352	5,134	5,075	5,140	5,158
Commercial	4,668	4,540	4,349	4,328	4,300
Industrial	8,236	7,755	7,541	7,295	6,582
Miscellaneous	84	86	82	82	82
Total Retail	18,340	17,515	17,047	16,845	16,122
Wholesale Sales (sales for resale)	7,580	7,770	15,407	18,740	14,984
Total Uses	25,920	25,285	32,454	35,585	31,106

* During 1999 and 1998 the Company's nuclear plant was shutdown for an extended outage which began in September 1997 to address certain safety concerns. See Note 2.

OPERATING STATISTICS (Concluded)

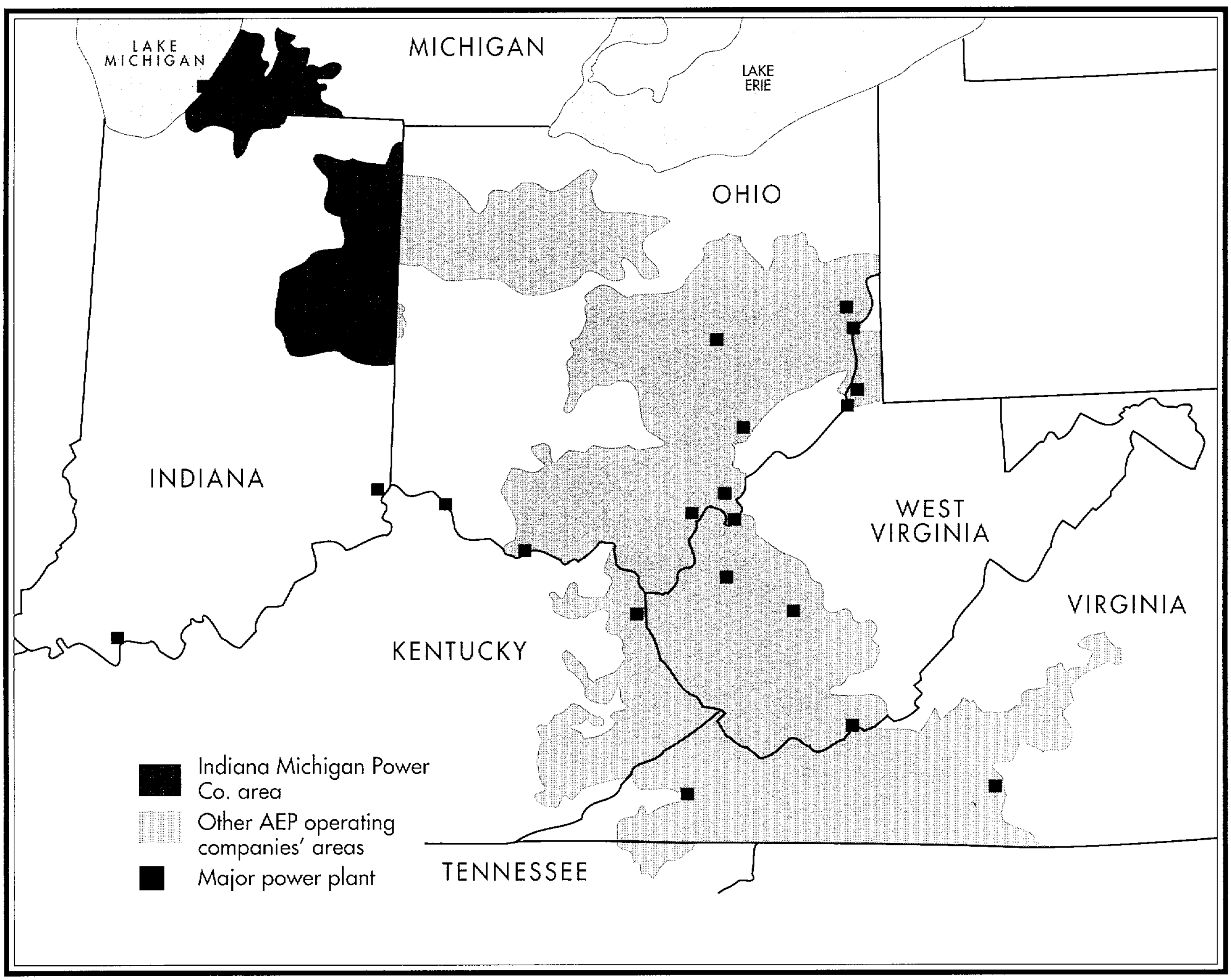
	1999	1998	1997	1996	1995
AVERAGE COST OF FUEL CONSUMED (in cents):					
Per Million Btu:	123	130	89	74	78
Per Kilowatthour Generated:	1.21	1.21	.93	.80	.83
RESIDENTIAL SERVICE - AVERAGES:					
Annual Kwh Use per Customer:					
With Electric Heating	16,839	15,922	17,583	18,206	18,044
Total	10,914	10,566	10,560	10,791	10,943
Annual Electric Bill:					
With Electric Heating	$1,120.78	$1,073.77	$1,099.34	$1,121.41	$1,117.55
Total	$770.49	$770.50	$724.16	$721.76	$739.99
Price per Kwh (in cents):					
With Electric Heating	6.66	6.74	6.25	6.16	6.19
Total	7.06	7.29	6.86	6.69	6.76
NUMBER OF CUSTOMERS:					
Year-End:					
Retail:					
Residential:					
Without Electric Heating	389,905	386,253	383,314	378,757	375,929
With Electric Heating	102,132	102,078	101,492	100,372	99,105
Total Residential	492,037	488,331	484,806	479,129	475,034
Commercial	59,759	58,720	57,311	55,869	55,077
Industrial	5,413	5,437	5,484	5,345	5,316
Miscellaneous	1,969	1,956	1,855	1,820	1,797
Total Retail	559,178	554,444	549,456	542,163	537,224
Wholesale (sales for resale)	148	152	122	85	62
Total Electric Customers	559,326	554,596	549,578	542,248	537,286

DIVIDENDS AND PRICE RANGES OF CUMULATIVE PREFERRED STOCK
By Quarters (1999 and 1998)

	1999 - Quarters				1998 - Quarters			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
CUMULATIVE PREFERRED STOCK								
($100 Par Value)								
4-1/8% Series								
Dividends Paid Per Share	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125	$1.03125
Market Price - $ Per Share								
(CSE) - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
4.56% Series								
Dividends Paid Per Share	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14	$1.14
Market Price - $ Per Share								
(OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	64	64	64-1/4	63-5/8	58-1/2	66	67-5/8	68
- Low	64	64	63-1/2	60-1/8	58-1/4	58-1/2	66	64
4.12% Series								
Dividends Paid Per Share	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03	$1.03
Market Price - $ Per Share								
(OTC)								
Ask - High	-	-	-	-	-	-	-	-
- Low	-	-	-	-	-	-	-	-
Bid - High	70-1/8	70-3/8	70-1/8	68	59-3/8	63-7/8	64-5/8	67-3/8
- Low	67-3/8	70-1/8	67-1/2	67-1/2	58-1/4	59-3/8	63-7/8	64-5/8
5.90% Series								
Dividends Paid Per Share	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475	$1.475
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-1/4% Series								
Dividends Paid Per Share	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625	$1.5625
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6.30% Series								
Dividends Paid Per Share	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575	$1.575
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-
6-7/8% Series								
Dividends Paid Per Share	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875	$1.71875
Market Price - $ Per Share								
(OTC)								
Ask (high/low)	-	-	-	-	-	-	-	-
Bid (high/low)	-	-	-	-	-	-	-	-

CSE - Chicago Stock Exchange
OTC - Over-the-Counter
Note - The above bid and asked quotations represent prices between dealers and do not represent actual transactions.
Market quotations provided by National Quotation Bureau, Inc.
Dash indicated quotation not available.

Indiana Michigan Power Service Area and the American Electric Power System



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ATTACHMENT 2 TO C0500-12

INDIANA MICHIGAN POWER COMPANY
PROJECTED CASH FLOW FOR THE YEAR 2000

Indiana Michigan Power Co.
2000 Forecasted Internal Cash Flow
$ Millions

	Projected 2000
Net income After Taxes	(27.3)
Less: Dividends	105.1
	(132.4)
Adjustments:	
Depreciation and Amortization	154.6
Amortization of Deferred Operating Costs	81.2
Deferred Federal Income Taxes and Investment Tax Credits	(43.4)
AFUDC	(6.1)
Changes in Working Capital	173.1
Other	(4.2)
Total Adjustments	355.2
Internal Cash Flow	222.8
Average Quarterly Cash Flow	55.7
Average Cash Balances and Short-Term Investments	2.9
Total	58.6