Appendix A to the
Proxy Statement

American Electric Power

2001 Annual Report

**Audited Financial Statements and
Management's Discussion and Analysis**

AMERICAN
ELECTRIC
POWER

AMERICAN ELECTRIC POWER
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CONTENTS

Common Stock and Dividend Information

The quarterly high and low sales prices for AEP common stock and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Dividend
March 2001	$48.10	$39.25	$0.60
June 2001	51.20	45.10	0.60
September 2001	48.90	41.50	0.60
December 2001	46.95	39.70	0.60
March 2000	34.94	25.94	0.60
June 2000	38.50	29.44	0.60
September 2000	40.00	29.94	0.60
December 2000	48.94	36.19	0.60

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2001, AEP had approximately 150,000 shareholders of record.

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
2004 True-up Proceeding	A filing to be made after January 10, 2004 under the Texas Legislation to finalize the amount of stranded costs and the recovery of such costs.
AEGCo	AEP Generating Company, an electric utility subsidiary of AEP.
AEP	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned subsidiaries consolidated.
AEP Credit, Inc.	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated and unaffiliated domestic electric utility companies.
AEPR	AEP Resources, Inc.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP Power Pool	AEP System Power Pool. Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale system sales of the member companies.
AFUDC	Allowance for funds used during construction, a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant.
Alliance RTO	Alliance Regional Transmission Organization, an ISO formed by AEP and four unaffiliated utilities.
Amos Plant	John E. Amos Plant, a 2,900 MW generation station jointly owned and operated by APCo and OPCo.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Arkansas Commission	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., an unaffiliated corporation.
CLECO	Central Louisiana Electric Company, Inc., an unaffiliated corporation.
COLI	Corporate owned life insurance program.
Cook Plant	The Donald C. Cook Nuclear Plant, a two-unit, 2,110 MW nuclear plant owned by I&M.
CPL	Central Power and Light Company, an AEP electric utility subsidiary.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP.
CSW Energy.	CSW Energy, Inc., an AEP subsidiary which invests in energy projects and builds power plants.
CSW International	CSW International, Inc., an AEP subsidiary which invests in energy projects and entities outside the United States.
D.C. Circuit Court	The United States Court of Appeals for the District of Columbia Circuit.
DHMV	Dolet Hills Mining Venture.
DOE	United States Department of Energy.
ECOM	Excess Cost Over Market.
ENEC	Expanded Net Energy Costs.
EITF	The Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	The Electric Reliability Council of Texas.
EWGs	Exempt Wholesale Generators.
FASB	Financial Accounting Standards Board
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FMB	First Mortgage Bond.
FUCOs	Foreign Utility Companies.
GAAP	Generally Accepted Accounting Principles.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IPC	Installment Purchase Contract.

IRS .... Internal Revenue Service.
IURC .... Indiana Utility Regulatory Commission.
ISO .... Independent system operator.
Joint Stipulation .... Joint Stipulation and Agreement for Settlement of APCo's WV rate proceeding.
KPCo .... Kentucky Power Company, an AEP electric utility subsidiary.
KPSC .... Kentucky Public Service Commission.
KWH .... Kilowatthour.
LIG .... Louisiana Intrastate Gas.
Michigan Legislation .... The Customer Choice and Electricity Reliability Act, a Michigan law which provides for customer choice of electricity supplier.
Midwest ISO .... An independent operator of transmission assets in the Midwest.
MLR .... Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
Money Pool .... AEP System's Money Pool.
MPSC .... Michigan Public Service Commission.
MTN .... Medium Term Notes.
MW .... Megawatt.
MWH .... Megawatthour.
NEIL .... Nuclear Electric Insurance Limited.
NOx .... Nitrogen oxide.
NOx Rule .... A final rules issued by Federal EPA which requires NOx reductions in 22 eastern states including 7 of the states in which AEP operates.
NP .... Notes Payable.
NRC .... Nuclear Regulatory Commission.
Ohio Act .... The Ohio Electric Restructuring Act of 1999.
Ohio EPA .... Ohio Environmental Protection Agency.
OPCo .... Ohio Power Company, an AEP electric utility subsidiary.
OVEC .... Ohio Valley Electric Corporation, an electric utility company in which AEP and CSPCo own a 44.2% equity interest.
PCBs .... Polychlorinated Biphenyls.
PJM .... Pennsylvania – New Jersey – Maryland regional transmission organization.
PRP .... Potentially Responsible Party.
PSO .... Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO .... The Public Utilities Commission of Ohio.
PUCT .... The Public Utility Commission of Texas.
PUHCA .... Public Utility Holding Company Act of 1935, as amended.
PURPA .... The Public Utility Regulatory Policies Act of 1978.
RCRA .... Resource Conservation and Recovery Act of 1976, as amended.
Rockport Plant .... A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana owned by AEGCo and I&M.
RTO .... Regional Transmission Organization.
SEC .... Securities and Exchange Commission.
SFAS .... Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71 .... Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation.
SFAS 101 .... Statement of Financial Accounting Standards No. 101, Accounting for the Discontinuance of Application of Statement 71.
SFAS 121 .... Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of.
SFAS 131 .... Statement of Financial Accounting Standards No. 131, Disclosure about Segments of an Enterprise and Related Information.
SFAS 133 .... Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.

SFAS 141 .... Statement of Financial Accounting Standards No. 141, Business Combinations.

SNF .... Spent Nuclear Fuel.

SPP... Southwest Power Pool.

STP... South Texas Project Nuclear Generating Plant, owned 25.2% by Central Power and Light Company an AEP electric utility subsidiary .

STPNOC.................................. STP Nuclear Operating Company, a non-profit Texas corporation which operates STP on behalf of its joint owners including CPL.

Superfund .... The Comprehensive Environmental, Response, Compensation and Liability Act.

SWEPCo .... Southwestern Electric Power Company, an AEP electric utility subsidiary.

Texas Appeals Court .... The Third District of Texas Court of Appeals.

Texas Legislation...................... Legislation enacted in 1999 to restructure the electric utility industry in Texas.

Travis District Court .... State District Court of Travis County, Texas.

TVA .... Tennessee Valley Authority.

U.K... The United Kingdom.

UN .... Unsecured Note.

VaR... Value at Risk, a method to quantify risk exposure.

Virginia SCC .... Virginia State Corporation Commission.

WV.. West Virginia.

WVPSC .... Public Service Commission of West Virginia.

WPCo .... Wheeling Power Company, an AEP electric distribution subsidiary.

WTU .... West Texas Utilities Company, an AEP electric utility subsidiary.

Yorkshire .... Yorkshire Electricity Group plc, a U.K. regional electricity company owned jointly by AEP and New Century Energies.

Zimmer Plant .... William H. Zimmer Generating Station, a 1,300 MW coal-fired unit owned 25.4% by Columbus Southern Power Company, an AEP subsidiary.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Selected Consolidated Financial Data

Year Ended December 31,	2001	2000	1999	1998	1997
INCOME STATEMENTS DATA (in millions):					
Total Revenues	$61,257	$36,706	$24,745	$18,420	$11,427
Operating Income	2,395	2,004	2,304	2,258	2,180
Income Before Extraordinary Items And Cumulative Effect	1,003	302	986	975	949
Extraordinary Gain (Loss)	(50)	(35)	(14)	-	(285)
Cumulative Effect of Accounting Change	18	-	-	-	-
Net Income	971	267	972	975	664

December 31,	2001	2000	1999	1998	1997
BALANCE SHEETS DATA (in millions):					
Property, Plant and Equipment	$40,709	$38,088	$36,938	$35,655	$33,496
Accumulated Depreciation And Amortization	16,166	15,695	15,073	14,136	13,229
Net Property, Plant and Equipment	$24,543	$22,393	$21,865	$21,519	$20,267
Total Assets	$47,281	$53,350	$35,693	$33,418	$30,092
Common Shareholders' Equity	8,229	8,054	8,673	8,452	8,220
Cumulative Preferred Stocks Of Subsidiaries*	156	161	182	350	377
Trust Preferred Securities	321	334	335	335	335
Long-term Debt*	12,053	10,754	11,524	11,113	9,354
Obligations Under Capital Leases*	451	614	610	539	549

Year Ended December 31,	2001	2000	1999	1998	1997
COMMON STOCK DATA:					
Earnings per Common Share:					
Before Extraordinary Item and Cumulative Effect	$ 3.11	$ 0.94	$ 3.07	$3.06	$ 2.99
Extraordinary Losses	(0.16)	(0.11)	(0.04)	-	(0.90)
Cumulative Effect of Accounting Change	0.06	-	-	-	-
Earnings Per Share	$ 3.01	$ 0.83	$ 3.03	$3.06	$ 2.09
Average Number of Shares Outstanding (in millions)	322	322	321	318	316
Market Price Range: High	$51.20	$48-15/16	$48-3/16	$53-5/16	$ 52
Low	39.25	25-15/16	30-9/16	42-1/16	39-1/8
Year-end Market Price	43.53	46-1/2	32-1/8	47-1/16	51-5/8
Cash Dividends on Common**	$2.40	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio**	79.7%	289.2%	79.2%	78.4%	114.8%
Book Value per Share	$25.54	$25.01	$26.96	$26.46	$25.91

The consolidated financial statements give retroactive effect to AEP’s merger with CSW, which was accounted for as a pooling of interests.

*Including portion due within one year
**Based on AEP historical dividend rate.

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 both foreign and domestic that could cause actual results to differ materially from forward-looking statements are: electric load and customer growth; abnormal weather conditions; available sources of and prices for coal and gas; availability of generating capacity; risks related to energy trading and construction under contract; the speed and degree to which competition is introduced to our power generation business; the structure and timing of a competitive market for electricity and its impact on prices; the ability to recover net regulatory assets, other stranded costs and implementation costs in connection with deregulation of generation in certain states; the timing of the implementation of AEP's restructuring plan, new legislation and government regulations; the ability to successfully control costs; the success of new business ventures; international developments affecting our foreign investments; the economic climate and growth in our service and trading territories both domestic and foreign; the ability of the Company to comply with and to successfully challenge new environmental regulations and to successfully litigate claims that the Company violated the Clean Air Act; inflationary trends; litigation concerning AEP's merger with CSW; changes in electricity and gas market prices and interest rates; fluctuations in foreign currency exchange rates, and other risks and unforeseen events.

American Electric Power Company, Inc. (AEP) is one of the largest investor owned electric public utility holding companies in the US. We provide generation, transmission and distribution service to over 4.9 million retail customers in eleven states (Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia) through our electric utility operating companies. We market and trade electricity and natural gas in the US and Europe.

We have a significant presence throughout the domestic energy value chain. Our US electric assets include:

- 38,000 megawatts of generating capacity (the largest US generation portfolio with a significant cost advantage in the Midwest and Southwest markets);
- 38,000 miles of transmission lines and
- 186,000 miles of distribution lines

Our natural gas assets include:

- 128 Bcf of gas storage facilities
- 6,400 miles of gas pipelines in Louisiana and Texas which provide a basis for market knowledge.

With our coal and transportation assets we:

- control over 7,000 railcars
- control over 1,800 barges and 37 tug boats
- operate two coal handling terminals with 20 million tons of capacity.
- produce over 7 million tons of coal annually in the US.

AEP is one of the largest traders of electricity and natural gas in the US:

- over 576 million MWH of electricity trades in 2001
- over 3,800 billion cubic feet (Bcf) of gas trades in 2001

In addition we:

- consume 80 million tons of coal annually
- consume 310 Bcf of natural gas annually

AEP's focus is in the US but we also have smaller footprints in other parts of the world:

- a growing energy trading operation in Europe based in the UK.
- 4,000 megawatts of generating capacity in the United Kingdom which represents 16% of the UK's total generation capacity.

Other foreign investments include distribution operations in the U.K., Australia, and Brazil. We have additional generating facilities in China and Mexico. We also offer engineering and construction services worldwide.

Business Strategy

Our strategy is a balanced business model of regulated and unregulated businesses backed by assets, supported by enterprise-wide risk management and a strong balance sheet. We have been focused on the wholesale side of the business since it provides the greater growth opportunities. But, this is complemented by a robust regulated business that has a predictable earnings stream and cash flows. Strong risk management and a disciplined analysis of markets protected us from the California energy crisis and Enron's bankruptcy filing.

Our balanced business model is one where AEP integrates its assets, marketing, trading and market analysis and resources to create a superior knowledge about the commodity markets which keeps us a step ahead of our competition. Our power, gas, coal, and barging assets and operations provide us with market knowledge and customer connectivity giving us the ability to make informed marketing and trading decision and to customize our products and services.

AEP provides investors with a balanced portfolio since it has:

- a growing unregulated wholesale energy marketing and trading business
- predictable cash flow and earnings streams from the regulated electricity business, and
- a high dividend yield relative to today's low-interest rate environment.

We are currently in the process of restructuring our assets and operations to separate the regulated operations from the non-regulated operations.

We filed with the SEC for approval to form two separate legal holding company subsidiaries of AEP Co. Inc., the parent company. Approval is needed from the SEC under the PUHCA and the FERC to make these organizational changes. Certain state regulatory commissions have intervened in the FERC proceedings. We have reached a settlement with those state commissions and are awaiting the FERC's approval before the SEC will make a final ruling on our filing.

We are implementing a corporate separation restructuring plan to support our objective of unlocking shareholder value for our domestic businesses. Our plan provides for:

- transparency and clarity to investors,
- a simpler structure to conduct business, and to anticipate and monitor performance,
- compliance with states' restructuring laws promoting customer choice, and
- more efficient financing.

The new corporate structure will consist of a regulated holding company and an unregulated holding company. The regulated holding company's investments will be in integrated utilities and Ohio and Texas wires. The unregulated holding company's investments will be in Ohio and Texas generation, independent power producers, gas pipe line and storage, UK generation, barging, coal mining and marketing and trading.

The risks in our business are:

- Margin erosion on electric trading as markets mature,
- Diminished opportunities for significant gains as volatility declines,
- Retail price reductions mandated with the implementation of customer choice in Texas and Ohio,
- Movement towards re-regulation in California through market caps and other challenges to the continuation of deregulation of the retail electricity supply business in the U.S.,
- The continued negative impact of a slowly recovering economy.

Our business plan considers these risks and we believe that we can deliver earnings growth of 6-8% annually across the energy value chain through the disciplined integration of strategic assets and intellectual capital to generate these returns for our shareholders.

Our strategies to achieve our business plan are:

- Unregulated
    - Disciplined approach to asset acquisition and disposition
    - Value-driven asset optimization through the linkage of superior commercial, analytical and technical skills
    - Broad participation across all energy markets with a disciplined and opportunistic allocation of risk capital
    - Continued investment in both technology and process improvement to enhance our competitive advantage
    - Continued expansion of intellectual capital through ongoing recruiting, performance-linked compensation and the development of a structure that promotes sound decision-making and innovation at all levels.

- Regulated
    - Maintain moderate but steady earnings growth
    - Maximize value of transmission assets and protect revenue stream through RTO/Alliance membership
    - Continue process improvement to maintain distribution service quality while enhancing financial performance
    - Optimize generation assets through enhanced availability of off-system sale
    - Manage regulatory process to maximize retention of earnings improvement

Our significant accomplishments in 2001 were :

- Adding the following assets to integrate with and support our trading and marketing competitive advantage:
    - 4,200 miles of gas pipeline, 118 Bcf gas storage and related gas marketing contracts
    - 1,200 hopper barges and 30 tugboats
    - 4,000 megawatts of coal-fired generation in England
    - 160 megawatts of wind generation in Texas
    - coal mining properties, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Ohio, Pennsylvania and West Virginia
- Entering into new markets through the acquisition of existing contracts and hiring key staff including 57 employees from Enron's London based international coal trading group in December 2001 and Enron's Nordic energy trading group in January 2002. We now trade power and gas in the UK, France, Germany, and the Netherlands and coal throughout the world
- Adding other energy-related commodities to our power and gas portfolio i.e. coal, SO2 allowances, natural gas liquids (NGLs) and oil
- Disposing of the following assets that did not fit our strategy:
    - 120 MWs of generation in Mexico,
    - Above market coal mines in Ohio and West Virginia,
    - A 50 % investment in Yorkshire, a U.K. electric supply and distribution company,
    - An investment in a Chilean electric company
    - Datapult, an energy information data and analysis tool.

In addition we sold 500 MWs of generating capacity in Texas under a FERC order that approved our merger with CSW.

Our divesture of non-strategic assets is somewhat limited by the pooling of interest accounting requirements applied to the merger of CSW and AEP in June 2000. We are presently evaluating certain telecommunications and foreign investments for possible disposal and have not yet decided whether to dispose of such investments. Disposal of investments determined to be non-strategic will be considered in accordance with the pooling of interests restrictions which end in June 2002. We are committed to continually evaluate the need to reallocate resources to areas with greater potential, to match investments with our strategy and to pare investments that do not produce sufficient return and shareholder value. Any investment dispositions could affect future results of operations.

Outlook for 2002

Growth in 2002 will be driven in part by our continued strategic development of wholesale products and geographies, as demonstrated in recent months by our move into global coal markets and Nordic energy. A full year of operation of assets acquired in 2001 – Houston Pipe Line, Quaker Coal, the MEMCO barge line and two power plants in the United Kingdom – will also contribute to growth in 2002 earnings.

Although we expect that the future outlook for results of operations is excellent there are contingencies and challenges. We discuss these matters in detail in the Notes to Consolidated Financial Statements and below in this Management Discussion and Analysis. We intend to work diligently to resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our shareholders.

As discussed above we expect to continue evaluating certain investments for possible disposal due to either their non-strategic nature or limited future earnings potential for AEP. Any dispositions could result in gains or losses being recorded in our income statement.

Industry Restructuring

In 2000 California's deregulated electricity market suffered problems including high energy prices mainly due to short energy supplies and financial difficulties for retail distribution companies. This energy crisis has highlighted the importance of risk management and has contributed to certain state regulatory and legislative actions which have delayed the start of customer choice and the transition to competitive, market based pricing for retail electricity supply in some of the states in which AEP operates. Seven of the eleven state retail jurisdictions in which the AEP domestic electric utility companies operate have enacted restructuring legislation. In general, the legislation provides for a transition from cost-based regulation of bundled electric service to customer choice and market pricing for the supply of electricity. As legislative and regulatory proceedings evolved, six AEP electric operating companies (APCo, CPL, CSPCo, OPCo, SWEPCo and WTU) doing business in five of the seven states that have passed restructuring legislation have discontinued the application of SFAS 71 regulatory accounting for the generation business. The seven states in various stages of restructuring to transition power generation and supply to market based pricing are Arkansas, Michigan, Ohio, Oklahoma, Texas, Virginia, and West Virginia. AEP has not discontinued its regulatory accounting for its subsidiaries doing business in Michigan and Oklahoma pending the effective implementation of the legislation. Restructuring legislation, the status of the transition plans and the status of the electric utility companies' accounting to comply with the changes in each of AEP's seven state regulatory jurisdictions affected by restructuring legislation is presented in the Note 7 of the Notes to Financial Statements.

RTO Formation

FERC Order No. 2000 and many of the settlement agreements with the FERC and state regulatory commissions to approve the AEP-CSW Merger have provisions for the transfer of functional control of our transmission system to an RTO. Certain AEP subsidiaries are participating in the formation of the Alliance RTO. Other subsidiaries are a member of ERCOT or SPP.

In 2001 the Alliance companies and MISO entered into a settlement addressing transmission pricing and other "seam" issues between the two RTOs. The FERC subsequently expressed its opinion that four large RTO regions serving the continental US would best support competition and reliability of electric service. Certain state regulatory commissions have taken exception to the FERC's RTO actions. Louisiana's commission ordered utilities it regulates, including SWEPCo, to show the advantage of large RTOs to their customers.

On December 19, 2001 the FERC approved the proposal of the Midwest ISO for a regional transmission organization and told the Alliance companies, which had submitted a separate RTO proposal, to explore joining the Midwest ISO organization. The FERC's order is intended to facilitate the establishment of a single RTO in the Midwest and to support the establishment of viable, for-profit transmission companies under an RTO umbrella and concluded that the RTO proposed by Alliance companies lacks sufficient scope to exist as a stand-alone RTO and thus directed the Alliance companies to explore how their business plan can be accommodated within the Midwest ISO.

Management is unable to predict the outcome of these transmission regulatory actions and proceedings or their impact on the timing and operation of RTOs, AEP's transmission operations or future results of operations and cash flows.

RESULTS OF OPERATIONS

In 2001 AEP's principal operating business segments and their major activities were:

- Wholesale:
  - Generation of electricity for sale to retail and wholesale customers
  - Gas pipeline and storage services
  - Marketing and trading of electricity, gas and coal
  - Coal mining, bulk commodity barging operations and other energy supply related business.
- Energy Delivery
  - Domestic electricity transmission,
  - Domestic electricity distribution
- Other Investments
  - Foreign electric distribution and supply investments,
  - Telecommunication services.

Net Income

Net income increased to $971 million or $3.01 per share from $267 million or $0.83 per share. The increase of $704 million or $2.18 per share was due to the growth of AEP's wholesale marketing and trading business, increased revenues and the controlling of our operating and maintenance costs in the energy delivery business, and declining capital costs. Also contributing to the earnings improvement in 2001 was the effect of 2000 charges for a disallowance of COLI-related tax deductions, expenses of the merger with CSW, write-offs related to non-regulated investments and restart costs of the Cook Nuclear Plant. The favorable effect on comparative net income of these 2000 charges was offset in part by current year losses from Enron's bankruptcy and extraordinary losses for the effects of deregulation and a loss on reacquired debt.

The decline in net income to $267 million or $0.83 per share in 2000 from $972 million or $3.03 per share in 1999 was primarily due to the 2000 charges described above and an extraordinary losses from the discontinuance of regulatory accounting for generation in certain states.

A strong performance in the first nine months of 2001 was partially offset by unfavorable operating conditions in the fourth quarter. Extremely mild November and December weather combined with weak economic conditions in the fourth quarter, reduced retail energy sales and wholesale margins. Heating degree days in the fourth quarter were down 33% from the same period in 2000. Although the fourth quarter was disappointing, 2001 net income before extraordinary items and cumulative effect of accounting change reached the $1 billion mark.

Our wholesale business continues to perform well despite a slowing economy that reduced both wholesale energy margins and energy use by industrial customers. Our wholesale business, which includes generation, retail and wholesale sales of power and natural gas and trading of power and natural gas and natural gas pipeline and storage services, contributed to the earnings increase by successfully returning the Cook Plant to service in 2000 and by growing AEP's wholesale business.

Our energy delivery business, which consists of domestic electricity transmission and distribution services, contributed to the increase in earnings by controlling operating and maintenance expenses and by increasing revenues.

Capital costs decreased due primarily to interest paid to the IRS in 2000 on a COLI deduction disallowance and declining short-term market interest rate conditions.

Critical Accounting Policies

Revenue Recognition – *Traditional Electricity Supply and Delivery Activities* - As the owner of cost-based rate-regulated electric public utility companies, AEP Co., Inc.'s consolidated financial statements recognize revenues on an accrual basis for traditional electricity supply sales and for electricity transmission and distribution delivery services. These revenues are recognized in our income statement when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when incurred. As a result of our cost based rate regulated operations, our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching in the same accounting period regulated expenses with their recovery through regulated revenues.

When regulatory assets are probable of recovery through regulated rates, we record them as assets on the balance sheet. We test for probability of recovery whenever new events occur, for example a regulatory commission order or passage of new legislation. If we determine that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against net income. A write off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

We discontinued application of SFAS 71 for the generation portion of our business in Ohio for OPCo and CSPCo in September 2000, in Virginia and West Virginia for APCo in June 2000, in Texas for CPL, WTU, and SWEPCo in September 1999 and in Arkansas for SWEPCo in September 1999 in recognition of the passage of legislation to transition to customer choice and market pricing for the supply of electricity. We recorded extraordinary losses when we discontinued the application of SFAS 71. See Note 2, "Extraordinary Items and Cumulative Effect" for additional information.

Wholesale Energy Marketing and Trading Activities - We engage in non-regulated wholesale electricity and natural gas marketing and trading transactions (trading activities). Trading activities involve the purchase and sale of energy under forward contracts at fixed and variable prices and buying and selling financial energy contracts which includes exchange futures and options and over-the-counter options and swaps. Although trading contracts are generally short-term, there are also long-term trading contracts. We recognize revenues from trading activities generally based on changes in the fair value of energy trading contracts.

Recording the net change in the fair value of trading contracts as revenues prior to settlement is commonly referred to as mark-to-market (MTM) accounting. It represents the change in the unrealized gain or loss throughout the contract's term. When the contract actually settles, that is, the energy is actually delivered in a sale or received in a purchase or the parties agree to forego delivery and receipt and net settle in cash, the unrealized gain or loss is reversed out of revenues and the actual realized cash gain or loss is recognized in revenues for a sale or in purchased energy expense for a purchase. Therefore, over the term of the trading contracts an unrealized gain or loss is recognized as the contract's market value changes. When the contract settles the total gain or loss is realized in cash but only the difference between the accumulated unrealized net gains or losses recorded in prior months and the cash proceeds is recognized. Unrealized mark-to-market gains and losses are included in the Balance Sheet as energy trading and derivative contract assets or liabilities as appropriate.

The majority of our trading activities represent physical forward electricity and gas contracts that are typically settled by entering into offsetting contracts. An example of our trading activities is when, in January, we enter into a forward sales contract to deliver electricity or gas in July. At the end of each month until the contract settles in July, we would record any difference between the contract price and the market price as an unrealized gain or loss in revenues. In July when the contract settles, we would realize the gain or loss in cash and reverse to revenues the previously recorded unrealized gain or loss. Prior to settlement, the change in the fair value of physical forward sale and purchase contracts is included in revenues on a net basis. Upon settlement of a forward trading contract, the amount realized is included in revenues for a sales contract and realized costs are included in purchased energy expense for a purchase contract with the prior change in unrealized fair value reversed in revenues.

Continuing with the above example, assume that later in January or sometime in February through July we enter into an offsetting forward contract to buy electricity or gas in July. If we do nothing else with these contracts until settlement in July and if the commodity type, volumes, delivery point, schedule and other key terms match then the difference between the sale price and the purchase price represents a fixed value to be realized when the contracts settle in July. If the purchase contract is perfectly matched with the sales contract, we have effectively fixed the profit or loss; specifically it is the difference between the contracted settlement price of the two contracts. Mark-to-market accounting for these contracts will have no further impact on operating results but has an offsetting and equal effect on trading contract assets and liabilities. Of course we could also do similar transactions but enter into a purchase contract prior to entering into a sales contract. If the sale and purchase contracts do not match exactly as to commodity type, volumes, delivery point, schedule and other key terms, then there could be continuing mark-to-market effects on revenues from recording additional changes in fair values using mark-to-market accounting.

Trading of electricity and gas options, futures and swaps, represents financial transactions with unrealized gains and losses from changes in fair values reported net in revenues until the contracts settle. When these contracts settle, we record the net proceeds in revenues and reverse to revenues the prior unrealized gain or loss.

The fair value of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based mainly on Company-developed valuation models. These models estimate future energy prices based on existing market and broker quotes and supply and demand market data and assumptions. The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. There are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. We have independent controls to evaluate the reasonableness of our valuation models. However, energy markets, especially electricity markets, are imperfect and volatile and unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and when contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices do not correlate with the Company-developed price models.

We also mark to market derivatives that are not trading contracts in accordance with generally accepted accounting principles. Derivatives are contracts whose value is derived from the market value of an underlying commodity.

Our revenues of $61 billion for 2001 included $257 million of unrealized net gains from marking to market open trading and derivative contracts. AEP's net revenues, (revenues less fuel and energy purchases) excluding mark-to-market revenues totaled $8.3 billion and were realized during 2001. Unrealized net mark-to-market revenues are only 3% of total net revenues. A significant portion of the net unrealized revenues from marking to market trading contracts and derivatives included in our balance sheet at December 31, 2001 as energy trading and derivative contract assets and liabilities, will be realized in 2002.

We defer as regulatory assets or liabilities the effect on net income of marking to market open electricity trading contracts in our regulated jurisdictions since these transactions are included in cost of service on a settlement basis for ratemaking purposes. Changes in mark-to-market valuations impact net income in our non-regulated business.

Volatility in energy commodities markets affects the fair values of all of our open trading and derivative contracts exposing AEP to market risk causing our results of operations to be more volatile. See "Market Risks" section below for a discussion of the policies and procedures AEP uses to manage its exposure to market and other risks from trading activities.

Revenues

Our revenues have increased significantly from the marketing and trading of electricity and natural gas. The level of electricity trading transactions tends to fluctuate due to the highly competitive nature of the short-term (spot) energy market and other factors, such as affiliated and unaffiliated generating plant availability, weather conditions and the economy. The FERC's introduction of a greater degree of competition into the wholesale energy market, has had a major effect on the volume of wholesale power marketing and trading especially in the short-term market.

AEP's total revenues increased 66.9% in 2001 and 48.3% in 2000. The following table shows the components of revenues in millions.

	For The Year Ended December 31		
	2001	2000	1999
	(in millions)		
WHOLESALE BUSINESS:			
Residential	$ 3,553	$ 3,511	$ 3,290
Commercial	2,328	2,249	2,083
Industrial	2,388	2,444	2,515
Other Retail Customers	419	414	394
Electricity Marketing and Trading	35,339	18,858	11,417
Gas Marketing and Trading	14,369	6,127	2,290
Unrealized MTM Income:			
Electric	210	38	2
Gas	47	132	21
Other	632	838	599
Less Transmission and Distribution Revenues Assigned to Energy Delivery*	(3,356)	(3,174)	(3,068)
TOTAL WHOLESALE BUSINESS	55,929	31,437	19,543
ENERGY DELIVERY BUSINESS:			
Transmission	1,029	1,009	960
Distribution	2,327	2,165	2,108
TOTAL ENERGY DELIVERY	3,356	3,174	3,068
OTHER INVESTMENTS:			
SEEBOARD	1,451	1,596	1,705
CITIPOWER	350	338	318
Other	171	161	111
TOTAL OTHER INVESTMENTS	1,972	2,095	2,134
TOTAL REVENUES	$61,257	$36,706	$24,745

*Certain revenues in Wholesale business include energy delivery revenues due primarily to bundled tariffs that are assignable to the Energy Delivery business.

The $25 billion increase in 2001 revenues was due to substantial increases in electric and gas trading volumes. The increase in sales of purchased power and purchased gas during the past two years reflect AEP's intention to be a leading national wholesale energy merchant. Wholesale natural gas trading volume for 2001 was 3,874 Bcf, a 178% increase from 2000 volume of 1,391 Bcf. Electric trading volume increased 48% to 576 million MWH. We have invested in resources required to optimize our assets and emerge as a leader in the industry. The maturing of the Intercontinental Exchange, the development of proprietary tools, and the increased staffing of energy traders have faciliated increased power and gas sales. Our June 2001 purchase of Houston Pipe Line enhanced our gas trading and marketing operation. Although we will trade and market only when we believe profitable opportunites exist, we expect the increased level of activity to continue.

While wholesale marketing and trading volumes rose, kilowatthour sales to industrial customers decreased by 5% in 2001. This decrease was due to the economic recession. In the fourth quarter, sales to residential, commercial and wholesale customers declined 9%. The recession reduced demand and wholesale prices especially in the fourth quarter.

While margins available from selling power that the company generates generally are higher than from selling purchased power, such sales are limited by the amount of generating assets owned. Furthermore, the profit available from simply selling excess generation is reduced by the inherent market transparency of such sales. The coordinated sales of excess generation in conjunction with trading and marketing activity optimizes assets, mitigates risk, and increases overall profit.

The $12 billion increase in 2000 revenues was primarily due to a 27% increase in wholesale electricity trading volume and increased retail fuel revenues as a result of higher gas prices used to generate electricity. The reduction in industrial revenues in 2000 is attributable to the expiration of a long-term contract on December 31, 1999. The significant increase in 2000 electricity trading volume, which accounted for a 66% increase in electricity trading revenues, resulted from:

- efforts to grow AEP's energy marketing and trading operations,
- favorable market conditions, and
- the availability of additional generation

Generation availability improved due to the return to service of one of the Cook Plant nuclear units in June 2000 and to improved outage management. The second Cook Plant unit which returned to service in December 2000 did not have a significant impact on 2000 revenues. Gas revenues increased in 2000 due to increased natural gas and gas liquid product prices.

Operating Expenses Increase

Changes in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year			
(Dollars in Millions)	2001		2000	
	Amount	%	Amount	%
Fuel and Purchased Energy	$24,035	83.7	$11,474	66.5
Maintenance and Other Operation	196	5.1	565	17.2
Non-recoverable Merger Costs	(182)	(89.7)	203	N.M.
Depreciation and Amortization	133	10.6	38	3.1
Taxes Other Than Income Taxes	(22)	(3.2)	(19)	(2.7)
Total	$24,160	69.6	$12,261	54.6

Our fuel and purchased energy expense in 2001 increased 84% due to increased trading volume and an increase in nuclear generation cost. The return to service of the Cook Plant's two nuclear generating units in June 2000 and December 2000 accounted for the increase in nuclear generation costs.

Fuel and purchased energy expense increased 67% in 2000 due to increased trading volume and a significant increase in the cost of natural gas used for generation. Natural gas usage for generation declined 5% while the cost of natural gas consumed rose 60%. Net income was not impacted by this significant cost increase due to the operation of fuel recovery rate mechanisms. These fuel recovery rate mechanisms generally provide for the deferral of fuel costs above the amounts included in existing rates or the accrual of revenues for fuel costs not yet recovered. Upon regulatory commission review and approval of the unrecovered fuel costs, the accrued or deferred amounts are billed to customers. With the introduction of customer choice of electricity supplier and a transition to market-based generation rates, the protection offered by fuel recovery mechanisms against changes in fuel costs was eliminated in Ohio effective January 1, 2001 and in the ERCOT area of Texas effective January 1, 2002. As a result, AEP's exposure to the risk of fuel price increases that could adversely affect future results of operations and cash flows is increasing. See Note 1 for applicability of fuel recovery mechanisms by jurisdiction.

Maintenance and other operation expense rose in 2001 mainly as a result of additional traders' incentive compensation and accruals for severance costs related to corporate restructuring.

The increase in maintenance and other operation expense in 2000 was mainly due to increased expenditures to prepare the Cook Plant nuclear units for restart following an extended NRC monitored outage and increased usage and prices of emissions allowances. The increase in Cook Plant restart costs resulted from the effect of deferring restart costs in 1999 and an increase in the restart expenditure level in 2000. Cook Plant began its extended outage in September 1997 when both nuclear generating units were shut down because of questions regarding the operability of certain safety systems. In 1999 a portion of incremental restart expenses were deferred in accordance with IURC and MPSC settlement agreements which resolved all jurisdictional rate-related issues related to the Cook Plant's extended outage. With NRC approval Unit 2 returned to service in June and achieved full power operation on July 5, 2000 and Unit 1 returned to service in December and achieved full power operation on January 3, 2001. The increase in emission allowance usage and prices resulted from the stricter air quality standards of Phase II of the 1990 Clean Air Act Amendments, which became effective on January 1, 2000.

With the consummation of the merger with CSW, certain deferred merger costs were expensed in 2000. The merger costs charged to expense included transaction and transition costs not allocable to and recoverable from ratepayers under regulatory commission approved settlement agreements to share net merger savings. As expected merger costs declined in 2001 after the merger was consummated.

Depreciation and amortization expense increased in 2001 primarily as a result of the commencement of amortization of transition generation regulatory assets in the Ohio, Virginia and West Virginia jurisdictions due to passage of restructuring legislation, the new businesses acquired in 2001 and additional investments in property, plant and equipment.

Interest, Preferred Stock Dividends, Minority Interest

Interest expense deceased 15% in 2001 due to the effect of interest paid the IRS on a COLI deduction disallowance in 2000 and lower average outstanding short-term debt balances and a decrease in average short-term interest rates.

In 2001 we issued a preferred member interest to finance the acquisition of HPL and paid a preferred return of $13 million to the preferred member interest.

In 2000 interest increased by 17% due to additional interest expense from the ruling disallowing COLI tax deductions and AEP's effort to maintain flexibility for corporate separation by issuing short-term debt at flexible rates. The use of fixed interest rate swaps has been employed to mitigate the risk from floating interest rates.

Other Income

Other income increased $166 million in 2001. This increase was primarily caused by the sale in March 2001 of Frontera, a generating plant required to be divested under a FERC approved merger settlement agreement, which produced a pretax $73 million gain and the effect from the December 2000 impairment writedown of $43 million to reflect the pending sale of AEP's Yorkshire investment.

Other income decreased $66 million in 2000 primarily due to a loss in equity earnings from the 2000 write-down of the Yorkshire investment and losses from certain non-regulated subsidiaries accounted for on an equity basis. Other expenses increased in 2000 mainly from a charge for the discontinuance of an electric storage water heater demand side management program of the regulated business.

Income Taxes

Although pre-tax book income increased considerably, income taxes decreased due to the effect of recording in 2000 prior year federal income taxes as a result of the disallowance of COLI interest deductions by the IRS and nondeductible merger related costs in 2000.

Income taxes increased in 2000 over 1999 levels primarily due to the disallowance of the COLI interest deductions and the non-deductible merger related costs discussed above.

Extraordinary Losses and Cumulative Effect

In 2001 we recorded an extraordinary loss of $48 million net of tax to write-off prepaid Ohio excise taxes stranded by Ohio deregulation. The application of regulatory accounting for generation was discontinued in 2000 for the Ohio, Virginia and West Virginia jurisdictions which resulted in the after tax extraordinary loss of $35 million.

New accounting rules that became effective in 2001 regarding accounting for derivatives required us to mark to market certain fuel supply contracts that qualify as financial derivatives. The effect of initially adopting the new rules at July 1, 2001 was a favorable earnings effect of $18 million, net of tax, which is reported as a cumulative effect of accounting change.

FINANCIAL CONDITION

We measure the financial condition of the Company by the strength of its balance sheet, the liquidity provided by its cash flows and earnings.

Balance sheet capitalization ratios and cash flow ratios are principal determinants of the Company's credit quality.

Year-end ratings of the Company's subsidiaries' first mortgage bonds are listed in the following table:

Company	Moody's	S&P	Fitch
APCo	A3	A	A-
CPL	A3	A-	A
CSPCo	A3	A-	A
I&M	Baa1	A-	BBB+
KPCo	Baa1	A-	BBB+
OPCo	A3	A-	A-
PSO	A1	A	A+
SWEPCO	A1	A	A+
WTU	A2	A-	A

The ratings at the end of the year for senior unsecured debt issued by the Company's subsidiaries are listed in the following table:

Company	Moody's	S&P	Fitch
AEP	Baa1	BBB+	BBB+
AEP Resources*	Baa1	BBB+	BBB+
APCo	Baa1	BBB+	BBB+
CPL	Baa1	BBB+	A-
CSPCo	A3	BBB+	A-
I&M	Baa2	BBB+	BBB
KPCo	Baa2	BBB+	BBB
OPCo	A3	BBB+	BBB+
PSO	A2	BBB+	A
SWEPCO	A2	BBB+	A

- The rating is for a series of senior notes issued with a Support Agreement from AEP.

The ratings are presently stable. The parent company's commercial paper program has short-term ratings of A2 and P2 by Moody's and Standard and Poor's, respectively.

AEP's common equity to total capitalization declined to 33% in 2001 from 34% in 2000. Total capitalization includes long-term debt due within one year, minority interests and short-term debt. Preferred stock at 1% remained unchanged. Long-term debt increased from 47% to 50% while short-term debt decreased from 18% to 13% and minority interest in finance subsidiary increased to 3%. In 2001 and 2000, the Company did not issue any shares of common stock to meet the requirements of the Dividend Reinvestment and Direct Stock Purchase Plan and the Employee Savings Plan.

We plan to strengthen the Company's balance sheet in 2002 by issuing common stock and mandatory convertible preferred stock and using the proceeds from asset sales to reduce debt. The issuance of common stock has the potential to dilute future earnings per share but will enhance the equity to capitalization ratio.

Rating agencies have become more focused in their evaluation of credit quality as a result of the Enron bankruptcy. They are focusing especially on the composition of the balance sheet (off-balance sheet leases, debt and special purpose financing structures), the cash liquidity profile and the impact of credit quality downgrades on financing transactions. We have worked closely with the agencies to provide them with all the information they need, but we are unable to predict what actions, if any, they may take regarding the Company's current ratings.

During 2001 cash flow from operations was $2.9 billion, including $971 million from net income and $1.5 billion from depreciation, amortization and deferred taxes. Capital expenditures including acquisitions were $4 billion and dividends on common stock were $773 million. Cash from operations less dividends on common stock financed 52% of capital expenditures.

During 2001, the proceeds of the $1.25 billion global notes issuance and proceeds from the sale of a UK distribution company and two generating plants provided cash to purchase assets, fund construction, retire debt and pay dividends. Major construction expenditures include amounts for a wind generating facility and emission control technology on several coal-fired generating units (see discussion in Note 8). Asset purchases include HPL, coal mines, a barge line, a wind generating facility and two coal-fired generating plants in the UK. These acquisitions accounted for the increase in total debt in 2001. During the third quarter of 2001, permanent financing was completed for the acquisition of HPL by the issuance of a minority interest which provided $735 million net of expenses (See Note 22 for discussion of the terms). HPL's permanent financing increased funds available for other corporate purposes. Long-term financings for the other acquisitions will be announced as arranged. Long-term funding arrangements for specific assets are often complex and typically not completed until after the acquisition.

Earnings for 2001 resulted in a dividend payout ratio of 80%, a considerable improvement over the 289% payout ratio in 2000. The abnormally high ratio in 2000 was the result of the adverse impact on 2000 earnings from the Cook Plant extended outage and related restart expenditures, merger costs and the write-off related to COLI and non-regulated subsidiaries. We expect continued improvement of the payout ratio as a result of earnings growth in 2002.

Cash from operations and short-term borrowings provide working capital and meet other short-term cash needs. We generally use short-term borrowings to fund property acquisitions and construction until long-term funding mechanisms are arranged. Some acquisitions of existing business entities include the assumption of their outstanding debt and certain liabilities. Sources of long-term funding include issuance of AEP common stock, minority interest or long-term debt and sale-leaseback or leasing arrangements. We operate a money pool and sell accounts receivables to provide liquidity for the domestic electric subsidiaries. Short-term borrowings in the U.S. are supported by two revolving credit agreements. At December 31, 2001, approximately $554 million remained available for short-term borrowings in the US.

Subsidiaries that trade energy commodities in Europe have a separate multicurrency revolving loan and letters of credit agreement allowing them to borrow up to 150 million Euros of which 42 million Euros were available on December 31, 2001. In February 2002 they also originated a temporary second line of 50 million Euros for three months which is expected to be replaced with a 150 million Euro line, providing for a total of 300 million Euros. SEEBOARD, Nanyang and Citipower which operate in the UK, China and Australia, respectively, each have independent financing arrangements which provide for borrowing in the local currency. SEEBOARD has a 320 million pound revolving credit agreement it uses for short-term funding purposes. At December 31, 2001, SEEBOARD had 117 million pounds available.

Our revolving credit agreements include covenants that require us to maintain specified financial ratios and describe non-performance of certain actions as events of default. At December 31, 2001 we complied with the covenants of these agreements. In general, a default in excess of $50 million under one agreement is considered a default under the other agreements. In the case of a default on payments under these agreements, all amounts outstanding would be immediately payable.

The contractual obligations of AEP include amounts reported on the balance sheet and other obligations disclosed in our footnotes. The following table summarizes AEP's contractual cash obligations at December 31, 2001:

	Payments Due by Period (in millions)				
Contractual Cash Obligations	Less Than 1 year	2-3 years	4–5 years	After 5 years	Total
Long-term Debt	$2,300	$2,988	$2,559	$ 4,246	$12,093
Short-term Debt	3,155	-	-	-	3,155
Trust Preferred Securities	-	-	-	321	321
Minority Interest In Finance Subsidiary (a)	-	-	750	-	750
Preferred Stock Subject to Mandatory Redemption	-	24	4	67	95
Capital Lease Obligations	96	144	91	397	728
Unconditional Purchase Obligations (b)	317	1,658	1,299	3,559	6,833
Noncancellable Operating Leases	286	526	488	2,671	3,971
Other Long-term Obligations (c)	31	30	-	-	61
Total Contractual Cash Obligations	$6,185	$5,370	$5,191	$11,261	$28,007

(a) The initial period of the preferred interest is through August 2006. At the end of the initial period, the preferred rate may be reset, the preferred member interests may be re-marketed to new investors, the preferred member interests may be redeemed, in whole or in part including accrued return, or the preferred member interest may be liquidated.
(b) Represents contractual obligations to purchase coal and natural gas as fuel for electric generation along with related transportation of the fuel.
(c) Represents contractual obligations to loan funds to a joint venture accounted for under the equity method.

Special purpose entities have been employed for some of the contractual cash obligations reported in the above table. The lease of Rockport Plant Unit 2 and the Gavin Plant's flue gas desulfurization system (Gavin Scrubbers), the permanent financing of HPL and the sale of accounts receivable use special purpose entities. Neither AEP nor any AEP related parties has an ownership interest in the special purpose entities. AEP does not guarantee the debt of these entities. These special purpose entities are not consolidated in AEP's financial statements in accordance with generally accepted accounting principles. As a result, neither the assets nor the debt of the special purpose entities is included on AEP's balance sheet. The future cash obligations payable to the special purpose entities are included in the above table

In addition to the amounts disclosed in the contractual cash obligations table above, AEP makes commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds, and other commitments. AEP's commitments outstanding at December 31, 2001 under these agreements are summarized in the table below:

	Amount of Commitment Expiration Per Period (in millions)				
Other Commercial Commitments	Less Than 1 year	2-3 years	4–5 years	After 5 years	Total
Standby Letters of Credit	$ 101	$ 53	-	$36	$ 190
Guarantees	815	161	-	15	991
Construction of Generating and Transmission Facilities for Third Parties (a)	168	540	-	-	708
Other Commercial Commitments (b)	6	45	40	24	115
Total Commercial Commitments	$1,090	$799	$40	$75	$2,004

(a) As construction agent for third party owners of power plants and transmission facilities, the Company has committed by contract terms to complete construction by dates specified in the contracts. Should the Company default on these obligations, financial payments could be up to 100% of contract value (amount shown in table) or other remedies required by contract terms.
(b) Represents estimated future payments for power to be generated at facilities under construction.

AEP, through certain subsidiaries, has entered into agreements with an unrelated, unconsolidated special purpose entity (SPE) to develop, construct, finance and lease a power generation facility. The SPE will own the power generation facility and lease it to an AEP consolidated subsidiary after construction is completed. The lease will be accounted for as an operating lease with the payment obligations included in the lease footnote. Payments under the operating lease are expected to commence in the first quarter of 2004. AEP will in turn sublease the facility to an unrelated industrial company which will both use the energy produced by the facility and sell excess energy. Another affiliate of AEP has agreed to purchase the excess energy from the subleasee for resale.

The SPE has an aggregate financing commitment from equity and debt participants (Investors) of $427 million. AEP, in its role as construction agent for the SPE, is responsible for completing construction by December 31, 2003. In the event the project is terminated before completion of construction, AEP has the option to either purchase the project for 100% of project costs or terminate the project and make a payment to the Lessor for 89.9% of project costs.

The term of the operating lease between the SPE and the AEP subsidiary is five years with multiple extension options. If all extension options are exercised the total term of the lease would be 30 years. AEP's lease payments to the SPE are sufficient to provide a return to the Investors. At the end of the first five-year lease term or any extension, AEP may renew the lease at fair market value subject to Investor approval; purchase the facility at its original construction cost; or sell the facility, on behalf of the SPE, to an independent third party. If the project is sold and the proceeds from the sale are insufficient to repay the Investors, AEP may be required to make a payment to the Lessor of up to 85% of the project's cost. AEP has guaranteed a portion of the obligations of its subsidiaries to the SPE during the construction and post-construction periods.

As of December 31, 2001, project costs subject to these agreements totaled $168 million, and total costs for the completed facility are expected to be approximately $450 million. Since the lease is accounted for as an operating lease for financial accounting purposes, neither the facility nor the related obligations are reported on AEP's balance sheets. The lease is a variable rate obligation indexed to three-month LIBOR. Consequently as market interest rates increase, the payments under this operating lease will also increase. Annual payments of approximately $12 million represent future minimum payments under the first five-year lease term calculated using the indexed LIBOR rate of 2.85% at December 31, 2001.

The lease payments and the guarantee of construction commitments are included in the Other Commercial Commitments table above.

OPCo has entered into a purchased power agreement to purchase electricity produced by an unaffiliated entity's three-unit natural gas fired plant that is under construction. The first unit is anticipated to be completed in October 2002 and the agreement will terminate 30 years after the third unit begins operation. Under the terms of the agreement OPCo has the option to run the plant until December 31, 2005 taking 100% of the power generated. For the re-mainder of the 30 year contract term, OPCo will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity. The estimated fixed payments through December 2005 are $55 million and are included in the Other Commercial Commitments table shown above.

Minority Interest in Finance Subsidiary

In August 2001, AEP formed Caddis Partners, LLC (Caddis), a consolidated subsidiary, and sold a non-controlling preferred member interest in Caddis to an unconsolidated special purpose entity (Steelhead) for $750 million. Under the provisions of the Caddis formation agreements, the preferred member interest receives quarterly a preferred return equal to an adjusted floating reference rate (4.413% at December 31, 2001). The $750 million received replaced interim funding used to acquire Houston Pipe Line Company in June

2001.

The preferred interest is supported by natural gas pipeline assets and $321.4 million of preferred stock issued by an AEP subsidiary to the AEP affiliate which has the managing member interest in Caddis. Such preferred stock is convertible into common stock of AEP upon the occurrence of certain events. AEP can elect not to have the transaction supported by such preferred stock if the preferred interest were reduced by $225 million. In addition, Caddis has the right to redeem the preferred member interest at any time.

The initial period of the preferred interest is through August 2006. At the end of the initial period, Caddis will either reset the preferred rate, re-market the preferred member interests to new investors, redeem the preferred member interests, in whole or in part including accrued return, or liquidate in accordance with the provisions of applicable agreements.

The credit agreement between Caddis and the AEP subsidiary that acts as its managing member contains covenants that restrict incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. Financial covenants impose minimum financial ratios. At December 31, 2001, we satisfied all of the financial ratio requirements. In general, a default in excess of $50 million under another agreement is considered a default under this agreement.

Steelhead has the right to terminate the transaction and liquidate Caddis upon the occurrence of certain events including a default in the payment of the preferred return. Steelhead's rights include: forcing a liquidation of Caddis and acting as the liquidator, and requiring the conversion of the $321.4 million of AEP subsidiary preferred stock into AEP common stock. If the preferred member interest exercised its rights to liquidate under these conditions, then AEP would evaluate whether to refinance at that time or relinquish the assets that support the preferred member interest. Liquidation of the preferred interest or of Caddis could impact AEP's liquidity.

Caddis and the AEP subsidiary which acts as its managing member are each a limited liability company, with a separate existence and identity from its members, and the assets of each are separate and legally distinct from AEP. The results of operations, cash flows and financial position of Caddis and such managing member are consolidated with AEP for financial reporting purposes. The preferred member interest and payments of the preferred return are reported on AEP's income statement and balance sheet as Minority Interest in Finance Subsidiary.

Expenditures for domestic electric utility construction are estimated to be $4.6 billion for the next three years. Approximately 100% of construction expenditures are expected to be financed by internally generated funds.

In 1998 SEEBOARD's 80% owned subsidiary, SEEBOARD Powerlink, signed a 30-year contract for $1.6 billion to operate, maintain, finance and renew the high-voltage power distribution network of the London Underground transportation system. SEEBOARD Powerlink will be responsible for distributing high voltage electricity to supply 270 London Underground stations and 250 miles of the rail system's track. SEEBOARD's partners in Powerlink are an international electrical engineering group and an international cable and construction group.

Financing Activity

AEP issued $1.25 billion of global notes in May 2001 (with intermediate maturities). The proceeds were loaned to regulated and non-regulated subsidiaries.

In 2001 CSPCo and OPCo, AEP's Ohio subsidiaries, reacquired $295.5 million and $175.6 million, respectively, of first mortgage bonds in preparation for corporate separation.

AEP Credit purchases, without recourse, the accounts receivable of most of the domestic utility operating companies and certain non-affiliated electric utility companies. AEP Credit's financing for the purchase of receivables changed during 2001. Starting December 31, 2001, AEP Credit entered into a sale of receivables agreement. The agreement allows AEP Credit to sell certain receivables and receive cash meeting the requirements of SFAS 140 for the receivables to be removed from the balance sheet. The agreement expires in May 2002 and is expected to be renewed. At December 31, 2001, AEP Credit had $1.0 billion sold under this agreement of which $485 million are non-affiliated receivables. In January 2002, AEP Credit stopped purchasing accounts receivables from non-affiliated electric utility companies.

In February 2002 CPL issued $797 million of securitization notes that were approved by the PUCT as part of Texas restructuring to help decrease rates and recover regulatory assets. The proceeds were used to reduce CPL's debt and equity.

In 2002 the Company plans to continue restructuring its debt for corporate separation assuming receipt of all necessary regulatory approvals. Corporate separation will require the transfer of assets between legal entities. With corporate separation, a newly created holding company for the unregulated business is expected to issue all debt needed to fund the wholesale business and unregulated generating companies. The size and maturity lengths of the original offering is presently being determined.

The regulated holding company is expected to issue the debt needed by the wires companies in Ohio and Texas. The regulated integrated utility companies will continue their current debt structure until the regulatory commissions approve changes. At that time, the regulated holding company may also issue the debt for the regulated companies' funding needs.

We have requested credit ratings for the holding companies consistent with our existing credit quality, but we cannot predict what the outcome will be.

AEP uses a money pool to meet the short-term borrowings for certain of its subsidiaries, primarily the domestic electric utility operations. Following corporate separation, management will evaluate the advantages of establishing a money pool for the unregulated business subsidiaries. The current money pool which was approved by the appropriate regulatory authorities will continue to service the regulated business subsidiaries. Presently, AEP also funds the short-term debt requirements of other subsidiaries that are not included in the money pool. As of December 31, 2001, AEP had credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2001, AEP had $2.9 billion outstanding in short-term borrowing subject to these credit facilities.

MARKET RISKS

As a major power producer and trader of wholesale electricity and natural gas, we have certain market risks inherent in our business activities. These risks include commodity price risk, interest rate risk, foreign exchange risk and credit risk. They represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Policies and procedures are established to identify, assess, and manage market risk exposures in our day to day operations. Our risk policies have been reviewed with the Board of Directors, approved by a Risk Management Committee and administered by a Chief Risk Officer. The Risk Management Committee establishes risk limits, approves risk policies, assigns responsibilities regarding the oversight and management of risk and monitors risk levels. This committee receives daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. The committee meets monthly and consists of the Chief Risk Officer, Chief Credit Officer, V.P. Market Risk Oversight, and senior financial and operating managers.

We use a risk measurement model which calculates Value at Risk (VaR) to measure our commodity price risk. 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 one-day holding period. Based on this VaR analysis, at December 31, 2001 a near term typical change in commodity prices is not expected to have a material effect on our results of operations, cash flows or financial condition.

The following table shows the high, average, and low market risk as measured by VaR at:

	December 31, 2001			December 31, 2000		
	High	Average	Low	High	Average	Low
	(in millions)					
Trading	$28	$14	$5	$32	$10	$1

We also utilize a VaR model to measure interest rate market risk exposure. 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 AEP's exposure to interest rates, primarily related to long-term debt with fixed interest rates, was $673 million at December 31, 2001 and $998 million at December 31, 2000. However, since we would not expect to liquidate our entire debt portfolio in a one year holding period, a near term change in interest rates should not materially affect results of operations or consolidated financial position.

AEP is exposed to risk from changes in the market prices of coal and natural gas used to generate electricity where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The protection afforded by fuel clause recovery mechanisms has either been eliminated by the implementation of customer choice in Ohio (effective January 1, 2001) and in the ERCOT area of Texas (effective January 1, 2002) or frozen by settlement agreements in Indiana, Michigan and West Virginia. To the extent the fuel supply of the generating units in these states is not under fixed price long-term contracts AEP is subject to market price risk. AEP continues to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas.

We employ physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. However, we engage in trading of electricity, gas and to a lesser degree coal, oil, natural gas liquids, and emission allowances and as a result the Company is subject to price risk. The amount of risk taken by the traders is controlled by the management of the trading operations and the Company's Chief Risk Officer and his staff. When the risk from trading activities exceeds certain pre-determined limits, the positions are modified or hedged to reduce the risk to the limits unless specifically approved by the Risk Management Committee.

We employ fair value hedges, cash flow hedges and swaps to mitigate changes in interest rates or fair values on short and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

We employ cash flow forward hedge contracts to lock-in prices on transactions denominated in foreign currencies where deemed necessary. International subsidiaries use currency swaps to hedge exchange rate fluctuations in debt denominated in foreign currencies. We do not hedge all foreign currency exposure.

AEP limits credit risk by extending unsecured credit to entities based on internal ratings. In addition, AEP uses Moody's Investor Service, Standard and Poor's and qualitative and quantitative data to independently assess the financial health of counterparties on an ongoing basis. This data, in conjunction with the ratings information, is used to determine appropriate risk parameters. AEP also requires cash deposits, letters of credit and parental/affiliate guarantees as security from certain below investment grade counterparties in our normal course of business.

We trade electricity and gas contracts with numerous counterparties. Since our open energy trading contracts are valued based on changes in market prices of the related commodities, our exposures change daily. We believe that our credit and market exposures with any one counterparty is not material to financial condition at December 31, 2001. At December 31, 2001 less than 5% of the counterparties were below investment grade as expressed in terms of Net Mark to Market Assets. Net Mark to Market Assets represents the aggregate difference (either positive or negative) between the forward market price for the remaining term of the contract and the contractual price. The following table approximates counterparty credit quality and exposure.

Counterparty Credit Quality: December 31, 2001	Futures, Forward and Swap Contracts	Options	Total
		(in millions)	
AAA/Exchanges	$ 147	$ -	$ 147
AA	140	4	144
A	304	7	311
BBB	932	34	966
Below Investment Grade	56	23	79
Total	$1,579	$68	$1,647

We enter into transactions for electricity and natural gas as part of wholesale trading operations. Electric and gas transactions are executed over the counter with counterparties or through brokers. Gas transactions are also executed through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers and counterparties require cash or cash related instruments to be deposited on these transactions as margin against open positions. The combined margin deposits at December 31, 2001 and 2000 was $55 million and $95 million. These margin accounts are restricted and therefore are not included in cash and cash equivalents on the Balance Sheet. We can be subject to further margin requirements should related commodity prices change.

We recognize the net change in the fair value of all open trading contracts, a practice commonly called mark-to-market accounting, in accordance with generally accepted accounting principles and include the net change in mark-to-market amounts on a net discounted basis in revenues. Unrealized mark-to-market revenues totaled $257 million in 2001. The fair values of open short-term trading contracts are based on exchange prices and broker quotes. The fair value of open long-term trading contracts are based mainly on Company developed valuation models. The valuation models produce an estimated fair value for open long-term trading contracts. This fair value is present valued and reduced by appropriate reserves for counterparty credit risks and liquidity risk. The models are derived from internally assessed market prices with the exception of the NYMEX gas curve, where we use daily settled prices. Forward price curves are developed for inclusion in the model based on broker quotes and other available market data. The curves are within the range between the bid and ask prices. The end of the month liquidity reserve is based on the difference in price between the price curve and the bid price of the bid ask prices if we have a long position and the ask side if we have a short position. This provides for a conservative valuation net of the reserves.

The use of these models to fair value open trading contracts has inherent risks relating to the underlying assumptions employed by such models. Independent controls are in place to evaluate the reasonableness of the price curve models. Significant adverse or favorable effects on future results of operations and cash flows could occur if market risks, at the time of settlement, do not correlate with the Company developed price models.

The effect on the Consolidated Statements of Income of marking to market open electricity trading contracts in the Company's regulated jurisdictions is deferred as regulatory assets or liabilities since these transactions are included in cost of service on a settlement basis for ratemaking purposes. Unrealized mark-to-market gains and losses from trading are reported as assets or liabilities.

The following table shows net revenues (revenues less fuel and purchased energy expense) and their relationship to the mark-to-market revenues (the change in fair value of open trading contracts).

	December 31, 2001	2000	1999
		(in millions)	
Revenues (including mark- to-market adjustment)	$61,257	$36,706	$24,745
Fuel and Purchased Energy Expense	52,753	28,718	17,244
Net Revenues	$ 8,504	$ 7,988	$ 7,501
Mark-to-Market Revenues	$257	$170	$23
Percentage of Net Revenues Represented by Mark-to-Market	3%	2%	-%

The following tables analyze the changes in fair values of trading assets and liabilities. The first table "Net Fair Value of Energy Trading Contracts" shows how the net fair value of energy trading contracts was derived from the amounts included in the balance sheet line item "energy trading and dervative contracts." The next table "Energy Trading Contracts" disaggregates realized and unrealized changes in fair value; identifies changes in fair value as a result of changes in valuation methodologies; and reconciles the net fair value of energy trading contracts at the beginning of the year of $63 million to the end of the year of $448 million. Contracts realized/settled during the period include both sales and purchase contracts. The third table "Energy Trading Contract Maturities" shows exposures to changes in fair values and realization periods over time for each method used to determine fair value.

Net Fair Value of Energy Trading Contracts

	December 31, 2001	December 31, 2000
	(in millions)	
Energy Trading Contracts:		
Current Asset	$ 8,536	$ 15,495
Long-term Asset	2,367	1,552
Current Liability	(8,279)	(15,671)
Long-term Liability	(2,176)	(1,313)
Net Fair Value of Energy Trading Contracts	$ 448	$ 63

The net fair value of energy trading contracts includes $257 million at December 31, 2001 and $170 million at December 31, 2000 of unrealized mark-to-market gains that are recognized in the income statement. Also included in the above net fair value of energy trading contracts are option premiums that are deferred until the related contracts settle and the portion of changes in fair values of electricity trading contracts that are deferred for ratemaking purposes.

Energy Trading Contracts
(in millions)

	Total	
Net Fair Value of Energy Trading Contracts at December 31, 2000	$ 63	
Gain from Contracts realized/settled during period	(352)	(a)
Fair Value of new open contracts when entered into during period	73	(b)
Adjustments for Contracts entered into and settled during period	310	(a)
Net option premium payments	24	
Change in fair value due to Valuation Methodology changes	(1)	(c)
Changes in market value of contracts	331	(d)
Net Fair Value of Energy Trading Contracts at December 31, 2001	$ 448	(e)

(a) Gains from Contracts Realized or Otherwise Settled During the Period" include realized gains from energy trading contracts that settled during 2001 that were entered into prior to 2001, as well as during 2001. "Adjustment for Contracts Entered into and Settled During the Period" discloses the realized gains from settled energy trading contracts that were both entered into and closed within 2001 that are included in the total gains of $352 million, but not included in the ending balance of open contracts.
(b) The "Fair Value of New Open Contracts When Entered Into during period" represents the fair value of long-term contracts entered into with customers during 2001. The fair value is calculated as of the execution of the contract. Most of the fair value comes from longer term fixed price contracts with customers that seek to limit their risk against fluctuating energy prices. The contract prices are valued against market curves representative of the delivery location.
(c) The Company changed its methodology for calculating and reporting load based transactions. The previous methodology estimated a baseload volume based on historical takes and sold a call option for potential load increases from the baseload. The current methodology uses a modified version of a straddle load follow model to estimate the baseload volume and call option volume. This methodogy change more accurately estimates the load volume forecast. The dollar impact on existing deals was a decrease of in fair value of $1.2 million.
(d) "Change in market Value of Contracts" represents the fair value change in the trading portfolio due to market fluctuations during the current period. Market fluctuations are attributable to various factors such as supply/demand, weather, storage, etc.
(e) The net change in the fair value of energy trading contracts for 2001 that resulted in an increase of $385 million ($448 million less $63 million) represents the balance sheet change. The net mark-to-market gain on energy trading contracts of $257 million represents the impact on earnings. The difference is related primarily to regulatory deferrals of certain mark-to-market gains that were recorded as regulatory liabilities and not reflected in the income statement for those companies that operate in regulated jurisdictions, and deferrals of option premiums included in the above analysis, which do not have a mark-to-market income statement impact.

Energy Trading Contract Maturities
(in millions)

	Fair Value of Contracts at December 31,2001 Maturities				
Source of Fair Value	Less than 1 year	1-3 years	4-5 years	In Excess Of 5 years	Total Fair Value
Prices actively quoted (a)	$ 46	$ 8	$ -	$ -	$ 54
Prices provided by other external Sources (b)	152	33	-	-	185
Prices based on models and other valuation methods (c)	13	133	35	28	209
Total	$211	$174	$35	$28	$448

(a) "Prices Actively Quoted" represents the Company's exchange traded futures positions in natural gas.
(b) "Prices Provided by Other External Sources" represents the Company's positions in natural gas, power, and coal at points where over-the-counter broker quotes are available. Prices for these various commodities can generally be obtained on the over-the-counter market through 2003. Some prices from external sources are quoted as strips (one bid/ask for Nov-Mar, Apr-Oct, etc). Such transactions have also been included in this category.
(c) "Prices Based on Models and Other Valuation Methods" contain the following: the value of the Company's adjustments for liquidity and counterparty credit exposure, the value of contracts not quoted by an exchange or an over-the-counter broker, the value of transactions for which an internally developed price curve was developed as a result of the long dated nature of certain transactions, and the value of certain structured transactions.

We have investments in debt and equity securities which are held in nuclear trust funds. The trust investments and their fair value are discussed in Note 13, "Risk Management, Financial Instruments and Derivatives." Financial instruments in these trust funds have not been included in the market risk calculation for interest rates as these instruments are marked-to-market and changes in market value of these instruments are reflected in a corresponding decommissioning liability. Any differences between the trust fund assets and the ultimate liability are expected to be recovered through regulated rates from our regulated customers.

Inflation affects our cost of replacing utility plant and the cost of operating and maintaining plant. The rate-making process limits 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

AEP is involved in various litigation. The details of significant litigation contingencies are disclosed in Note 8 and summarized below.

COLI

A decision by U.S. District Court for the Southern District of Ohio in February 2001 that denied AEP's deduction of interest claimed on AEP's federal income tax returns related to its COLI program resulted in a $319 million reduction in net income for 2000. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 the Company paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets pending the resolution of this matter. The Company has appealed the Court's decision.

Shareholders' Litigation

On December 21, 2001, the U.S. District Court for the Southern District of Ohio dismissed a class action lawsuit against AEP and four former or present officers. The complaint alleged violation of federal securities laws by disseminating materially false and misleading statements related to the extended Cook Plant outage.

FERC Wholesale Fuel Complaints

In November 2001 certain WTU wholesale customers filed a complaint with FERC alleging that WTU has overcharged them since 1997 through the fuel adjustment clause. The customers allege inappropriate costs related to purchased power were included in the fuel adjustment clause. Management is working to compute if any overcharges occurred and is unable to predict their impact on results of operations, cash flow and financial condition.

Municipal Franchise Fee Litigation

In 2001 CPL paid $11 million to settle class action litigation regarding municipal franchise fees in Texas. The City of San Juan, Texas had filed a class action lawsuit in 1996 seeking $300 million in damages.

Texas Base Rate Litigation

In 2001 the Texas Supreme Court denied CPL's request for the court to review a 1997 PUCT base rate order. Subsequently the Court also denied CPL's rehearing request.

The primary issues CPL requested the Court to review were:

- the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property;
- and an $18 million disallowance of affiliated service billings.

Lignite Mining Agreement Litigation

In 2001 SWEPCo settled litigation concerning lignite mining in Louisiana. Since 1997 SWEPCo has been involved in litigation concerning the mining of lignite from jointly owned lignite reserves. SWEPCo and

CLECO, an unaffiliated utility, are each a 50% owner of the Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. Under terms of a settlement, SWEPCo purchased an unaffiliated mine operator's interest in the mining operations and related debt and other obligations for $86 million.

Merger Litigation

In January 2002, a federal court ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Other

AEP 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.

INTERNATIONAL INVESTMENTS

We own a 44% equity interest in Vale, a Brazilian electric operating company which was purchased for a total of $149 million. On December 1, 2001 we converted a $66 million note receivable and accrued interest into a 20% equity interest in Caiua (Brazilian electric operating company), a subsidiary of Vale. Vale and Caiua have experienced losses from operations and our investment has been affected by the devaluation of the Brazilian Real. The cumulative equity share of operating and foreign currency translation losses through December 31, 2001 is approximately $46 million and $54 million, respectively net of tax. The cumulative equity share of operating and foreign currency translation losses through December 31, 2000 is approximately $33 million and $49 million, respectively net of tax. Both investments are covered by a put option, which, if exercised, requires our partners in Vale to purchase our Vale and Caiua shares at a minimum price equal to the U.S. dollar equivalent of the original purchase price. As a result, management has concluded that the investment carrying amount should not be reduced below the put option value unless it is deemed to be an other than temporary impairment and our partners in Vale are deemed unable to fulfill their responsibilities under the put option. Management has evaluated through an independent third-party, the ability of its Vale partners to fulfill their responsibilities under the put option agreement and has concluded that our partners should be able to fulfill their responsibilities.

Management believes that the decline in the value of its investment in Vale in US dollars is not other than temporary. As a result and pursuant to the put option agreement, these losses have not been applied to reduce the carrying values of the Vale and Caiua investments. As a result we will not recognize any future earnings from Vale and Caiua until the operating losses are recovered. Should the impairment of our investment become other than temporary due to our partners in Vale becoming unable to fulfill their responsibilities, it would have an adverse effect on future results of operations.

Management will continue to monitor both the status of the losses and the ability of its partners to fulfill their obligations under the put.

ENVIRONMENTAL CONCERNS AND ISSUES

The U.S. continues to debate an array of environmental issues affecting the electric utility industry including new emission limitations recommend by the Bush Administration in February 2002. Most of the policies are aimed at reducing air emissions citing alleged impacts of such emissions on public health, sensitive ecosystems or the global climate.

AEP's policy on the environment continues to be the development and application of long-term economically feasible measures to improve air and water quality, limit emissions and protect the health of its employees, customers, neighbors and others impacted by its operations. In support of this policy, AEP continues to invest in research through groups like the Electric Power Research Institute and directly through demonstration projects for new technology for the capture and storage of carbon dioxide, mercury, NOx and other emissions. AEP intends to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to our customers at fair prices.

AEP has a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. AEP and its subsidiaries have spent billions of dollars to equip their facilities with the latest cost effective clean air and water technologies and to research new technologies. We are proud of our award winning efforts to reclaim our mining properties.

The introduction of multi-pollutant control legislation is being discussed by members of Congress and the Bush Administration. The legislation being considered may regulate carbon dioxide, NOx, sulfur dioxide, mercury and other emissions from electric generating plants. Management will continue to support solutions which are based on sound science, economics and demonstrated control technologies. Management is unable to predict the timing or magnitude of additional pollution control laws or regulations. If additional control technology is required on AEP's facilities and their costs were not recoverable from ratepayers or through market based prices or volumes of product sold, they could adversely affect future results of operations and cash flows. The following discussions explain existing control efforts, litigation and other pending matters related to environmental issues for AEP companies.

Federal EPA Complaint and Notice of Violation

Since 1999 AEP has been involved in litigation regarding generating plant emissions under the Clean Air Act. Federal EPA, a number of states and certain special interest groups alleged that AEP companies modified certain generating units over a 20 year period in violation of the Clean Air Act.

Under the Clean Air Act, if a 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. We believe our maintenance, repair and replacement activities were in conformity with the Clean Air Act and intend to vigorously pursue our defense.

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). In March 2001 the District Court ruled that claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

Management is unable to estimate a loss or predict the timing of the resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. If we do 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.

An unaffiliated utility which operates certain plants jointly owned by CSPCo reached a tentative agreement to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing and a settlement could impact the operation of the Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its future results of operations and cash flows.

NOx Reduction

Federal EPA issued a rule (the NOx Rule) and granted petitions filed by certain northeastern states (the Section 126 Rule) requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which AEP's generating plants are located.

Federal EPA ruled that eleven states, including certain states in which AEP's generating units are located, failed to submit approvable plans to comply with the NOx Rule. This ruling means that those states could face stringent sanctions including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs. A request for the D.C. Circuit Court to review this ruling is pending. The compliance date for the NOx Rule is May 31, 2004.

The D.C. Circuit Court instructed Federal EPA to justify methods used to allocate allowances and project growth for both the NOx Rule and the Section 126 Rule. In response to AEP and other utilities request for the D.C. Circuit Court to suspend the May 2003 compliance date of the Section 126 Rule, the D.C. Circuit Court issued an order tolling the compliance schedule until Federal EPA responds to the Court's remand.

In April 2000 the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including those owned by CPL and SWEPCo. The compliance date is May 2003 for CPL and May 2005 for SWEPCo.

In 2001 selective catalytic reduction (SCR) technology to reduce NOx emissions on OPCo's Gavin Plant commenced operation. Construction of SCR technology at certain other AEP generating units continues with completion scheduled in 2002 through 2006.

Our estimates indicate that compliance with the NOx Rule, the Texas Natural Resource Conservation Commission rule and the Section 126 Rule could result in required capital expenditures totaling approximately $1.6 billion of which approximately $450 million has been spent. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the preliminary estimates depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers, they will have an adverse effect on future results of operations, cash flows and possibly financial condition.

Superfund

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, 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, PCBs and other hazardous and nonhazardous materials. We are currently incurring costs to safely dispose of these substances. Additional costs could be incurred to comply with new laws and regulations if enacted.

Superfund addresses clean-up of hazardous substances at disposal sites and authorized Federal EPA to administer the clean-up programs. As of year-end 2001, subsidiaries of AEP have been named by the Federal EPA as a PRP for five sites. There are four additional sites for which AEP has received information requests which could lead to PRP designation. AEP has also been named a PRP at two sites under state law. Our liability has been resolved for a number of sites with no significant effect on results of operations. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Unfortunately, Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories.

While the potential liability for each Superfund site must be evaluated separately, several general statements can be made regarding our potential future liability. AEP's disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was small and often nonhazardous. Although liability is joint and several, typically many parties are named as PRPs for each site and several of the other parties are financially sound enterprises. Therefore, our present estimates do not anticipate material cleanup costs for identified sites for which we have been declared PRPs. If significant cleanup costs are attributed to AEP in the future under Superfund which cannot be recovered from customers, results of operations, cash flows and possibly financial condition would be adversely affected.

Global Climate Change

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. Although the U.S. signed the Kyoto Protocol on November 12, 1998, the treaty was not submitted to the Senate for its advice and consent by President Clinton. In March 2001 President Bush announced his opposition to the treaty and its U.S. ratification. At the Seventh Conference of the Parties in November 2001, the parties finalized the rules, procedures and guidelines required to facilitate ratification of the protocol. The protocol is expected to become effective by 2003. U.S. representatives attended the Seventh Conference but they did not take any positions on issues being negotiated or attempt to block the approval of any issue. AEP does not support the Kyoto Protocol but intends to work with the Bush Administration and U.S. Congress to develop responsible public policy on this issue. Management expects due to President Bush's opposition to legislation mandating green-house gas emissions controls, any policies developed and implemented in the near future are likely to encourage voluntary measures to reduce, avoid or sequester such emissions.

The acquisition of 4,000 MW of coal-fired generation in the United Kingdom in December 2001 exposes these assets to potential carbon dioxide emission control obligations since the U.K. is expected to be a party to the Kyoto Protocol.

Costs for Spent Nuclear Fuel and Decommissioning

AEP, as the owner of the Cook Plant and as a partial owner of STP, has a significant future financial commitment to safely dispose of SNF and decommission and decontaminate the plants. 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 DOE's SNF disposal program which is described in Note 8 of the Notes to Consolidated Financial Statements. Since 1983 I&M has collected $288 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $116 million of these funds have been deposited in external trust funds to provide for the future disposal of spent nuclear fuel and $172 million has been remitted to the DOE. CPL has collected and remitted to the DOE, $49 million for the future disposal of SNF since STP began operation in the late 1980s. 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 1996, the DOE notified AEP 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, AEP on behalf of I&M and STPNOC on behalf of CPL and the other STP owners, along with a number of unaffiliated utilities and states, filed suit in the D.C. Circuit Court requesting, among other things, that the D.C. Circuit Court order DOE to meet its obligations under the law. The D.C. Circuit 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, AEP 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. In August 2000, in an appeal of related cases involving other unaffiliated utilities, the U.S. Court of Appeals for the Federal Circuit held that the delays clause of the standard contract between utilities and the DOE did not apply to DOE's complete failure to perform its contract obligations, and that the utilities' suits against DOE may continue in court. AEP's suit has been stayed pending further action by the U.S. Court of Federal Claims. 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 and the cost of decommissioning will continue to increase.

In January 2001, I&M and STPNOC, on behalf of STP's joint owners, joined a lawsuit against DOE, filed in November 2000 by unaffiliated utilities, related to DOE's nuclear waste fund cost recovery settlement with PECO Energy Corporation. The settlement allows PECO to skip two payments to the DOE for disposal of SNF due to the lack of progress towards development of a permanent repository for SNF. The companies believe the settlement is unlawful as the settlement would force other utilities to make up any shortfall in DOE's SNF disposal funds.

The cost to decommission nuclear plants is affected by both NRC regulations and the delayed SNF disposal program. Studies completed in 2000 estimate the cost to decommission the Cook Plant ranges from $783 million to $1,481 million in 2000 non-discounted dollars. External trust funds have been established with amounts collected from customers to decommission the plant. At December 31, 2001, the total decommissioning trust fund balance for Cook Plant was $598 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate CPL's share of decommissioning cost to be $289 million in 1999 non-discounted dollars. Amounts collected from customers to decommission STP have been placed in an external trust. At December 31, 2001, the total decommissioning trust fund for CPL's share of STP was $99 million which includes earnings on the trust investments. Estimates from the decommissioning studies could continue to escalate due to the uncertainty in the SNF disposal program and the length of time that SNF may need to be stored at the plant site. We will work with regulators and customers to recover the remaining estimated costs of decommissioning Cook Plant and STP. However, AEP's future results of operations, cash flows and possibly its financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

The Company is exposed to other environmental concerns which are not considered to be material or potentially material at this time. Should they become significant or should any new concerns be uncovered that are material they could have a material adverse effect on results of operations and possibly financial condition. AEP performs environmental reviews and audits on a regular basis for the purpose of identifying, evaluating and addressing environmental concerns and issues.

APCo, AEP's subsidiary which operates in Virginia and West Virginia, has been seeking regulatory approval to build a new high voltage transmission line for over a decade. Through December 31, 2001 we have invested approximately $40 million in this effort. If the required regulatory approvals are not obtained and the line is not constructed, the $40 million investment would be written off adversely affecting future results of operations and cash flows.

ENRON BANKRUPTCY

At the date of Enron's bankruptcy AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line from Enron and entered into a lease arrangement with a subsidiary of Enron for a gas storage facility. At the date of Enron's bankruptcy various HPL related contingencies and indemnities remained unsettled. In the fourth quarter of 2001 AEP provided $47 million ($31 million net of tax) for our estimated losses from the Enron bankruptcy. The amount provided was based on an analysis of contracts where AEP and Enron are counterparties, the offsetting of receivables and payables, the application of deposits from Enron and management's analysis of the HPL related purchase contingencies and indemnifications. If there are any adverse unforeseen developments in the bankruptcy proceedings, our future results of operations, cash flows and possibly financial condition could be adversely impacted.

INVESTMENTS LIMITATIONS

Our investment, including guarantees of debt, in certain types of activities is limited by PUHCA. SEC authorization under PUHCA limits us to issuing and selling securities in an amount up to 100% of our average quarterly consolidated retained earnings balance for investment in EWGs and FUCOs. At December 31, 2001, AEP's investment in EWGs and FUCOs was $2.9 billion, including guarantees of debt, compared to AEP's limit of $3.3 billion.

SEC rules under PUHCA permit AEP to invest up to 15% of consolidated capitalization (such amount was $3.6 billion at December 31, 2001) in energy-related companies, including marketing and/or trading of electricity, gas and other energy commodities. Our gas trading business and our interest in domestic cogeneration projects are reported as investments under this rule and at December 31, 2001, such investment was $2.2 billion.

OTHER MATTERS

New Accounting Standards

The FASB recently issued SFAS 141, "Business Combinations" and SFAS 142, "Goodwill And Other Intangible Assets." SFAS 141 requires that the purchase method of accounting be used to account for all business combinations entered into after June 30, 2001. SFAS 142 requires that goodwill amortization cease and that goodwill and other intangible assets with indefinite lives be tested for impairment upon SFAS 142 implementation and annually thereafter. These new standards must be implemented by AEP in the first quarter of 2002. Amortization of goodwill and other intangible assets with indefinite lives will cease with our implementation of SFAS 142 beginning January 1, 2002. The amortization of goodwill and other intangible assets reduced our net income by $50 million for the twelve months ended December 31, 2001. We are currently in the process of fair valuing our reporting units with goodwill in order to determined potential goodwill impairment. As such we have not yet determined the impact on first quarter 2002 results of operations adopting the provision of these standards.

SFAS 143, "Accounting for Asset Retirement Obligations," will become effective for us beginning January 1, 2003. SFAS 143 established accounting and reporting for legal obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. We are currently in the process of evaluating the provisions of the standard and determining its impact on future results of operations and financial condition. To the extent AEP is a regulated entity we anticipate that the cumulative effect of this accounting change on future results of operations will be significantly offset by a regulatory asset representing the right to recover legal ARO obligations relative to regulated long lived assets included in rate base. The impact on future results of operations from the implementation of this new standard on the Company's non-regulated long lived assets has not yet been determined. We anticipate that the considerable effort to identify all long lived assets with legal ARO and to determine the required discounted legal ARO obligation will take the remainder of 2002.

In August 2001 the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets" which sets forth the accounting to recognize and measure an impairment loss. This standard replaces the previous standard, SFAS 121, "Accounting for the Long-lived Assets and for Long-lived Assets to be Disposed Of." SFAS 144 will apply to us beginning January 1, 2002. We do not expect that the implementation of SFAS 144 will materially affect results of operations or financial condition.

The FASB recently revised its prior guidance related to SFAS 133, "Accounting for Deriviative Instruments and Hedging Activities" with regard to certain power option and forward contracts. The revised guidance states that power contracts, including both forward and option contracts, that include certain qualitative characteristics are considered capacity contracts, and qualify for the normal purchases and normal sales exception from being marked to market even if they are subject to being booked out, or scheduled to be booked out. As normal purchases and sales these open energy contracts are not marked to market. Rather they are accounted for on a settlement basis. Most of AEP's power contracts that are not marked to market as trading transactions do not qualify as derivatives and thus are not subject to the revised guidance. The few contracts that are derivatives qualified for the exception under the previous guidance and will continue to qualify under the new guidance.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
(in millions - except per share amounts)

	Year Ended December 31,		
	2001	2000	1999
REVENUES:			
Electricity Marketing and Trading	$41,513	$25,178	$17,232
Gas Marketing and Trading	14,416	6,259	2,311
Domestic Electricity Delivery	3,356	3,174	3,068
Other Investments	1,972	2,095	2,134
TOTAL REVENUES	61,257	36,706	24,745
EXPENSES:			
Fuel and Purchased Energy:			
Electricity Marketing and Trading	37,558	21,246	13,646
Gas Marketing and Trading	14,004	6,227	2,305
Other Investments	1,191	1,245	1,293
TOTAL FUEL AND PURCHASED ENERGY	52,753	28,718	17,244
Maintenance and Other Operation	4,037	3,841	3,276
Non-recoverable Merger Costs	21	203	-
Depreciation and Amortization	1,383	1,250	1,212
Taxes Other Than Income Taxes	668	690	709
TOTAL EXPENSES	58,862	34,702	22,441
OPERATING INCOME	2,395	2,004	2,304
OTHER INCOME	302	136	202
OTHER EXPENSES	130	81	42
LESS: INTEREST	972	1,149	977
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	10	11	19
MINORITY INTEREST IN FINANCE SUBSIDIARY	13	-	-
INCOME BEFORE INCOME TAXES	1,572	899	1,468
INCOME TAXES	569	597	482
INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT	1,003	302	986
EXTRAORDINARY LOSSES (NET OF TAX):			
DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION	(48)	(35)	(8)
LOSS ON REACQUIRED DEBT	(2)	-	(6)
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (net of tax)	18	-	-
NET INCOME	$ 971	$ 267	$ 972
AVERAGE NUMBER OF SHARES OUTSTANDING	322	322	321
EARNINGS PER SHARE:			
Income Before Extraordinary Item and Cumulative Effect	$ 3.11	$ 0.94	$ 3.07
Extraordinary Losses	(0.16)	(0.11)	(0.04)
Cumulative Effect of Accounting Change	0.06	-	-
Earnings Per Share (Basic and Dilutive)	$ 3.01	$ 0.83	$ 3.03
CASH DIVIDENDS PAID PER SHARE	$2.40	$2.40	$2.40

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(in millions - except share data)

	December 31, 2001	December 31, 2000
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 333	$ 342
Accounts Receivable:		
Customers	626	888
Miscellaneous	1,365	2,883
Allowance for Uncollectible Accounts	(109)	(72)
Energy Trading and Derivative Contracts	8,572	15,497
Other	1,776	1,363
TOTAL CURRENT ASSETS	12,563	20,901
PROPERTY, PLANT AND EQUIPMENT:		
Electric:		
Production	17,477	16,328
Transmission	5,879	5,609
Distribution	11,310	10,843
Other (including gas assets and nuclear fuel)	4,941	4,077
Construction Work in Progress	1,102	1,231
Total Property, Plant and Equipment	40,709	38,088
Accumulated Depreciation and Amortization	16,166	15,695
NET PROPERTY, PLANT AND EQUIPMENT	24,543	22,393
REGULATORY ASSETS	3,162	3,698
INVESTMENTS IN POWER, DISTRIBUTION AND COMMUNICATIONS PROJECTS	677	782
GOODWILL (NET OF AMORTIZATION)	1,494	1,382
LONG-TERM ENERGY TRADING AND DERIVATIVE CONTRACTS	2,370	1,552
OTHER ASSETS	2,472	2,642
TOTAL	$47,281	$53,350

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(in millions - except share data)

	December 31, 2001	December 31, 2000
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts Payable	$ 2,245	$ 2,627
Short-term Debt	3,155	4,333
Long-term Debt Due Within One Year*	2,300	1,152
Energy Trading and Derivative Contracts	8,311	15,671
Other	2,088	2,154
TOTAL CURRENT LIABILITIES	18,099	25,937
LONG-TERM DEBT*	9,753	9,602
LONG-TERM ENERGY TRADING AND DERIVATIVE CONTRACTS	2,183	1,313
DEFERRED INCOME TAXES	4,823	4,875
DEFERRED INVESTMENT TAX CREDITS	491	528
DEFERRED CREDITS AND REGULATORY LIABILITIES	948	637
DEFERRED GAIN ON SALE AND LEASEBACK – ROCKPORT PLANT UNIT 2	194	203
OTHER NONCURRENT LIABILITIES	1,334	1,706
COMMITMENTS AND CONTINGENCIES (Note 8)		
CERTAIN SUBSIDIARY OBLIGATED, MANDATORILY REDEEMABLE, PREFERRED SECURITIES OF SUBSIDIARY TRUSTS HOLDING SOLELY JUNIOR SUBORDINATED DEBENTURES OF SUCH SUBSIDIARIES	321	334
MINORITY INTEREST IN FINANCE SUBSIDIARY	750	-
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES*	156	161
COMMON SHAREHOLDER'S EQUITY:		
Common Stock-Par Value $6.50: (2001 / 2000) Shares Authorized. . . 600,000,000 / 600,000,000; Shares Issued. . . . . 331,234,997 / 331,019,146 (8,999,992 shares were held in treasury at December 31, 2001 and 2000)	2,153	2,152
Paid-in Capital	2,906	2,915
Accumulated Other Comprehensive Income (Loss)	(126)	(103)
Retained Earnings	3,296	3,090
TOTAL COMMON SHAREHOLDERS' EQUITY	8,229	8,054
TOTAL	$47,281	$53,350

*See Accompanying Schedules.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31,		
	2001	2000	1999
OPERATING ACTIVITIES:			
Net Income	$ 971	$ 267	$ 972
Adjustments for Noncash Items:			
Depreciation and Amortization	1,413	1,299	1,294
Deferred Federal Income Taxes	163	(170)	180
Deferred Investment Tax Credits	(29)	(36)	(38)
Amortization (Deferral) of Operating Expense and Carrying Charges (net)	40	48	(151)
Equity in Earnings of Yorkshire Electricity Group plc	-	(44)	(45)
Extraordinary Loss	50	35	14
Cumulative Effect of Accounting Change	(18)	-	-
Deferred Costs Under Fuel Clause Mechanisms	340	(449)	(191)
Mark to Market of Energy Trading Contracts	(257)	(170)	(23)
Miscellaneous Accrued Expenses	(384)	217	101
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	1,764	(1,632)	(80)
Fuel, Materials and Supplies	(82)	147	(162)
Accrued Utility Revenues	26	(79)	(35)
Accounts Payable	(461)	1,322	74
Taxes Accrued	(147)	172	29
Option Premiums	(76)	74	8
Payment of Disputed Tax and Interest Related to COLI	-	319	(16)
Change in Other Assets	(213)	(92)	(87)
Change in Other Liabilities	(147)	205	(245)
Net Cash Flows From Operating Activities	2,953	1,433	1,599
INVESTING ACTIVITIES:			
Construction Expenditures	(1,832)	(1,773)	(1,680)
Purchase of Houston Pipe Line	(727)	-	-
Purchase of U.K. Generation	(943)	-	-
Purchase of Quaker Coal Co.	(101)	-	-
Purchase of Memco	(266)	-	-
Purchase of Indian Mesa	(175)	-	-
Sale of Yorkshire	383	-	-
Sale of Frontera	265	-	-
Other	(36)	19	7
Net Cash Flows Used For Investing Activities	(3,432)	(1,754)	(1,673)
FINANCING ACTIVITIES:			
Issuance of Common Stock	10	14	93
Issuance of Minority Interest	747	-	-
Issuance of Long-term Debt	2,931	1,124	1,391
Retirement of Cumulative Preferred Stock	(5)	(20)	(170)
Retirement of Long-term Debt	(1,835)	(1,565)	(915)
Change in Short-term Debt (net)	(597)	1,308	812
Dividends Paid on Common Stock	(773)	(805)	(833)
Dividends on Minority Interest in Subsidiary	(5)	-	-
Other Financing Activities	-	-	(43)
Net Cash Flows From Financing Activities	473	56	335
Effect of Exchange Rate Change on Cash	(3)	23	(2)
Net Increase (Decrease) in Cash and Cash Equivalents	(9)	(242)	259
Cash and Cash Equivalents January 1	342	584	325
Cash and Cash Equivalents December 31	$ 333	$ 342	$ 584

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(in millions)

	Common Shares	Stock Amount	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
JANUARY 1, 1999	328	$2,134	$2,818	$3,493	$ 7	$8,452
Issuances	3	15	77	-	-	92
Retirements and Other	-	-	3	-	-	3
Cash Dividends Declared	-	-	-	(833)	-	(833)
Other	-	-	-	(2)	-	(2)
						7,712
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	(13)	(13)
Minimum Pension Liability	-	-	-	-	2	2
Net Income	-	-	-	972	-	972
Total Comprehensive Income						961
DECEMBER 31, 1999	331	2,149	2,898	3,630	(4)	8,673
Issuances	-	3	11	-	-	14
Cash Dividends Declared	-	-	-	(805)	-	(805)
Other	-	-	6	(2)	-	4
						7,886
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	(119)	(119)
Reclassification Adjustment For Loss Included in Net Income	-	-	-	-	20	20
Net Income	-	-	-	267		267
Total Comprehensive Income						168
DECEMBER 31, 2000	331	2,152	2,915	3,090	(103)	$8,054
Issuances	-	1	9	-	-	10
Cash Dividends Declared	-	-	-	(773)	-	(773)
Other	-	-	(18)	8	-	(10)
						7,281
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	(14)	(14)
Unrealized Gain (Loss) on Derivatives Designated as Cash Flow Hedges					(3)	(3)
Minimum Pension Liability	-	-	-	-	(6)	(6)
Net Income	-	-	-	971		971
Total Comprehensive Income						948
DECEMBER 31, 2001	331	$2,153	$2,906	$3,296	$(126)	$8,229

See Notes to Consolidated Financial Statements.

1. Significant Accounting Policies:

Business Operations – AEP's eleven domestic electric utility operating companies generate and deliver energy for sale to retail and wholesale customers. These companies are subject to regulation by the FERC under the Federal Power Act and follow the Uniform System of Accounts prescribed by FERC. They are subject to further regulation with regard to rates and other matters by state regulatory commissions.

AEP also engages in wholesale marketing and trading of electricity, natural gas and to a lesser extent coal, oil, natural gas liquids and emission allowances in the United States and Europe. In addition the Company's domestic operations includes non-regulated independent power and cogeneration facilities, coal mining and intra-state midstream natural gas operations in Louisiana and Texas.

International operations include regulated supply and distribution of electricity and other non-regulated power generation projects in the United Kingdom, Australia, Mexico, South America and China.

The Company also operates domestic barging, provides energy services worldwide and furnishes communications related services domestically.

Rate Regulation – AEP is subject to regulation by the SEC under the PUHCA. The rates charged by the domestic utility subsidiaries are approved by the FERC and the state utility commissions. The FERC regulates wholesale electricity operations and transmission rates and the state commissions regulate retail rates. The prices charged by foreign subsidiaries located in the UK, Australia, China, Mexico and Brazil are regulated by the authorities of that country and are generally subject to price controls.

Principles of Consolidation - The consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned subsidiaries. Significant intercompany items are eliminated in consolidation. Equity investments that are 50% or less owned are accounted for using the equity method with their equity earnings included in Other Income.

Basis of Accounting - As the owner of cost-based rate-regulated electric public utility companies, AEP Co., Inc.'s consolidated 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 SFAS 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues. Application of SFAS 71 for the generation portion of the business was discontinued as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by CPL, WTU, and SWEPCo in September 1999 and in Arkansas by SWEPCo in September 1999. See Note 7, "Customer Choice and Industry Restructuring" for additional information.

Use of Estimates - The preparation of these financial statements in conformity with generally accepted accounting principles necessarily includes the use of estimates and assumptions by management. Actual results could differ from those estimates.

Property, Plant and Equipment – Electric utility property, plant and equipment of the domestic electric utility operating companies are stated at original cost of the acquirer. Property, plant and equipment of the non-regulated domestic operations and other investments are stated at their fair market value at acquisition plus the original cost of property acquired or constructed since the acquisition, less disposals. Additions, major replacements and betterments are added to the plant accounts. For cost-based rate regulated operations, retirements from the plant accounts and associated removal costs, net of salvage, are deducted from accumulated depreciation. The costs of labor, materials and overheads incurred to operate and maintain plant are included in operating expenses.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization - AFUDC is a noncash nonoperating income item that is capitalized and recovered through depreciation over the service life of domestic regulated electric utility plant. It represents the estimated cost of borrowed and equity funds used to finance construction projects. The amounts of AFUDC for 2001, 2000 and 1999 were not significant. Effective with the discontinuance of the application of SFAS 71 regulatory accounting for domestic generating assets in Arkansas, Ohio, Texas, Virginia and West Virginia and for other non-regulated operations, interest is capitalized during construction in accordance with SFAS 34, "Capitalization of Interest Costs." The amounts of interest capitalized were not material in 2001, 2000, and 1999.

Depreciation, Depletion and Amortization - Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of property, other than coal-mining property, and is calculated largely through the use of composite rates by functional class as follows:

Functional Class of Property	Annual Composite Depreciation Rates Ranges 2001
Production:	
Steam-Nuclear	2.5% to 3.4%
Steam-Fossil-Fired	2.5% to 4.5%
Hydroelectric-Conventional and Pumped Storage	1.9% to 3.4%
Transmission	1.7% to 3.1%
Distribution	2.7% to 4.2%
Other	1.8% to 15.0%

Functional Class of Property	Annual Composite Depreciation Rates Ranges 2000
Production:	
Steam-Nuclear	2.8% to 3.4%
Steam-Fossil-Fired	2.3% to 4.5%
Hydroelectric-Conventional and Pumped Storage	1.9% to 3.4%
Transmission	1.7% to 3.1%
Distribution	3.3% to 4.2%
Other	2.5% to 7.3%

Functional Class of Property	Annual Composite Depreciation Rates Ranges 1999
Production:	
Steam-Nuclear	2.8% to 3.4%
Steam-Fossil-Fired	3.2% to 5.0%
Hydroelectric- Conventional and Pumped Storage	1.9% to 3.4%
Transmission	1.7% to 2.7%
Distribution	2.8% to 4.2%
Other	2.0% to 20.0%

Depreciation, depletion and amortization of coal-mining assets is provided over each asset's estimated useful life or the estimated life of the mine, whichever is shorter, and is calculated using the straight-line method for mining structures and equipment. The units-of-production method is used to amortize coal rights and mine development costs based on estimated recoverable tonnages at a current average rate of $3.46 per ton in 2001, $5.07 per ton in 2000, $2.32 per ton in 1999. These costs are included in the cost of coal charged to fuel expense.

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

Inventory – Except for CPL, PSO and WTU, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. CPL, PSO and WTU utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is un-regulated, inventory of coal and oil is carried at the lower of cost or market. Coal mine inventories are also carried at the lower of cost or market. Natural gas inventories are marked-to-market if held in connection with trading operations. Any non-trading gas inventory is carried at the lower of cost or market.

Accounts Receivable – AEP Credit Inc. (formerly CSW Credit) factors accounts receivable for the domestic utility subsidiaries and certain non-affiliated utilities. In January 2002 AEP Credit stopped purchasing accounts receivable from non-affiliated utilities. On December 31, 2001 AEP Credit, Inc. entered into a sale of receivables agreement with a group of banks and commercial paper conduits. This transaction constitutes a sale of receivables in accordance with SFAS 140, allowing the receivables to be taken off of the companies' balance sheets. See Note 19, "Lines of Credit and Sale of Receivables" for further details.

Foreign Currency Translation - The financial statements of subsidiaries outside the U.S. which are included in AEP's consolidated financial statements are measured using the local currency as the functional currency and translated into U.S. dollars in accordance with SFAS 52 "Foreign Currency Translation". Assets and liabilities are translated to U.S. dollars at year-end rates of exchange and revenues and expenses are translated at monthly average exchange rates throughout the year. Currency translation gain and loss adjustments are recorded in shareholders' equity as "Accumulated Other Comprehensive Income (Loss)". The non-cash impact of the changes in exchange rates on cash, resulting from the translation of items at different exchange rates is shown on AEP's Consolidated Statement of Cash Flows in "Effect of Exchange Rate Change on Cash." Actual currency transaction gains and losses are recorded in income.

Deferred Fuel Costs - The cost of fuel consumed is charged to expense when the fuel is burned. Where applicable under governing state regulatory commission retail rate orders, fuel cost over or under-recoveries are deferred as regulatory liabilities or regulatory assets in accordance with SFAS 71. These deferrals generally are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amount of deferred fuel costs under fuel clauses for AEP was $139 million at December 31, 2001 and $407 million at December 31, 2000. See also Note 6 "Effects of Regulation".

We are protected from fuel cost changes in Kentucky for KPCo, the SPP area of Texas, Louisiana and Arkansas for SWEPCo, Oklahoma for PSO and Virginia for APCo. Where fuel clauses have been eliminated due to the transition to market pricing, (Ohio effective January 1, 2001 and in the Texas ERCOT area effective January 1, 2002) changes in fuel costs impact earnings. In other state jurisdictions, (Indiana, Michigan and West Virginia) where fuel clauses have been frozen or suspended for a period of years, fuel cost changes also impact earnings currently. This is also true for certain of AEP's Independent Power Producer generating units that do not have long-term contracts for their fuel supply. See Note 5, "Rate Matters" and Note 7, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

Revenue Recognition – We recognize revenues from foreign and domestic generation, transmission and distribution of electricity, domestic gas pipeline and storage services, other energy supply related business activities, as well as domestic barging, telecommunications and related services. The revenues associated with these activities are recorded when earned as physical commodities are delivered to contractual meter points or services are provided. These revenues also include the accrual of earned, but unbilled and/or not yet metered revenues. Such revenues are based on contract prices or tariffs and presented on a gross basis consistent with genrally accepted accounting principles and industry practice. Revenue recognition for energy marketing and trading transactions is further discussed within the *Energy Marketing and Trading Transactions* section below. The Company follows EITF 98-10 and marks to market energy trading activities, which includes the net change in fair value of open trading contracts in earnings. Mark-to-market gains and losses on open contracts and net settlements of financial contracts (see below) are included in revenues on a net basis. The net basis of reporting for open contracts is permitted by EITF 98-10 and for settled financial contracts is consistent with industry practice. Settled physical forward trading transactions are reported on a gross basis, as permitted by EITF 98-10. Management believes that the gross basis of reporting for settled physical forward trading contracts is a better indication of the scope and significance of energy trading activities to the Company.

Energy Marketing and Trading Transactions - The Company engages in wholesale electricity and natural gas marketing and trading transactions (trading activities). Trading activities involve the purchase and sale of energy under forward contracts at fixed and variable prices and the trading of financial energy contracts which includes exchange futures and options and over-the-counter options and swaps. Although trading contracts are generally short-term, there are long-term trading contracts.

The majority of trading activities represent forward electricity and gas contracts that are typically settled by entering into offsetting physical contracts. Forward trading sale contracts are included in revenues when the contracts settle. Forward trading purchase contracts are included in fuel and purchased energy expenses when they settle. Prior to settlement the change in fair values of forward sale and purchase contracts are included in revenues.

Trading purchases and sales through electricity and gas options, futures and swaps, represent financial transactions with the net proceeds reported in revenues at fair value upon entering the contracts.

Recording of the net changes in fair value of open trading contracts is commonly referred to as mark-to-market accounting.

The Company marks to market all open contracts from trading activities in accordance with EITF 98-10 and includes the net mark-to-market (change in fair value) amount in revenues on a net discounted basis. The fair values of open short-term trading contracts are based on exchange prices and broker quotes. Open long-term trading contracts are marked to market based mainly on Company developed valuation models. The valuation models produce an estimated fair value for open long-term trading contracts. The short-term and long-term fair values are present valued and reduced by appropriate reserves for counterparty credit risks and liquidity risk. The models are derived from internally assessed market prices with the exception of the NYMEX gas curve, where we use daily settled prices. Bid/ask price curves are developed for inclusion in the model based on broker quotes and other available market data. The curves are within the range between the bid and ask price. The end of the month liquidity reserve is based on the difference in price between the price curve and the bid side of the bid ask if we have a long position and the ask side if we have a short position. This provides for a conservative valuation net of the reserves. The use of these models to fair value open trading contracts has inherent risks relating to the underlying assumptions employed by such models. Independent controls are in place to evaluate the reasonableness of the price curve models. Significant adverse or favorable effects on future results of operations and cash flows could occur if market risks, at the time of settlement, do not correlate with the Company developed price models.

The effect on the Consolidated Statements of Income of marking to market open electricity trading contracts in the Company's regulated jurisdictions is deferred as regulatory assets or liabilities since these transactions are included in cost of service on a settlement basis for ratemaking purposes. Unrealized mark-to-market gains and losses from trading activities whether deferred or recognized in revenues activities are part of Energy Trading and Derivative Contracts assets or liabilities as appropriate.

Derivatives and Hedges – AEP marks to market derivatives and hedges under SFAS 133 except when derivatives qualify as normal purchase and sales contracts. For those derivatives that qualify as normal purchases and sales, we record the contracts on a settlement basis, that is, we do not record any change in fair value of the open contract.

In order to mitigate market risks, management can elect to enter into derivative hedge transactions. Changes in the market value of cash flow hedges are deferred in other comprehensive income until the gain or loss is realized on the underlying hedged asset, liability or forecasted transactions. To qualify as a hedge, transactions must be designated as a hedge at inception and changes in their fair value must correlate highly with changes in value of the underlying asset, liability or forecasted transactions. This in effect reduces the Company's exposure to the effects of market risks.

See Note 13 – "Risk Management, Financial Instruments and Derivatives" for further discussion of the accounting for risk management transactions.

We also enter into fair value hedges of commodity contracts that we trade, primarily electricity and gas but generally do not elect to employ hedge accounting. We mark to market these open hedge contracts along with the open trading position being hedged. To the extent the hedge is effective, the fair value of the hedge and underlying asset or liability offset each other.

Levelization of Nuclear Refueling Outage Costs - In order to match costs with regulated revenues, incremental operation and maintenance costs associated with periodic nuclear refueling outages at I&M's Cook Plant are deferred and amortized over the period beginning with the commencement of an outage and ending with the beginning of the next outage.

Maintenance Costs – Maintenance costs are expensed as incurred except where SFAS 71 requires the recordation of a regulatory asset to match the expensing of maintenance costs with their recovery in cost based regulated revenues. See below for an explanation of costs deferred in connection with an extended outage at I&M's Cook Plant.

Amortization of Cook Plant Deferred Restart Costs - Pursuant to settlement agreements approved by the IURC and the MPSC to resolve all issues related to an extended outage of the Cook Plant, I&M deferred $200 million of incremental operation and maintenance costs during 1999. The deferred amount is being amortized to expense on a straight-line basis over five years from January 1, 1999 to December 31, 2003. I&M amortized $40 million in 2001, 2000 and 1999 leaving $80 million as an SFAS 71 regulatory asset at December 31, 2001 on the Consolidated Balance Sheets of AEP and I&M.

Other Income and Other Expenses – Other Income includes equity earnings of non-consolidated subsidiaries, gains on dispositions of property, interest and dividends, an allowance for equity funds used during construction (explained above) and various other non-operating and miscellaneous income. Other Expenses includes losses on dispositions of property, miscellaneous amortization, donations and various other non-operating and miscellaneous expenses.

Income Taxes - AEP 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 regulated revenues (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 to match the regulated revenues and tax expense.

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 the regulated plant investment.

Excise Taxes – AEP, as an agent for a state or local government, collects from customers certain excise taxes levied by the state or local government upon the customer. These taxes are not recorded as revenue or expense, but only as a pass-through billing to the customer to be remitted to the government entity. Excise tax collections and payments related to taxes imposed upon the customer are not presented in the income statement.

Debt and Preferred Stock – Gains and losses from the reacquisition of debt used to finance domestic regulated electric utility plant are generally deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment. If debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost based regulatory accounting under SFAS 71 are generally deferred and amortized over the term of the replacement debt commensurate with their recovery in rates. Gains and losses on the reacquisition of debt for operations not subject to SFAS 71 are reported as a component of net income.

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.

Where rates are regulated, redemption premiums paid to reacquire preferred stock of the domestic utility subsidiaries are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and amortized to retained earnings consistent with the timing of its inclusion in rates in accordance with SFAS 71.
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Goodwill and Intangible Assets – The amount of acquisition cost in excess of the fair value allocated to tangible and identifiable intangible assets obtained through an acquisition accounted for as a purchase combination is recorded as goodwill on AEP's consolidated balance sheet. Goodwill recognized in connection with purchase combinations acquired after June 30, 2001 was determined in accordance with SFAS 141 "Business Combinations." (see also Note 9, "Acquisitions and Dispositions"). For goodwill associated with purchase combinations before July 1, 2001, amortization is on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which is being amortized on a straight-line basis over 10 years. Accumulated amortization of goodwill was $199 million and $166 million at December 31, 2001 and 2000, respectively. In accordance with SFAS 142, "Goodwill and Other Intangible Assets," goodwill acquired after June 30, 2001 is not subject to amortization. The amortization of goodwill which predates July 1, 2001 ceased on December 31, 2001.

SFAS 142 requires that other intangible assets be separately identified and if they have finite lives they must be amortized over that life. Other intangible assets of $441 million net of accumulated amortization of $38 million at December 31, 2001 are included in other assets and represent retail and wholesale distribution licenses for CitiPower operating franchises which are currently being amortized on a straight-line basis over 20 and 40 years, respectively.

Also SFAS 142 provides that goodwill and other intangible assets with indefinite lives be tested for impairment annually and not be subjected to amortization. For AEP's goodwill recognized prior to July 1, 2001 and other intangible assets, these requirements will apply beginning January 1, 2002. For the year 2001, the amortization of goodwill and other intangibles reduced AEP's net income by $50 million. AEP is still evaluating the impact of adopting the impairment tests required by SFAS 142.

Nuclear Trust Funds – Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions have allowed us to collect through rates to fund future decommissioning and spent fuel disposal liabilities. By rules or orders, the state jurisdictional commissions (Indiana, Michigan and Texas) and the FERC established investment limitations and general risk management guidelines to protect their ratepayers' funds and to allow those funds to earn a reasonable return. In general, limitations include:

- Acceptable investments (rated investment grade or above)
- Maximum percentage invested in a specific type of investment
- Prohibition of investment in obligations of the applicable company or its affiliates.

Trust funds are maintained for each regulatory jurisdiction and managed by investment managers, who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested in order to optimize the after-tax earnings of the Trust, giving consideration to liquidity, risk, diversification, and other prudent investment objectives.

Nuclear decommissioning and spent nuclear fuel disposal trust funds are included in other assets. Securities held in trust funds for decommissioning nuclear facilities and for the disposal of spent nuclear fuel are included in Other Assets 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. In accordance with 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 spent nuclear fuel disposal trust funds in accordance with their treatment in rates.

Comprehensive Income - Comprehensive income is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive Income has two components, net income and other comprehensive income.

Components of Other Comprehensive Income – Other Comprehensive Income is included on the balance sheet in the equity section. The following table provides the components that comprise the balance sheet amount in Accumulated Other Comprehensive Income.

Components	2001	December 31, 2000	1999
		(millions)	
Foreign Currency Adjustments	$(113)	$ (99)	$ 20
Unrealized Losses On Securities	-	-	(20)
Unrealized Gain on Hedged Derivatives	(3)	-	-
Minimum Pension Liability	(10)	(4)	(4)
	$(126)	$(103)	$ (4)

Common Stock Options – AEP follows Accounting Principles Board Opinion 25 to account for stock options. No compensation expense is recognized at the date of grant or when exercised, because the exercise price of stock options awarded under the stock option plan equals the market price of the underlying stock on the date of grant.

EPS – Basic earnings per share is computed based upon the weighted average number of common shares outstanding during the years presented. Diluted earnings per share is based upon the weighted average number of common shares and stock options outstanding during the years presented. Basic and diluted EPS are the same in 2001, 2000 and 1999.

Reclassification - Certain prior year financial statement items have been reclassified to conform to current year presentation. Such reclassification had no impact on previously reported net income. Certain settled forward energy transactions of the trading operation were reclassified from a net to a gross basis of presentation in order to better reflect the scope and nature of the AEP System's energy sales and purchases. All financially net settled trading transactions, such as swaps, futures, and unexercised options, and all marked-to-market values on open trading contracts continue to be reported on a net basis, reflecting the financial nature of these transactions. As applicable, prior year amounts of realized physical purchases from settled purchase trading contracts were reclassified from revenues to purchased power expense to present the prior period on a comparable gross basis.

2. Extraordinary Items and Cumulative Effect:

Extraordinary Items – Extraordinary items were recorded for the discontinuance of regulatory accounting under SFAS 71 for the generation portion of the business in the Ohio, Virginia, West Virginia, Texas and Arkansas state jurisdictions. See Note 7, "Customer Choice and Industry Restructuring" for descriptions of the restructuring plans and related accounting effects. OPCo and CSPCo recognized an extraordinary loss for stranded Ohio Public Utility Excise Tax (commonly known as the Gross Receipts Tax – GRT) net of allowable Ohio coal credits during the quarter ended June 30, 2001. This loss resulted from regulatory decisions in connection with Ohio deregulation which stranded the recovery of the GRT. Effective with the liability affixing on May 1, 2001, CSPCo and OPCo recorded an extraordinary loss under SFAS 101. Both Ohio companies have appealed to the Ohio Supreme Court the PUCO order on Ohio restructuring that the Ohio companies believe failed to provide for recovery for the final year of the GRT. The Ohio Supreme Court decision is expected in 2002.

In October 2001 CPL reacquired $101 million of pollution control bonds in advance of their maturity. Since these pollution control bonds were used to finance generation assets, a loss of $2 million after tax was recorded.

The following table shows the components of the extraordinary items reported on the consolidated statements of income:

	Year Ended December 31, 2001	2000	1999
	(in millions)		
Extraordinary Items:			
Discontinuance of Regulatory Accounting for Generation:			
Ohio Jurisdiction (Net of Tax of $20 million in 2001 and $35 Million in 2000)	$(48)	$(44)	$ -
Virginia and West Virginia Jurisdictions (Inclusive of Tax Benefit of $8 Million)	-	9	-
Texas and Arkansas Jurisdictions (Net of Tax of $5 Million)	-	-	(8)
Loss on Reacquired Debt (Net of Tax of $1 Million in 2001 and $3 Million in 1999)	(2)	-	(6)
Extraordinary Items	$(50)	$(35)	$(14)

Cumulative Effect of Accounting Change - The FASB's Derivative Implementation Group (DIG) issued accounting guidance under SFAS 133 for certain derivative fuel supply contracts with volumetric optionality and derivative electricity capacity contracts. This guidance, effective in the third quarter of 2001, concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when electricity capacity contracts can qualify as a normal purchase or sale.

Predominantly all of AEP's fuel supply contracts for coal and gas and contracts for electricity capacity, which are recorded on a settlement basis, do not meet the criteria of a financial derivative instrument. Therefore, AEP's contracts are generally exempt from the DIG guidance described above. Beginning July 1, 2001, the effective date of the DIG guidance, certain of AEP's fuel supply contracts with volumetric optionality that qualify as financial derivative instruments are marked to market with any gain or loss recognized in the income statement. The effect of initially adopting the DIG guidance at July 1, 2001, a favorable earnings mark-to-market effect of $18 million, net of tax of $2 million, is reported as a cumulative effect of an accounting change on the income statement.

3. Merger:

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. Under the terms of the merger agreement, approximately 127.9 million shares of AEP Common Stock were issued in exchange for all the outstanding shares of CSW Common Stock based upon an exchange ratio of 0.6 share of AEP Common Stock for each share of CSW Common Stock. Following the exchange, former shareholders of AEP owned approximately 61.4 percent of the corporation, while former CSW shareholders owned approximately 38.6 percent of the corporation.

The merger was accounted for as a pooling of interests. Accordingly, AEP's consolidated financial statements give retroactive effect to the merger, with all periods presented as if AEP and CSW had always been combined. Certain reclassifications have been made to conform the historical financial statement presentation of AEP and CSW.

The following table sets forth revenues, extraordinary items and net income previously reported by AEP and CSW and the combined amounts shown in the accompanying financial statements for 1999:

	Year Ended December 31, 1999
	(in millions)
Revenues:	
AEP	$19,229
CSW	5,516
AEP After Pooling	$24,745
Extraordinary Items:	
AEP	$ -
CSW	(14)
AEP After Pooling	$(14)
Net Income:	
AEP	$520
CSW	455
Conforming Adjustment	(3)
AEP After Pooling	$972

The combined financial statements include an adjustment to conform CSW's accounting for vacation pay accruals with AEP's accounting. The effect of the conforming adjustment was to reduce net assets by $16 million at December 31, 1999 and reduce net income by $3 million for the year ended December 31, 1999.

In connection with the merger, $21 million ($14 million after tax) and $203 million ($180 million after tax) of non-recoverable merger costs were expensed in 2001 and 2000. Such cost included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable change in control payments. Merger transaction and transition costs of $51 million recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements through December 31, 2001. The deferred merger costs are being amortized over five to eight year recovery periods, depending on the specific terms of the settlement agreements, with the amortization ($8 million and $4 million for the years 2001 and 2000) included in depreciation and amortization expense. Merger transition costs are expected to continue to be incurred for several years after the merger and will be expensed or deferred for amortization as appropriate. As hereinafter summarized, the state settlement agreements provide for, among other things, a sharing of net merger savings with certain regulated customers over periods of up to eight years through rate reductions which began in the third quarter of 2000.

Summary of key provisions of Merger Rate Agreements:

State/Company	Ratemaking Provisions
Texas – CPL, SWEPCo WTU	$221 million rate reduction over 6 years. No base rate increases for 3 years post merger.
Indiana – I&M	$67 million rate reduction over 8 years. Extension of base rate freeze until January 1, 2005. Requires additional annual deposits of $6 million to the nuclear decommissioning trust fund for the years 2001 through 2003.
Michigan – I&M	Customer billing credits of approximately $14 million over 8 years. Extension of base rate freeze until January 1, 2005.
Kentucky – KPCo	Rate reductions of approximately $28 million over 8 years. No base rate increases for 3 years post merger.
Oklahoma – PSO	Rate reductions of approximately $28 million over 5 years. No base rate increase before January 1, 2003.
Arkansas – SWEPCo	Rate reductions of $6 million over 5 years.
Louisiana – SWEPCo	Rate reductions of $18 million over 8 years. Base rate cap until June 2005.

If actual merger savings are significantly less than the merger savings rate reductions required by the merger settlement agreements in the eight-year period following consummation of the merger, future results of operations, cash flows and possibly financial condition could be adversely affected.

The current annual dividend rate per share of AEP common stock is $2.40. The dividends per share reported on the statements of income for 2000 and 1999 represent pro forma amounts and are based on AEP's historical annual dividend rate of $2.40 per share. If the dividends per share reported for prior periods were based on the sum of the historical dividends declared by AEP and CSW, the annual dividend rate would be $2.60 per combined share for the year ended December 31, 1999.

See Note 8, "Commitments and Contingencies" for information on a recent court decision concerning the merger.

4. Nuclear Plant Restart:

I&M completed the restart of both units of the Cook Plant in 2000. Cook Plant is a 2,110 MW two-unit plant owned and operated by I&M under licenses granted by the NRC. I&M 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.

Settlement agreements in the Indiana and Michigan retail jurisdictions that address recovery of Cook Plant related outage costs were approved in 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 related issues during the extended outage of the Cook Plant. The MPSC approved a settlement agreement for two open Michigan power supply cost recovery reconciliation cases that resolved all issues related to the Cook Plant extended outage. The settlement agreements allowed:

- deferral of $200 million of non-fuel restart-related nuclear operation and maintenance expense for amortization over five years ending December 31, 2003,
- deferral of certain unrecovered fuel and power supply costs for amortization over five years ending December 31, 2003,
- a freeze in base rates through December 31, 2003 and a fixed fuel recovery charge

through March 1, 2004 in the Indiana jurisdiction, and

- a freeze in base rates and fixed power supply costs recovery factors until January 1, 2004 for the Michigan jurisdiction.

The amounts of restart costs charged to other operation and maintenance expenses were as follows:

	Year Ended December 31,		
	2001	2000	1999
		(in millions)	
Costs Incurred	$ 1	$297	$ 289
Deferred Pursuant to Settlement Agreements	-	-	(200)
Amortization of Deferrals	40	40	40
Charged to O&M Expense	$41	$337	$ 129

At December 31, 2001 and 2000, deferred restart costs of $80 million and $120 million, respectively, remained as regulatory assets to be amortized through 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of $38 million in 2001 and 2000 and $37 million in 1999 were amortized. At December 31, 2001 and 2000, fuel-related revenues of $75 million and $113 million, respectively, were included in regulatory assets and will be amortized through December 31, 2003 for both jurisdictions.

The amortization of restart costs and fuel-related revenues deferred under Indiana and Michigan retail jurisdictional settlement agreements will adversely affect results of operations through December 31, 2003 when the amortization period ends. The annual amortization of restart cost and fuel-related revenue deferrals is $78 million.

5. Rate Matters:

Texas Jurisdictional Fuel Filings – AEP's Texas electric operating companies experienced significant natural gas price increases in the second half of 2000 and early 2001 which resulted in under-recovery of fuel costs and the need to seek increases in fuel rates and surcharges to recover these under-recoveries. During 2001 gas price declines and PUCT-approved fuel rate and fuel surcharge increases resulted in lower unrecovered fuel balances for SWEPCo and WTU and an overrecovered balance for CPL at the end of 2001.

Fuel recovery for Texas utilities is a multi-step procedure. When fuel costs change, utilities file with the PUCT for authority to adjust fuel factors. If a utility's prior fuel factors result in an over- or under-recovery of fuel, the utility will also request a surcharge factor to refund or collect that amount. While fuel factors are intended to recover all fuel-related costs, final settlement of these accounts are subject to reconciliation and approval by the PUCT.

Fuel reconciliation proceedings determine whether fuel costs incurred and collected during the reconciliation period were reasonable and necessary. All fuel costs incurred since the prior reconciliation date are subject to PUCT review and approval. If material amounts are determined to be unreasonable and ordered to be refunded to customers, results of operations and cash flows would be negatively impacted.

According to Texas Restructuring Legislation, fuel cost in the Texas jurisdiction after 2001 will no longer be subject to PUCT review and reconciliation. During 2002 CPL and WTU will file final fuel reconciliations with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. The ultimate recovery of deferred fuel balances at December 31, 2001 will be decided as part of their 2004 true-up proceedings. If the final under-recovered fuel balances or any amounts incurred but not yet reconciled are disallowed, it would have a negative impact on results of operations and cash flows.

In October 2001 the PUCT delayed the start of customer choice in the SPP area of Texas. All of SWEPCo's Texas service territory and a small portion of WTU's service territory are in the SPP. SWEPCo's fuel cost recovery procedures will continue until competition begins. SWEPCo will continue to set fuel factors and determine final fuel costs in fuel reconciliation proceedings during the SPP delay period. The PUCT has ruled that WTU fuel factors in the SPP area will be based upon the price to beat fuel factors offered by the WTU retail electric provider in the ERCOT portion of WTU's service territory. The PUCT has initiated a proceeding to determine the most appropriate method to reconcile fuel costs in WTU's SPP area.

The following table lists the status of Texas jurisdictional reconciliation, fuel cost subject to reconciliation and under(over)-recovered fuel balances:

Company	Reconciliation completed through	Fuel cost subject to reconciliation at December 31, 2001
CPL	June 30, 1998	$1.6 billion
SWEPCo	December 31, 1999	314 million
WTU	June 30, 2000	303 million

Company	Under (Over) -recovered fuel balances at December 31, 2001
CPL	$(58) million
SWEPCo	7 million
WTU	34 million

During 2001 CPL, SWEPCo and WTU requested and received approval to increase their fuel rates. In orders issued in 2001 the PUCT delayed consideration of fuel surcharges for CPL and WTU to recover their underrecovered fuel until the 2004 true-up proceedings. CPL's net underrecovered position was eliminated between the order date and year end 2001 as gas prices declined. For SWEPCo the PUCT deferred $6.8 million of Texas jurisdictional unrecovered fuel for consideration in a future proceeding.

Under Texas restructuring, newly organized retail electric providers will make sales to consumers beginning January 1, 2002. These sales will be at fixed rates during a transition period from 2002 through 2006. However, the fuel cost component of a retail electric providers' fixed rates will be subject to prospective adjustment twice a year based upon changes in a natural gas price index. As part of the preparation for customer choice, CPL, SWEPCo and WTU filed their proposed fuel factors to be implemented as part of the fixed rates effective January 1, 2002. Fuel factors approved for CPL's and WTU's retail electric providers were effective January 1, 2002. Due to the SPP area competition delay, SWEPCo's proceeding was postponed.

WTU Fuel Filings - In December 2000 WTU filed with the PUCT an application to reconcile fuel costs. During the reconciliation period of July 1, 1997 through June 30, 2000, WTU incurred $348 million of Texas jurisdiction eligible fuel and fuel-related expenses. In February 2002 the PUCT approved WTU's fuel cost for the reconciliation period except for a disallowance of less than $50,000.

Texas Transmission Rates – On June 28, 2001, the Supreme Court of Texas ruled that the transmission pricing mechanism created by the PUCT in 1996 was invalid. The court upheld an appeal filed by unaffiliated Texas utilities that the PUCT exceeded its statutory authority to set such rates for the period January 1, 1997 through August 31, 1999. Effective September 1, 1999, the legislature granted this authority to the PUCT. CPL and WTU were not parties to the case. However, the companies' transmission sales and purchases were priced using the invalid rates. It is unclear what action the PUCT will take to respond to the court's ruling. If the PUCT changes rates retroactively, the result could have a material impact on results of operations and cash flows for CPL and WTU.

FERC Wholesale Fuel Complaints – In May 2000 certain WTU wholesale customers filed a complaint with FERC alleging that WTU had overcharged them through the fuel adjustment clause for certain purchased power costs related to 1999 unplanned outages at WTU's Oklaunion generation station. In November 2001, certain WTU wholesale customers filed an additional complaint at FERC asserting that since 1997 WTU had billed wholesale customers for not only the 1999 Oklaunion outage costs, but also certain additional costs that are not permissible under the fuel adjustment clause.

In December 2001 FERC issued an order requiring WTU to refund, with interest, amounts associated with the May 2000 complaint that were previously billed to wholesale customers. The effects of this order were recorded in 2001 and management believes that as of December 31, 2001, it has fully provided for that over billing. In response to the November 2001 complaint, management is working to determine amounts of additional costs inappropriately billed to wholesale customers, which could result in refunds, with interest. At this time, management is unable to predict the negative impact this complaint will have on future results of operations, cash flow and financial condition.

FERC Transmission Rates – In November 2001 FERC issued an order requiring CPL, PSO, SWEPCo and WTU to submit revised open access transmission tariffs, and calculate and issue refunds for overcharges from January 1, 1997. The order resulted from a remand by an appeals court of a tariff compliance filing order issued in November 1998 that had been appealed by certain customers. The companies recorded refund provisions netting to $2.6 million including interest in 2001 for this order.

West Virginia - On June 2, 2000, the WVPSC approved a Joint Stipulation between APCo and other parties related to base rates and ENEC recoveries. The Joint Stipulation allows for recovery of regulatory assets including any generation-related regulatory assets through the following provisions:

- Frozen transition rates and a wires charge of 0.5 mills per KWH.
- The retention, as a regulatory liability, on the books of a net cumulative deferred ENEC over-recovery balance of $66 million to be used to offset the cost of deregulation when generation is deregulated in WV.
- The retention of net merger savings prior to December 31, 2004 resulting from the merger of AEP and CSW.
- A 0.5 mills per KWH wires charge for departing customers provided for in the WV Restructuring Plan (see Note 7 "Customer Choice and Industry Restructuring" for discussion of the WV Restructuring Plan)

Management expects that the approved Joint Stipulation, plus the provisions of pending restructuring legislation will, if the legislation becomes effective, provide for the recovery of existing regulatory assets, other stranded costs and the cost of deregulation in WV.

6. Effects of Regulation:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. It is expected that regulatory assets will be recovered in future periods through the rate-making process and regulatory liabilities will reduce future cost recoveries. Among other things, application of SFAS 71 requires that AEP's regulated rates be cost-based and the recovery of regulatory assets be probable. Management has reviewed all the evidence currently available and concluded that the requirements to apply SFAS 71 continue to be met for all of the Company's electric operations in Indiana, Kentucky, Louisiana, Michigan, Oklahoma and Tennessee.

When the generation portion of the Company's business in Arkansas, Ohio, Texas, Virginia and WV no longer met the requirements to apply SFAS 71, net regulatory assets were written off for that portion of the business unless they were determined to be recoverable as a stranded cost through regulated distribution rates or wire charges in accordance with SFAS 101 and EITF 97-4. In the Ohio and WV jurisdictions generation-related regulatory assets that are recoverable through transition rates have been transferred to the distribution portion of the business and are being amortized as they are recovered through charges to regulated distribution customers. As discussed in Note 7, "Customer Choice and Industry Restructuring" the Virginia SCC ordered the generation-related regulatory assets in the Virginia jurisdiction to remain with the generation portion of the business. Generation-related regulatory assets in the Virginia jurisdiction are being amortized concurrent with their recovery through capped rates. In the Texas jurisdiction generation-related regulatory assets that have been tentatively approved for recovery through securitization have been classified as "regulatory assets designated for securitization." (See Note 7 "Customer Choice and Industry Restructuring" for further details.)

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

	December 31, 2001	December 31, 2000
	(millions)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$ 814	$ 914
Transition - Regulatory Assets	847	963
Regulatory Assets Designated for Securitization	959	953
Deferred Fuel Costs	139	407
Unamortized Loss on Reacquired Debt	99	113
Cook Plant Restart Costs	80	120
DOE Decontamination and Decommissioning Assessment	31	35
Other	193	193
Total Regulatory Assets	$3,162	$3,698

	December 31, 2001	December 31, 2000
	(millions)	
Regulatory Liabilities:		
Deferred Investment Tax Credits	$491	$528
Other	393	208
Total Regulatory Liabilities	$884	$736

At December 31, 2001 $1,911 million of regulatory assets are not earning a return.

- $636 million of the total $814 million for amounts due from customers for future income taxes are not earning a return. These balances are reversed as the associated deferred tax timing differences are reversed, and have no specific amortization period.
- Transition regulatory assets of $847 million are not earning a return and had the following recovery periods.
  - $495 million six years
  - $224 million seven years
  - $128 million ten years
- Deferred fuel costs of $139 million includes $83 million that was not earning a return and had the following recovery periods:
  - $2 million two months
  - $6 million one year
  - $75 million two years
- Cook plant restart costs of $80 million does not earn a return and has a recovery period of two years.
- Unamortized loss on reacquired debt includes $48 million not earning a return and ranges from one to thirty-seven years recovery period.
- The balance of $217 million not earning a return is of varying natures and recovery periods.

7. Customer Choice and Industry Restructuring:

Prior to 2001 customer choice/industry restructuring legislation was passed in Ohio, Texas, Virginia and Michigan allowing retail customers to select alternative generation suppliers. Customer choice began on January 1, 2001 in Ohio and on January 1, 2002 in Michigan, Virginia and in the ERCOT area of Texas. AEP's subsidiaries operate in both the ERCOT and SPP areas of Texas.

Legislation enacted in Oklahoma, Arkansas and WV to allow retail customers to choose their electricity supplier is not yet effective. In 2001 Oklahoma delayed implementation of customer choice indefinitely. Arkansas delayed the start of customer choice until as late as October 2005. The Arkansas Commission has recommended further delays of the start date or repeal of the restructuring legislation. Before West Virginia's choice plan can be effective, tax legislation must be passed to continue consistent funding for state and local government. No further legislation has been passed related to restructuring in Arkansas or West Virginia.

In general, state restructuring legislation provides for a transition from cost-based rate regulated bundled electric service to unbundled cost-based rates for transmission and distribution service and market pricing for the supply of electricity with customer choice of supplier.

Ohio Restructuring

Customer choice of electricity supplier and restructuring began on January 1, 2001, under the Ohio Act. During 2001 alternative suppliers registered and were approved by the PUCO as required by the Ohio Act. At January 1, 2002, virtually all customers continue to receive supply service from CSPCo and OPCo with a legislatively required residential generation rate reduction of 5%. All customers continue to be served by CSPCo and OPCo for transmission and distribution services.

The Ohio Act provides for a five-year transition period to move from cost based rates to market pricing for electric generation supply services. It granted the PUCO broad oversight responsibility for promulgation of rules for competitive retail electric generation service, approval of a transition plan for each electric utility company and addressed certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

The Ohio Act made several changes in the taxation of electric companies. Effective January 1, 2001 the assessment percentage for property taxes on all electric company property other than transmission and distribution was lowered from 100% to 25%. The assessment percentage applicable to transmission and distribution property remains at 88%. Also, electric companies were exempted from the excise tax based on receipts. To make up for these tax reductions electric distribution companies became subject to a new KWH based excise tax. Since electric companies no longer paid the gross receipts tax, they became liable, as of January 1, 2002 for the corporation franchise tax and municipal income taxes.

In preparation for the January 1, 2001 start of the transition period, CSPCo and OPCo filed a transition plan in December 1999. After negotiations with interested parties including the PUCO staff, the PUCO approved a stipulation agreement for CSPCo's and OPCo's transition plans. The approved plans included, among other things, recovery of generation-related regulatory assets over seven years for OPCo and over eight years for CSPCo through frozen transition rates for the first five years of the recovery period and through a wires charge for the remaining years. At December 31, 2000, the amount of regulatory assets to be amortized as recovered was $518 million for OPCo and $248 million for CSPCo.

The stipulation agreement required the PUCO to consider implementation of a gross receipts tax credit rider as the parties could not reach an agreement.

As of May 1, 2001, electric distribution companies became subject to an excise tax based on KWH sold to Ohio customers. The last tax year for which Ohio electric utilities will pay the excise tax based on gross receipts is May 1, 2001 through April 30, 2002. As required by law, the gross receipts tax is paid in advance of the tax year for which the utility exercises its privilege to conduct business. CSPCo and OPCo treat the tax payment as a prepaid expense and amortized it to expense during the tax year.

Following a hearing on the gross receipts tax issue, the PUCO determined that there was no duplicate tax overlap period. The PUCO ordered the gross receipts tax credit rider to be effective May 1, 2001 instead of May 1, 2002 as proposed by the companies. This order reduced CSPCo's and OPCo's revenues by approximately $90 million. CSPCo's and OPCo's request for rehearing of the gross receipts tax issue was also denied by the PUCO. A decision on an appeal of this issue to the Ohio Supreme Court is pending.

As described in Note 2, "Extraordinary Items and Cumulative Effect" the PUCO's denial of the request for recovery of the final year's gross receipts tax and the tax liability affixing on May 1, 2001 stranded the prepaid asset. As a result, an extraordinary loss was recorded in 2001.

One of the intervenors at the hearings for approval of the settlement agreement (whose request for rehearing was denied by the PUCO) filed with the Ohio Supreme Court for review of the settlement agreement. During 2001 that intervenor withdrew from competing in Ohio. The Court dismissed the intervenor's appeal.

CSPCo's and OPCo's fuel costs were no longer subject to PUCO fuel clause recovery proceedings beginning January 1, 2001. The elimination of fuel clause recoveries in Ohio subjects AEP, CSPCo and OPCo to risk of fuel market price variations and could adversely affect their results of operations and cash flows.

Virginia Restructuring

In Virginia, choice of electricity supplier for retail customers began on January 1, 2002 under its restructuring law. A finding by the Virginia SCC that an effective competitive market exists would be required to end the transition period.

The restructuring law provides an opportunity for recovery of just and reasonable net stranded generation costs. The mechanisms in the Virginia law for net stranded cost recovery are: a capping of rates until as late as July 1, 2007, and the application of a wires charge upon customers who depart the incumbent utility in favor of an alternative supplier prior to the termination of the rate cap. Capped rates are the rates in effect at July 1, 1999 if no rate change request was made by the utility. APCo did not request new rates; therefore, its current rates are its capped rates. Virginia's restructuring law does not permit the Virginia SCC to change generation rates during the transition period except for changes in fuel costs, changes in state gross receipts taxes, or to address financial distress of the utility.

The Virginia restructuring law also requires filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. On January 3, 2001, APCo filed its corporate separation plan and rate unbundling plan with the Virginia SCC. The Virginia SCC approved settlement agreements that resolved most issues except the assignment of generation–related regulatory assets among functionally separated generation, transmission and distribution organizations. The Virginia SCC determined that generation–related regulatory assets and related amortization expense should be assigned to APCo's generation function. Presently, capped rates are sufficient to recover generation–related regulatory assets. Therefore, management determined that recovery of APCo's generation–related regulatory assets remains probable. APCo will not collect a wires charge in 2002 per the settlement agreements. The settlement agreements and related Virginia SCC order addressed functional separation leaving decisions related to corporate separation for later consideration. The Virginia SCC order approving the settlement agreements requires several compliance filings, including a fuel/replacement power cost report during an extended outage of an affiliate's nuclear plant. Management is unable to predict the outcome of the Virginia SCC's review of APCo's compliance filings.

Texas Restructuring

On January 1, 2002, customer choice of electricity supplier began in the ERCOT area of Texas. Customer choice has been delayed in other areas of Texas including the SPP area. All of SWEPCo's Texas service territory and a small portion of WTU's service territory are located in the SPP. CPL operates entirely in the ERCOT area of Texas.

Texas restructuring legislation, among other things:

- provides for the recovery of regulatory assets and other stranded costs through securitization and non-bypassable wires charges;
- requires reductions in NOx and sulfur dioxide emissions;
- freezes rates until January 1, 2002;
- provides for an earnings test for each of the three years of the rate freeze period (1999 through 2001) which will reduce stranded cost recoveries or if there is no stranded cost provides for a refund or their use to fund certain capital expenditures;
- requires each utility to structurally unbundle into a retail electric provider, a power generation company and a transmission and distribution utility;
- provides for certain limits for ownership and control of generating capacity by companies;
- provides for elimination of the fuel clause reconciliation process beginning January 1, 2002; and
- provides for a 2004 true-up proceeding to determine recovery of stranded costs including final fuel recovery balances, net regulatory assets, certain environmental costs, accumulated excess earnings and other issues.

Under the Texas Legislation, delivery of electricity continues to be the responsibility of the local electric transmission and distribution utility company at regulated prices. Each electric utility was required to submit a plan to structurally unbundle its business activities into a retail electric provider, a power generation company, and a transmission and distribution utility. In 2000 CPL, SWEPCo and WTU filed and the PUCT approved business separation plans. The business separation plans provided for CPL and WTU to establish separate companies and divide their integrated utility operations and assets into a power generation company, a transmission and distribution utility and a retail electric provider. In February 2002 the PUCT approved amendments to SWEPCo's plan. The amended plan separates SWEPCo's Texas jurisdictional transmission and distribution assets and operations into two new regulated transmission and distribution subsidiaries. In addition, a retail electric provider was established by SWEPCo to provide retail electric service to SWEPCo's Texas jurisdictional customers. Until competition commences in the SPP, SWEPCo's assets will not be separated and the SWEPCo retail electric provider will not commence operation.

Due to the SPP area delay in the start of competition, only CPL's and WTU's retail electric providers commenced operations on January 1, 2002. Operations for CPL, SWEPCo and WTU have been functionally separated.

Under the Texas Legislation, electric utilities are allowed to recover stranded generation costs including generation-related regulatory assets. The stranded costs can be refinanced through securitization (a financing structure designed to provide lower financing costs than are available through conventional financings).

In 1999 CPL filed with the PUCT to securitize $1.27 billion of its retail generation-related regulatory assets and $47 million in other qualified restructuring costs. The PUCT authorized the issuance of up to $797 million of securitization bonds ($949 million of generation-related regulatory assets and $33 million of qualified refinancing costs offset by $185 million of customer benefits for accumulated deferred income taxes). Four parties appealed to the Supreme Court of Texas which upheld the PUCT's securitization order. CPL issued its securitization bonds in February 2002.

CPL included regulatory assets not approved for securitization in its request for recovery of $1.1 billion of stranded costs. The $1.1 billion request included $800 million of STP costs included in property, plant and equipment-electric on the Consolidated Balance Sheets. These STP costs had previously been identified as excess cost over market (ECOM) by the PUCT for regulatory purposes. They are earning a lower return and being amortized on an accelerated basis for rate-making purposes.

After hearings on the issue of stranded costs, the PUCT ruled in October 2001 that its current estimate of CPL's stranded costs was negative $615 million. CPL disagrees with the ruling. The ruling indicated that CPL's costs were below market after securitization of regulatory assets. Management believes CPL has a positive stranded cost exclusive of securitized regulatory assets. The final amount of CPL's stranded costs including regulatory assets and ECOM will be established by the PUCT in the 2004 true-up proceeding. If CPL's total stranded costs determined in the 2004 true-up are less than the amount of securitized regulatory assets, the PUCT can implement an offsetting credit to transmission and distribution rates.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of regulatory costs authorized by the PUCT to be securitized. However, the PUCT also ruled that excess earnings for the period 1999-2001 should be refunded through distribution rates to the extent of any over-mitigation of stranded costs represented by negative ECOM. In 2001 the PUCT issued an order requiring CPL to reduce distribution rates by $54.8 million plus accrued interest over a five-year period beginning January 1, 2002 in order to return estimated excess earnings for 1999, 2000 and 2001. The Texas Legislation intended that excess earnings reduce stranded costs. Final stranded cost amounts and the treatment of excess earnings will be determined in the 2004 true-up proceeding. Currently the PUCT estimates that CPL will have no stranded costs and has ordered the rate reduction to return excess earnings. Since CPL expensed excess earnings amounts in 1999, 2000 and 2001, the order has no additional effect on reported net income but will reduce cash flows for the five year refund period. The amount to be refunded is recorded as a regulatory liability.

Management believes that CPL will have stranded costs in 2004, and that the current treatment of excess earnings will be amended at that time. CPL has appealed the PUCT's estimate of stranded costs and refund of excess earnings to the Travis County District Court.

Unaffiliated parties also appealed the PUCT's refund order contending the entire $615 million of negative stranded costs should be refunded presently. Management is unable to predict the outcome of this litigation. An unfavorable ruling would have a negative impact on results of operations, cash flows and possibly financial condition.

The Texas Legislation allows for several alternative methods to be used to value stranded costs in the final 2004 true-up proceeding including the sale or exchange of generation assets, the issuance of power generation company stock to the public or the use of an ECOM model. To the extent that the final 2004 true-up proceeding determines that CPL should recover additional stranded costs, the additional amount recoverable can also be securitized.

The Texas Legislation provides for an earnings test each year of the 1999 through 2001 rate freeze period. For CPL, any earnings in excess of the most recently approved cost of capital in its last rate case must be applied to reduce stranded costs. Companies without stranded costs, including SWEPCo and WTU, must pay any excess earnings to customers, invest them in improvements to transmission or distribution facilities or invest them to improve air quality at generating facilities. The Texas Legislation requires PUCT approval of the annual earnings test calculation.

The PUCT issued a final order for the 1999 earnings test in February 2001 and adjustments to the accrued 1999 and 2000 excess earnings were recorded in results of operations in the fourth quarter of 2000. After adjustments the 1999 excess earnings for CPL and WTU were $24 million and $1 million, respectively. SWEPCo had no excess earnings in 1999. The PUCT issued a final order in September 2001 for the 2000 excess earnings. CPL's, SWEPCo's and WTU's excess 2000 earnings were $23 million, $1 million and $17 million, respectively. An estimate of 2001 excess earnings of $8 million for CPL, $2 million for SWEPCo and none for WTU has been recorded and will be adjusted, if necessary, in 2002 when the PUCT issues its final order regarding 2001 excess earnings.

Due to the companies' disagreement with the PUCT, its staff and the Office of Public Utility Counsel related to the proper determination of 2000 excess earnings, the companies filed in district court in October 2001 seeking judicial review of the PUCT's determination of excess earnings. A decision from the court is not expected until later in 2002.

Beginning January 1, 2002, fuel costs will not be subject to PUCT fuel reconciliation proceedings for CPL and WTU's ERCOT customers. Consequently, CPL and WTU will file a final fuel reconciliation with the PUCT to reconcile their fuel costs through the period ending December 31, 2001. Due to the delay of competition for the SPP area, SWEPCo, which operates in the SPP area, continues to record and request recovery of fuel costs under the Texas fuel reconciliation proceeding. For WTU's SPP area customers, the PUCT will determine a method to reconcile their fuel costs beginning in 2002 (see Note 5 "Rate Matters"). Final unrecovered deferred fuel balances at December 31, 2001 will be included in each company's 2004 true-up proceeding. If the final fuel balances or any amount incurred but not yet reconciled are not recovered, they could have a negative impact on results of operations. The elimination of the fuel clause recoveries in 2002 in the ERCOT area of Texas will subject AEP and the retail electric providers of CPL and WTU to greater risks of fuel market price increases and could adversely affect future results of operations beginning in 2002.

The affiliated retail electric providers of CPL, SWEPCo and WTU are required by the Texas Legislation to offer residential and small commercial customers (with a peak usage of less than 1000 KW) a price-to-beat rate until January 1, 2007. In December 2001 the PUCT approved price-to-beat rates for CPL's and WTU's retail electric providers. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas restructuring legislation provides for the price to beat to be adjusted up to two times annually to reflect changes in fuel and purchased energy costs using a natural gas price index.

Due to the delay in the start of competition in the SPP areas of Texas, several issues are pending before the PUCT. These issues impact

SWEPCo's and WTU's Texas SPP operations. WTU's Texas SPP operations are estimated to be less than 5% of WTU's total operations.

West Virginia Restructuring

In 2000 the WVPSC issued an order approving an electricity restructuring plan which the WV Legislature approved by joint resolution. The joint resolution provides that the WVPSC cannot implement the plan until the legislature makes tax law changes necessary to preserve the revenues of state and local governments. Since the WV Legislature has not passed the required tax law changes, the restructuring plan has not become effective. AEP subsidiaries, APCo and WPCo, provide electric service in WV.

The WV restructuring plan provides for:

- deregulation of generation assets
- separation of the generation, transmission and distribution businesses
- a transition period with capped and fixed rates for up to 13 years
- establishment of a rate stabilization deferred liability balance of $81 million ($76 million by APCo and $5 million by WPCo) by the end of year ten of the transition period.

APCo's Joint Stipulation, discussed in Note 5 "Rate Matters" and approved by the WVPSC in 2000 in connection with a base rate filing, provides additional mechanisms to recover transition generation-related regulatory assets.

In order for customer choice to become effective in WV, the WV Legislature must enact tax legislation. Management is unable to predict the timing of the passage of such legislation.

Arkansas Restructuring

In 1999 Arkansas enacted legislation to restructure its electric utility industry. Major provisions of the legislation as amended are:

- retail competition delayed until as late as October 2005;
- transmission facilities must be operated by an ISO if owned by a company which also owns generating facilities;
- rates will be frozen for one to three years;
- market power issues will be addressed by the Arkansas Commission; and
- an annual progress report to the Arkansas General Assembly on the development of competition in electric markets and its impact on retail customers is required.

Based on recommendations in the annual progress report filed by the Arkansas Commission, the Arkansas General Assembly passed and the Governor signed legislation in 2001 changing the start date of electric retail competition to October 1, 2003, and providing the Arkansas Commission with authority to delay that date for up to an additional two years.

The Arkansas Commission in December 2001 recommended further delays of the start date or repeal of the restructuring legislation.

Discontinuance of the Application of SFAS 71 Regulatory Accounting in Arkansas, Ohio, Texas, Virginia and West Virginia

The enactment of restructuring legislation and the ability to determine transition rates, wires charges and any resultant gain or loss under restructuring legislation in Arkansas, Ohio, Texas, Virginia and West Virginia enabled AEP and certain subsidiaries to discontinue regulatory accounting under SFAS 71 for the generation portion of their business in those states. Under the provisions of SFAS 71, regulatory assets and regulatory liabilities are recorded to reflect the economic effects of regulation by matching expenses with related regulated revenues.

The discontinuance of the application of SFAS 71 in Arkansas, Ohio, Texas, Virginia and West Virginia in accordance with the provisions of SFAS 101 and EITF Issue 97-4 resulted in recognition of extraordinary gains or losses in 2000 and 1999. The discontinuance of SFAS 71 can require the write-off of regulatory assets and liabilities related to the deregulated operations, unless their recovery is provided through cost-based regulated rates to be collected in a portion of operations which continues to be rate regulated. Additionally, a company must determine if any plant assets are impaired when they discontinue SFAS 71 accounting. At the time the companies discontinued SFAS 71, the analysis showed that there was no accounting impairment of generation assets.

Prior to 1999, all of the domestic electric utility subsidiaries' financial statements reflected the economic effects of regulation under the requirements of SFAS 71. As a result of deregulation of generation, the application of SFAS 71 for the generation portion of the business in Arkansas, Ohio, Texas, Virginia and West Virginia was discontinued. Remaining generation-related regulatory assets will be amortized as they are recovered under terms of transition plans. Management believes that substantially all generation-related regulatory assets and stranded costs will be recovered under terms of the transition plans. If future events including the 2004 true-up proceeding in Texas were to make their recovery no longer probable, the Company would write-off the portion of such regulatory assets and stranded costs deemed unrecoverable as a non-cash extraordinary charge to earnings. If any write-off of regulatory assets or stranded costs occurred, it could have a material adverse effect on future results of operations, cash flows and possibly financial condition.

Michigan Restructuring

On June 5, 2000, the Michigan Legislation became law. Its major provisions, which were effective immediately, applied only to electric utilities with one million or more retail customers. I&M, AEP's electric operating subsidiary doing business in Michigan, has less than one million customers in Michigan. Consequently, I&M was not immediately required to comply with the Michigan Legislation.

The Michigan Legislation gives the MPSC broad power to issue orders to implement retail customer choice of electric supplier no later than January 1, 2002 including recovery of regulatory assets and stranded costs. In compliance with MPSC orders, on June 5, 2001, I&M filed its proposed unbundled rates, open access tariffs and terms of service. On October 11, 2001, the MPSC approved a settlement agreement which generally approved I&M's June 5, 2001 filing except for agreed upon modifications. In accordance with the settlement agreement, I&M agreed that recovery of implementation costs and regulatory assets would be determined in future proceedings. The settlement agreement did not modify the procedure for review of decommissioning costs recoveries. Customer choice commenced for I&M's Michigan customers on January 1, 2002. Effective with that date the rates on I&M's Michigan customers' bills for retail electric service were unbundled to allow customers the opportunity to evaluate the cost of generation service for comparison with other offers. I&M's total rates in Michigan remain unchanged and reflect cost of service. At this time, none of I&M's customers have elected to change suppliers and no competing suppliers are active in I&M's Michigan service territory.

Management has concluded that as of December 31, 2001 the requirements to apply SFAS 71 continue to be met since I&M's rates for generation in Michigan continue to be cost-based regulated. As a result I&M has not yet discontinued regulatory accounting under SFAS 71.

Oklahoma Restructuring

Under Oklahoma restructuring legislature passed in 1997 retail open access and customer choice was scheduled to begin by July 1, 2002.

In June 2001 the Oklahoma Governor signed into law a bill to delay, indefinitely, the implementation of the transition to customer choice and market based pricing under restructuring legislation. Consequently, PSO, the AEP subsidiary doing business in Oklahoma, will remain rate-regulated until further legislation passes and continues the application of SFAS 71 regulatory accounting.

8. Commitments and Contingencies:

Construction and Other Commitments - The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2002-2004 for consolidated domestic and foreign operations are estimated to be $5.4 billion.

APCo, AEP's subsidiary which operates in Virginia and West Virginia, has been seeking regulatory approval to build a new high voltage transmission line for over a decade. Through December 31, 2001 we had invested approximately $40 million in this effort. If the required regulatory approvals are not obtained and the line is not constructed, the $40 million investment would be written off adversely affecting future results of operations and cash flows.

Long-term contracts to acquire fuel for electric generation have been entered into for various terms, the longest of which extends to the year 2014. The contracts provide for periodic price adjustments and contain various clauses that would release the Company from its obligation under certain force majeure conditions.

The AEP System has contracted to sell approximately 1,300 MW of capacity domestically on a long-term basis to unaffiliated utilities. Certain of these contracts totaling 250 MW of capacity are unit power agreements requiring the delivery of energy only if the specified generating unit is available. The power sales contracts expire from 2002 to 2012.

In connection with a lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the obligations of the mining contractor. The contractor's actual obligation outstanding at December 31, 2001 was $75 million.

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo has agreed to provide guarantees of mine reclamation in the amount of $85 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by a third party miner. At December 31, 2001 the cost to reclaim the mine is estimated to be approximately $36 million.

AEP, through certain subsidiaries, has entered into agreements with an unrelated, unconsolidated special purpose entity (SPE) to develop, construct, finance and lease a power generation facility. The SPE will own the power generation facility and lease it to an AEP consolidated subsidiary after construction is completed. The lease will be accounted for as an operating lease with the payment obligations included in the lease footnote. Payments under the operating lease are expected to commence in the first quarter of 2004. AEP will in turn sublease the facility to an unrelated industrial company which will both use the energy produced by the facility and sell excess energy. Another affiliate of AEP has agreed to purchase the excess energy from the subleasee for resale.

The SPE has an aggregate financing commitment from equity and debt participants (Investors) of $427 million. AEP, in its role as construction agent for the SPE, is responsible for completing construction by December 31, 2003. In the event the project is terminated before completion of construction, AEP has the option to either purchase the project for 100% of project costs or terminate the project and make a payment to the Lessor for 89.9% of project costs.

The term of the operating lease between the SPE and the AEP subsidiary is five years with multiple extension options. If all extension options are exercised the total term of the lease would be 30 years. AEP's lease payments to the SPE are sufficient to provide a return to the Investors. At the end of the first five-year lease term or any extension, AEP may renew the lease at fair market value subject to Investor approval; purchase the facility at its original construction cost; or sell the facility, on behalf of the SPE, to an independent third party. If the project is sold and the proceeds from the sale are insufficient to repay the Investors, AEP may be required to make a payment to the Lessor of up to 85% of the project's cost. AEP has guaranteed a portion of the obligations of its subsidiaries to the SPE during the construction and post-construction periods.

As of December 31, 2001, project costs subject to these agreements totaled $168 million, and total costs for the completed facility are expected to be approximately $450 million. Since the lease is accounted for as an operating lease for financial accounting purposes, neither the facility nor the related obligations are reported on AEP's balance sheets. The lease is a variable rate obligation indexed to three-month LIBOR. Consequently as market interest rates increase, the payments under this operating lease will also increase. Annual payments of approximately $12 million represent future minimum payments under the first five-year lease term calculated using the indexed LIBOR rate of 2.85% at December 31, 2001.

OPCo has entered into a purchased power agreement to purchase electricity produced by an unaffiliated entity's three-unit natural gas fired plant that is under construction. The first unit is anticipated to be completed in October 2002 and the agreement will terminate 30 years after the third unit begins operation. Under the terms of the agreement OPCo has the options to run the plant until December 31, 2005 taking 100% of the power generated. For the remainder of the 30 year contract term, OPCo will pay the variable costs to generate the electricity it purchases which could be up to 20% of the plant's capacity. The estimated fixed payments through December 2005 are $55 million.

Nuclear Plants - I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. CPL owns 25.2% of the two-unit 2,500 MW STP. STPNOC operates STP on behalf of the joint owners under licenses granted by the NRC. 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 U.S., the resultant liability could be substantial. By agreement I&M and CPL are partially liable together with all other electric utility companies that own nuclear generating units for a nuclear power plant incident at any nuclear plant in the U.S. 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 adversely affected.

Nuclear Incident Liability – The Price-Anderson Act establishes insurance protection for public liability arising from a nuclear incident at $9.5 billion and covers any incident at a 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 in the U.S. 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. CPL could be assessed $44 million per nuclear incident payable in annual installments of $5 million as its share of a STPNOC assessment. The number of incidents for which payments could be required is not limited.

Insurance coverage for property damage, decommissioning and decontamination at the Cook Plant and STP is carried by I&M and STPNOC in the amount of $1.8 billion each. Cook Plant and STPNOC jointly purchase $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for extra costs resulting from a prolonged accidental outage. I&M and STPNOC utilize an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurer requires a contingent financial obligation of up to $36 million for I&M and $3 million for CPL which is assessable if the insurer's financial resources would be inadequate to pay for losses.

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 KWH for fuel consumed after April 6, 1983 at Cook Plant and STP is being collected from customers and remitted to the U.S. Treasury. Fees and related interest of $220 million for fuel consumed prior to April 7, 1983 at Cook Plant have been recorded as long-term debt. I&M has not paid the government the Cook Plant related pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program. At December 31, 2001, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and approximate the liability. CPL is not liable for any assessments for nuclear fuel consumed prior to April 7, 1983 since the STP units began operation in 1988 and 1989.

Decommissioning and Low Level Waste Accumulation Disposal - Decommissioning costs are accrued over the service lives of the Cook Plant and STP. The licenses to operate the two nuclear units at Cook Plant expire in 2014 and 2017. After expiration of the licenses, Cook Plant is expected to be decommissioned through dismantlement. The estimated cost of decommissioning and low level radioactive waste accumulation disposal costs for Cook Plant ranges from $783 million to $1,481 million in 2000 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. I&M is recovering estimated Cook Plant 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 amount recovered in rates for decommissioning the Cook Plant and deposited in the external fund was $27 million in 2001 and $28 million in 2000 and 1999.

The licenses to operate the two nuclear units at STP expire in 2027 and 2028. After expiration of the licenses, STP is expected to be decommissioned using the decontamination method. CPL estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. CPL is accruing and recovering these decommissioning costs through rates based on the service life of STP at a rate of $8 million per year.

Decommissioning costs recovered from customers are deposited in external trusts. In 2001 and 2000 I&M deposited in its decommissioning trust an additional $12 million and $6 million, respectively, related to special regulatory commission approved funding for decommissioning of the Cook Plant. Trust fund earnings increase the fund assets and the recorded liability and decrease the amount needed to be recovered from ratepayers. Decommissioning costs are recorded in other operation expense.

On the balance sheets, nuclear decommissioning trust assets are included in other assets and a corresponding nuclear decommissioning liability is included in other noncurrent liabilities. At December 31, 2001 and 2000, the decommissioning liability was $699 million and $654 million, respectively.

Shareholders' Litigation - On December 21, 2001, the U.S. District Court for the Southern District of Ohio dismissed a class action lawsuit against AEP and four former or present officers. The class consisted of all persons and entities who purchased or otherwise acquired AEP common stock between July 25, 1997 and June 25, 1999. The complaint alleged that the defendants knowingly violated federal securities laws by disseminating materially false and misleading statements related to the extended Cook Plant outage.

Municipal Franchise Fee Litigation – In 2001 CPL settled litigation regarding municipal franchise fees in Texas. CPL paid $11 million to settle the litigation and be released from any further liability. The City of San Juan, Texas had filed a class action suit in 1996 seeking $300 million in damages.

Texas Base Rate Litigation - In 2001 the Texas Supreme Court denied CPL's request to review a case resulting from a 1997 PUCT base rate order. The Court also denied CPL's rehearing request.

The primary issues were:

- the classification of $800 million of invested capital in STP as ECOM and assigning it a lower return on equity than other generation property;
- and an $18 million disallowance of an affiliate service billings.

Lignite Mining Agreement Litigation – In 2001 SWEPCo settled ongoing litigation concerning lignite mining in Louisiana. Since 1997 SWEPCo has been involved in litigation concerning the mining of lignite from jointly owned lignite reserves. SWEPCo and CLECO are each a 50% owner of Dolet Hills Power Station Unit 1 and jointly own lignite reserves in the Dolet Hills area of northwestern Louisiana. Under terms of a settlement, SWEPCo purchased an unaffiliated mine operator's interest in the mining operations and related debt and other obligations for $86 million.

Federal EPA Complaint and Notice of Violation – Since 1999 the AEP System has been involved in litigation regarding generating plant emissions under the Clean Air Act. Federal EPA and a number of states alleged that AEP System companies and eleven unaffiliated utilities modified certain units at coal-fired generating plants in violation of the Clean Air Act. Federal EPA filed complaints against AEP subsidiaries in U.S. District Court for the Southern District of Ohio. A separate lawsuit initiated by certain special interest groups was consolidated with the Federal EPA case. The alleged modification of the generating units occurred over a 20 year period.

Under the Clean Air Act, if a 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. 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). In March 2001 the District Court ruled claims for civil penalties based on activities that occurred more than five years before the filing date of the complaints cannot be imposed. There is no time limit on claims for injunctive relief.

In February 2001 the government filed a motion requesting a determination that four projects undertaken on units at Sporn, Cardinal and Clinch River plants do not constitute "routine maintenance, repair and replacement" as used in the Clear Air Act. The court denied the motion as premature. Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense.

In January 2002 the U.S. Court of Appeals for the 11th Circuit ruled that TVA may pursue its court challenge of a Federal EPA administrative order charging similar violations to those in the complaints against AEP and other utilities.

Management is unable to estimate the loss or range of loss related to the contingent liability for civil penalties under the Clear Air Act proceedings and unable to predict the timing of resolution of these matters due to the number of alleged violations and the significant number of issues yet to be determined by the Court. In the event the AEP System companies do 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 and market prices for electricity.

In December 2000 Cinergy Corp., an unaffiliated utility, which operates certain plants jointly owned by CSPCo, reached a tentative agreement with Federal EPA and other parties to settle litigation regarding generating plant emissions under the Clean Air Act. Negotiations are continuing between the parties in an attempt to reach final settlement terms. Cinergy's settlement could impact the operation of Zimmer Plant and W.C. Beckjord Generating Station Unit 6 (owned 25.4% and 12.5%, respectively, by CSPCo). Until a final settlement is reached, CSPCo will be unable to determine the settlement's impact on its jointly owned facilities and its results of operations and cash flows.

NOx Reductions - Federal EPA issued a NOx Rule requiring substantial reductions in NOx emissions in a number of eastern states, including certain states in which the AEP System's generating plants are located. The NOx Rule has been upheld on appeal. The compliance date for the NOx Rule is May 31, 2004.

The NOx Rule required states to submit plans to comply with its provisions. In 2000 Federal EPA ruled that eleven states, including certain states in which the AEP System's generating units are located, failed to submit approvable compliance plans. Those states could face stringent sanctions including limits on construction of new sources of air emissions, loss of federal highway funding and possible Federal EPA takeover of state air quality management programs. AEP and other utilities requested that the D.C. Circuit Court review this ruling.

In 2000 Federal EPA also adopted a revised rule (the Section 126 Rule) granting petitions filed by certain northeastern states under the Clean Air Act. The rule imposes emissions reduction requirements comparable to the NOx Rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Affected utilities, including AEP, petitioned the D.C. Circuit Court to review the Section 126 Rule.

After review, the D.C. Circuit Court instructed Federal EPA to justify the methods it used to allocate allowances and project growth for both the NOx Rule and the Section 126 Rule. AEP and other utilities requested that the D.C. Circuit Court vacate the Section 126 Rule or suspend its May 2003 compliance date. On August 24, 2001, the D.C. Circuit Court issued an order tolling the compliance schedule until Federal EPA responds to the Court's remand. Federal EPA has announced that it intends to adopt May 31, 2004, as the compliance date for the Section 126 Rule when it finalizes the NOx budgets for both rules.

In 2000 the Texas Natural Resource Conservation Commission adopted rules requiring significant reductions in NOx emissions from utility sources, including those owned by CPL and SWEPCo. The compliance date is May 2003 for CPL and May 2005 for SWEPCo.

During 2001 selective catalytic reduction (SCR) technology to reduce NOx emissions on OPCo's Gavin Plant commenced operations. Construction of SCR technology at certain other AEP generating units continues with completion scheduled in 2002 through 2006.

Our estimates indicate that compliance with the NOx Rule, the Texas Natural Resource Conservation Commission rule and the Section 126 Rule could result in required capital expenditures of approximately $1.6 billion of which approximately $450 million has been spent through December 31, 2001 for the AEP System. Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the preliminary estimate depending upon the compliance alternatives selected to achieve reductions in NOx emissions. Unless any capital and operating costs of additional pollution control equipment are recovered from customers, they will have an adverse effect on results of operations, cash flows and possibly financial condition.

Merger Litigation – On January 18, 2002, the U.S. Court of Appeals for the District of Columbia ruled that the SEC failed to prove that the June 15, 2000 merger of AEP with CSW meets the requirements of the PUHCA and sent the case back to the SEC for further review. Specifically, the court told the SEC to revisit its conclusion that the merger met PUHCA requirements that utilities be "physically interconnected" and confined to a "single area or region."

In its June 2000 approval of the merger, the SEC agreed with AEP that the companies' systems are integrated because they have transmission access rights to a single high-voltage line through Missouri and also met the PUCHA's single region requirement because it is now technically possible to centrally control the output of power plants across many states. In its ruling, the appeals court said that the SEC failed to explain its conclusions that the transmission integration and single region requirements are satisfied.

Management believes that the merger meets the requirements of the PUHCA and expects the matter to be resolved favorably.

Enron Bankruptcy – At the date of Enron's bankruptcy AEP had open trading contracts and trading accounts receivables and payables with Enron. In addition, on June 1, 2001, we purchased Houston Pipe Line from Enron and entered into a lease arrangement with a subsidiary of Enron for a gas storage facility. At the date of Enron's bankruptcy various HPL related contingencies and indemnities remained unsettled. In the fourth quarter of 2001 AEP provided $47 million ($31 million net of tax) for our estimated loss from the Enron bankruptcy. The amount provided was based on an analysis of contracts where AEP and Enron are counterparties, the offsetting of receivables and payables, the application of deposits from Enron and management's analysis of the HPL related purchase contingencies and indemnifications. If there are any adverse unforeseen developments in the bankruptcy proceedings, our future results of operations, cash flows and possibly financial condition could be adversely impacted.

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

9. Acquisitions and Dispositions:

Acquisitions

On June 1, 2001, AEP, through a wholly owned subsidiary, purchased Houston Pipe Line Company and Lodisco LLC for $727 million from Enron. The acquired assets include 4,200 miles of gas pipeline, a 30-year $274 million prepaid lease of a gas storage facility and certain gas marketing contracts. The purchase method of accounting was used to record the acquisition. According to APB Opinion No. 16 "Business Combinations" AEP recorded the assets acquired and liabilities assumed at their estimated fair values as determined by the Company's management based on information currently available and on current assumptions as to future operations. Based on a preliminary purchase price allocation the excess of cost over fair value of the net assets acquired was approximately $190 million and is recorded as goodwill. SFAS 142 "Goodwill and Other Intangible Assets" treats goodwill as a non-amortized, non-wasting asset effective January 1, 2002. Therefore, goodwill was amortized for only seven months in 2001 on a straight-line basis over 30 years. The purchase method results in the assets, liabilities and earnings of the acquired operations being included in AEP's consolidated financial statements from the purchase date.

SFAS 141 "Business Combinations" apply to all business combinations initiated and consummated after June 30, 2001.

AEP also purchased the following assets or acquired the following businesses from July 1, 2001 through December 31, 2001 for an aggregate total of $1,651 million:

- The Dolet Hills mining operations including existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana. The purchase resulted from a litigation settlement discussed in Note 8, "Commitments and Contingencies". Management expects the acquisition to have minimal impact on results of operations.
- Quaker Coal Company as part of a bankruptcy proceeding settlement and assumed additional liabilities of approximately $58 million. The acquisition includes property, coal reserves, mining operations and royalty interests in Colorado, Kentucky, Ohio, Pennsylvania and West Virginia. AEP will continue to operate the mines and facilities which employ over 800 individuals.
- MEMCO Barge Line that adds 1,200 hopper barges and 30 towboats to AEP's existing barging fleet. MEMCO's 450 employees will continue to operate the barge line. MEMCO also adds major barging operations on the Mississippi and Ohio rivers to AEP's barging operations on the Ohio and Kanawha rivers.
- 4,000 megawatts of UK coal-fired generation that includes Fiddler's Ferry, a four-unit, 2,000-megawatt station on the River Mersey in northwest England, approximately 200 miles from London and Ferrybridge, a four-unit, 2,000-megawatt station on the River Aire in northeast England, approximately 200 miles from London and related coal stocks.
- A 20% equity interest in Caiua, a Brazilian electric operating company which is a subsidiary of Vale. See Note 17, "Power, Distribution and Communications Projects". The Company converted a total of $66 million on an existing loan and accrued interest on that loan into Caiua equity.
- Indian Mesa Wind Project consisting of 160 megawatts of wind generation located near Fort Stockton, Texas.
- Acquired existing contracts and hired 22 key staff from Enron's London-based international coal trading group.

Regarding the 2001 acquisitions management has recorded the assets acquired and liabilities assumed at their estimated fair values in accordance with APB Opinion No. 16 and SFAS 141 as appropriate based on currently available information and on current assumptions as to future operations. Management is in the process of obtaining independent appraisals regarding certain of these acquisitions and evaluating others to refine its determination of fair values. Accordingly the allocation of the purchase prices are subject to revision based on the final determinations.

Dispositions

In March 2001 AEP completed the sale of Frontera, a generating plant that the FERC required to be divested in connection with the merger of AEP and CSW. The sale proceeds were $265 million and resulted in an after tax gain of $46 million.

In July 2001 AEP, through a wholly owned subsidiary, sold its 50% interest in a 120-megawatt generating plant located in Mexico. The sale resulted in an after tax gain of approximately $11 million.

In July 2001 AEP sold coal mines in Ohio and West Virginia and agreed to purchase approximately 34 million tons of coal from the purchaser of the mines through 2008. The sale is expected to have a nominal impact on results of operations and cash flows.

In December 2001 AEP completed the sale of its ownership interests in the Virginia and West Virginia PCS (personal communications services) Alliances for stock. AEP recorded a 25% valuation provision on the stock received and is restricted from selling this stock until after January 1, 2003. In addition, the number of shares AEP can sell each month is limited in order to prevent large swings in the stock price. The sales resulted in an after tax gain of approximately $7 million.

In December 2000 the Company, through a wholly owned subsidiary, committed to negotiate a sale of its 50% investment in Yorkshire, a U.K. electricity supply and distribution company. As a result a $43 million impairment writedown ($30 million after tax) was recorded in the fourth quarter of 2000 to reflect the net loss from the expected sale in the first quarter of 2001. The impairment writedown is included in Other Income on AEP's Consolidated Statements of Income. On February 26, 2001 an agreement to sell the Company's 50% interest in Yorkshire was signed. On April 2, 2001, following the approval of the buyer's shareholders, the sale was completed without further impact on AEP's consolidated earnings.

In December 2000, CSW International sold its investment in a Chilean electric company for $67 million. A net loss on the sale of $13 million ($9 million after tax) is included in Other Income, and includes $26 million ($17 million net of tax) of losses from foreign exchange rate changes that were previously reflected in other comprehensive income. In the second quarter of 2000 management determined that the then existing decline in market value of the shares was other than temporary. As a result the investment was written down by $33 million ($21 million after tax) in June 2000. The total loss from both the write down of the Chilean investment to market in the second quarter and from the sale in the fourth quarter was $46 million ($30 million net of tax).

10. Benefit Plans:

In the U.S. AEP sponsors two qualified pension plans and two nonqualified pension plans. Substantially all employees in the U.S. are covered by one or both of the pension plans. OPEB plans are sponsored by AEP to provide medical and death benefits for retired employees in the U.S.

The foreign pension plans are for employees of SEEBOARD in the U.K. and CitiPower in Australia. The majority of SEEBOARD's employees joined a pension plan that is administered for the U.K.'s electricity industry. The assets of this plan are actuarially valued every three years. SEEBOARD and its participating employees both contribute to the plan. Subsequent to July 1, 1995, new employees of SEEBOARD were no longer able to participate in that plan and two new pension plans were made available. CitiPower sponsors a defined benefit pension plan that covers all employees.

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2001, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		Foreign Pension Plans		U.S. OPEB Plans	
	2001	2000	2001	2000	2001	2000
			(in millions)			
Reconciliation of benefit obligation:						
Obligation at January 1	$3,161	$2,934	$1,179	$1,176	$1,668	$1,365
Service Cost	69	60	12	13	30	29
Interest Cost	232	227	60	64	114	106
Participant Contributions	-	-	4	5	8	7
Plan Amendments	-	(71)(a)	-	-	17 (b)	(67) (c)
Foreign Currency Translation Adjustment	-	-	(36)	(95)	-	-
Actuarial (Gain) Loss	121	218	(62)	80	192	262
Divestures	-	-	-	-	(287) (d)	-
Benefit Payments	(291)	(207)	(58)	(64)	(88)	(85)
Curtailments	-	-	-	-	1	51 (e)
Obligation at December 31	$3,292	$3,161	$1,099	$1,179	$1,655	$1,668
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$3,911	$3,866	$1,290	$1,405	$704	$668
Actual Return on Plan Assets	(182)	250	(131)	55	(31)	2
Company Contributions	-	2	7	-	118	112
Participant Contributions	-	-	4	5	8	7
Foreign Currency Translation Adjustment	-	-	(40)	(111)	-	-
Benefit Payments	(291)	(207)	(58)	(64)	(88)	(85)
Fair value of plan assets at December 31	$3,438	$3,911	$1,072	$1,290	$711	$704
Funded status:						
Funded status at December 31	$146	$ 750	$(27)	$111	$(944)	$(964)
Unrecognized Net Transition (Asset) Obligation	(15)	(23)	-	-	263	298
Unrecognized Prior-Service Cost	(12)	(12)	9	10	17	-
Unrecognized Actuarial (Gain) Loss	35	(628)	74	(67)	649	448
Prepaid Benefit (Accrued Liability)	$154	$ 87	$ 56	$ 54	$ (15)	$(218)

(a) One of the qualified pension plans converted to the cash balance pension formula from a final average pay formula.
(b) Related to the purchase of Houston Pipe Line Company and MEMCo Barge Line.
(c) Change to a service-related formula for retirement health care costs and a 50% of pay life insurance benefit for retiree life insurance.
(d) Related to the sale of Central Ohio Coal Company, Southern Ohio Coal Company and Windsor Coal Company.
(e) Related to the shutdown of Central Ohio Coal Company, Southern Ohio Coal Company and Windsor Coal Company.

The following table provides the amounts for prepaid benefit costs and accrued benefit liability recognized in the consolidated balance sheets as of December 31 of both years. The amounts for additional minimum liability, intangible asset and accumulated other comprehensive income for 2000 were recorded in 2001 and the amounts for 2001 will be recorded in 2002.

	U.S. Pension Plan		Foreign Pension Plans		U.S. OPEB Plans	
	2001	2000	2001	2000	2001	2000
			(in millions)			
Prepaid Benefit Costs	$205	$ 159	$57	$54	$ 1	$ 3
Accrued Benefit Liability	(51)	(72)	(1)	-	(16)	(221)
Additional Minimum Liability	(15)	(24)	-	-	N/A	N/A
Intangible Asset	9	14	-	-	N/A	N/A
Accumulated Other Comprehensive Income	6	10	-	-	N/A	N/A
Net Asset (Liability)	$154	$ 87	$56	$54	$(15)	$(218)
Other Comprehensive (Income) Expense Attributable to Change in Additional Pension Liability Recognition	$(4)	$4	-	-	N/A	N/A

N/A = Not Applicable

Both of the Company's nonqualified pension plans had accumulated benefit obligations in excess of plan assets of $40 million and $26 million at December 31, 2001 and $41 million and $26 million at December 31, 2000. There are no plan assets in the nonqualified plans.

The Company's OPEB plans had accumulated benefit obligations in excess of plan assets of $944 million and $964 million at December 31, 2001 and 2000, respectively.

In late December 2001 AEP purchased generation plants in the UK (see Note 9, "Acquisitions and Dispositions"). The purchase included the pension plan of the existing generation plant employees. In connection with the acquisition, a $10 million liability for the accumulated benefit obligation in excess of plan assets was assumed.

The following table provides the components of net periodic benefit cost for the plans for fiscal years 2001, 2000 and 1999:

	U.S. Pension Plans			Foreign Pension Plans			U.S. OPEB Plans		
	2001	2000	1999	2001	2000	1999	2001	2000	1999
	(in millions)								
Service cost	$ 69	$ 60	$ 71	$ 12	$ 13	$ 15	$ 30	$ 29	$ 33
Interest cost	232	227	211	60	64	59	114	106	90
Expected return on plan assets	(338)	(321)	(299)	(69)	(75)	(71)	(61)	(57)	(49)
Amortization of transition (asset) obligation	(8)	(8)	(8)	-	-	-	30	41	43
Amortization of prior-service cost	-	13	12	1	1	-	-	-	-
Amortization of net actuarial (gain) loss	(24)	(39)	(15)	-	-	-	18	4	5
Net periodic benefit cost (credit)	(69)	(68)	(28)	4	3	3	131	123	122
Curtailment loss(a)	-	-	-	-	-	-	1	79	18
Net periodic benefit cost (credit) after curtailments	$ (69)	$ (68)	$ (28)	$ 4	$ 3	$ 3	$132	$202	$140

(a) Curtailment charges were recognized during 2000 and 1999 for the shutdown of Central Ohio Coal Company, Southern Ohio Coal Company and Windsor Coal Company.

The weighted-average assumptions as of December 31, used in the measurement of the Company's benefit obligations are shown in the following tables:

	U.S. Pension Plans			Foreign Pension Plans			U.S. OPEB Plans		
	2001	2000	1999	2001	2000	1999	2001	2000	1999
Discount rate	7.25%	7.50%	8.00%	5-5.8%	5-5.5%	5.5-6%	7.25%	7.50%	8.00%
Expected return on plan assets	9.00%	9.00%	9.00%	6.1-7.5%	6-7.5%	6.5-7.5%	8.75%	8.75%	8.75%
Rate of compensation increase	3.7%	3.2%	3.8%	4.0%	3.5-4.0%	4-4.5%	N/A	N/A	N/A

For OPEB measurement purposes, an 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2002. The rate was assumed to decrease gradually each year to a rate of 5% through 2005 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in millions)	
Effect on total service and interest cost components of net periodic postretirement health care benefit cost	$ 18	$ (15)
Effect on the health care component of the accumulated postretirement benefit obligation	189	(156)

AEP Savings Plans - AEP Savings Plans are defined contribution plans offered to non-UMWA U.S. employees. The cost for contributions to these plans totaled $55 million in 2001, $37 million in 2000 and $36 million in 1999. Beginning in 2001 AEP's contributions to the plans increased to 4.5% of the initial 6% of employee pay contributed from the previous 3% of the initial 6% of employee base pay contributed.

Other UMWA Benefits - The Company provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees, and their survivors who meet eligibility requirements.

The benefits are administered by UMWA trustees and contributions are made to their trust funds. Contributions are expensed as paid as part of the cost of active mining operations and were not material in 2001, 2000 and 1999.

11. Stock-Based Compensation:

AEP has a Long-term Incentive Plan under which a maximum of 15,700,000 shares of common stock can be issued to key employees. The plan was adopted in 2000.

Under the plan, the exercise price of each option granted equals the market price of AEP's common stock on the date of grant. These options will vest in equal increments, annually, over a three-year period with a maximum exercise term of ten years.

CSW maintained a stock option plan prior to the merger with AEP in 2000. Effective with the merger, all CSW stock options outstanding were converted into AEP stock options at an exchange ratio of one CSW stock option for 0.6 of an AEP stock option. The exercise price for each CSW stock option was adjusted for the exchange ratio. The provisions of the CSW stock option plan will continue in effect until all options expire or there are no longer options outstanding. Under the CSW stock option plan, the option exercise price was equal to the stock's market price on the date of grant. The grant vested over three years, one-third on each of the first three anniversary dates of the grant, and expires 10 years after the original grant date. All CSW stock options are fully vested.

The following table summarizes share activity in the above plans, and the weighted-average exercise price:

	2001		2000		1999	
	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price	Options (in thousands)	Weighted Average Exercise Price
Outstanding at beginning of year	6,610	$36	825	$40	866	$40
Granted	645	$45	6,046	$36	-	$ -
Exercised	(216)	$38	(26)	$36	(22)	$38
Forfeited	(217)	$37	(235)	$39	(19)	$43
Outstanding at end of year	6,822	$37	6,610	$36	825	$40
Options Exercisable at end of year	395	$43	588	$41	707	$42

The weighted-average grant-date fair value of options granted in 2001 and 2000 was $8.01 and $5.50 per share. There were no options granted in 1999. Shares outstanding under the stock option plan have exercise prices ranging from $35 to $49 and a weighted-average remaining contractual life of 8.5 years.

If compensation expense for stock options had been determined based on the fair value at the grant date, net income and earnings per share would have been the pro forma amounts shown below:

	2001	2000	1999
Pro forma net income (in millions)	$959	$264	$972
Pro forma earnings per Share:			
Basic	$2.98	$0.82	$3.03
Diluted	$2.97	$0.82	$3.03

The proceeds received from exercised stock options are included in common stock and paid-in capital.
The pro forma amounts are not representative of the effects on reported net income for future years.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions used to estimate the fair value of options granted:

	2001	2000
Risk Free Interest Rate	4.87%	5.02%
Expected Life	7 years	7 years
Expected Volatility	28.40%	24.75%
Expected Dividend Yield	6.05%	6.02%

12. Business Segments:

In fiscal year 2000, AEP reported the following four business segments: Domestic Electric Utilities; Foreign Energy Delivery; Worldwide Energy Investments; and Other. With this structure, our regulated domestic utility companies were considered single, vertically integrated units, and were reported collectively in the Domestic Electric Utilities segment.

In 2001, we moved toward our goal of functionally and structurally segregating our businesses. The ensuing realignment of our operations resulted in our current business segments, Wholesale, Energy Delivery and Other. The business activities of each of these segments are as follows:

Wholesale
- Generation of electricity for sale to retail and wholesale customers,
- Marketing and trading of electricity and gas.
- Gas pipeline and storage services and other energy supply related business

Energy Delivery
- Domestic electricity transmission
- Domestic electricity distribution

Other
- Foreign electricity distribution and supply investments
- Telecommunication services
- Supporting business and management activities

Segment results of operations for the twelve months ended December 31, 2001, 2000 and 1999 are shown below. These amounts include certain estimates and allocations where necessary.

We have used Earnings before Interest and Income Taxes (EBIT) as a measure of segment operating performance. The EBIT measure is total operating revenues net of total operating expenses and other routine income and deductions from income. It differs from net income in that it does not take into account interest expense or income taxes. EBIT is believed to be a reasonable gauge of results of operations. By excluding interest and income taxes, EBIT does not give guidance regarding the demand of debt service or other interest requirements, or tax liabilities or taxation rates. The effects of interest expense and taxes on overall corporate performance can be seen in the consolidated income statement.

Year	Wholesale	Energy Delivery	Other	Reconciling Adjustments	AEP Consolidated
		(in millions)			
2001					
Revenues from:					
External unaffiliated customers	$55,929	$ 3,356	$ 1,972	$ -	$61,257
Transactions with other operating segments	2,708	20	1,155	(3,883)	-
Segment EBIT	1,418	986	278	(115)	2,567
Depreciation, depletion and amortization expense	597	632	154	-	1,383
Total assets	31,459	12,455	4,541	(1,174)(a)	47,281
Investments in equity method subsidiaries	242	-	414	-	656
Gross property additions	640	844	348	-	1,832
(a) Reconciling adjustments for Total Assets:					
Eliminate intercompany balances				(1,558)	
Corporate assets				404	
Other				(20)	
				(1,174)	
2000					
Revenues from:					
External unaffiliated customers	$31,437	$ 3,174	$2,095	$ -	$36,706
Transactions with other operating segments	1,726	2	750	(2,478)	-
Segment EBIT	1,006	1,017	358	(322)	2,059
Depreciation, depletion and amortization expense	559	506	188	(3)	1,250
Total assets	32,216	14,876	7,124	(866)(b)	53,350
Investments in equity method subsidiaries	140	-	724	-	864
Gross property additions	493	961	319	-	1,773
(b) Reconciling adjustments for Total Assets:					
Eliminate intercompany balances				(955)	
Corporate assets				93	
Other				(4)	
				(866)	
1999					
Revenues from:					
External unaffiliated customers	$19,543	$3,068	$2,134	$ -	$24,745
Transactions with other operating segments	1,038	-	573	(1,611)	-
Segment EBIT	1,146	1,008	392	(82)	2,464
Depreciation, depletion and amortization expense	565	454	196	(3)	1,212
Total assets	18,408	11,224	6,396	(335)(c)	35,693
Investments in equity method subsidiaries	134	-	755	-	889
Gross property additions	390	815	475	-	1,680
(c) Reconciling adjustments for Total Assets:					
Eliminate intercompany balances				(345)	
Other				10	
				(335)	

Geographically our business is transacted primarily in the United States and the United Kingdom with other holdings in a small number of other counties. Results of operations by geographic area are as follows:

Geographic Areas	Revenues			
	United States	United Kingdom	Other Foreign	AEP Consolidated
	(in millions)			
2001	$53,650	$7,201	$406	$61,257
2000	34,300	2,011	395	36,706
1999	22,694	1,705	346	24,745

	Long-Lived Assets			
	United States	United Kingdom	Other Foreign	AEP Consolidated
	(in millions)			
2001	$21,726	$2,158	$659	$24,543
2000	20,463	1,220	710	22,393
1999	19,958	1,124	783	21,865

13. Risk Management, Financial Instruments and Derivatives:

Risk Management

We are subject to market risks in our day to day operations. Our risk policies have been reviewed with the Board of Directors, approved by a Risk Management Committee and administered by Chief Risk Officer. The Risk Management Committee establishes risk limits, approves risk policies, assigns responsibilities regarding the oversight and management of risk and monitors risk levels. This committee receives daily, weekly, and monthly reports regarding compliance with policies, limits and procedures. The committee meets monthly and consists of the Chief Risk Officer, Chief Credit Officer, V.P. Market Risk Oversight, and senior financial and operating managers.

The risks and related strategies that management can employ are:

Risk	Description	Strategy
Price Risk	Volatility in commodity prices	Trading and hedging
Interest Rate Risk	Changes in Interest rates	Hedging
Foreign Exchange Risk	Fluctuations in foreign currency rates	Hedging
Credit Risk	Non-performance on contracts with counterparties	Guarantees, Collateral

We employ physical forward purchase and sale contracts, exchange futures and options, over-the-counter options, swaps, and other derivative contracts to offset price risk where appropriate. However, we engage in trading of electricity, gas and to a lesser degree coal, oil, natural gas liquids, and emission allowances and as a result the Company is subject to price risk. This risk is managed by the management of the trading operations, the Company's Chief Risk Officer and the Risk Management Committee. If the risk from trading activities exceeds certain pre-determined limits, the positions are modified or hedged to reduce the risk to the limits unless specifically approved by the Risk Management Committee. Although we do not hedge all commodity price exposure, management makes informed risk taking decisions supported by the above described risk management controls.

AEP is exposed to risk from changes in the market prices of coal and natural gas used to generate electricity where generation is no longer regulated or where existing fuel clauses are suspended or frozen. The protection afforded by fuel clause recovery mechanisms has either been eliminated by the implementation of customer choice in Ohio (effective January 1, 2001) and in the ERCOT area of Texas (effective January 1, 2002) or frozen by settlement agreements in Indiana, Michigan and West Virginia. To the extent all fuel supply for the generating units in these states are not under fixed price long-term contracts, AEP is subject to market price risk. AEP continues to be protected against market price changes by active fuel clauses in Oklahoma, Arkansas, Louisiana, Kentucky, Virginia and the SPP area of Texas.

We employ fair value hedges, cash flow hedges and swaps to mitigate changes in interest rates or fair values on short and long-term debt when management deems it necessary. We do not hedge all interest rate risk.

We employ cash flow forward hedge contracts to lock-in prices on transactions denominated in foreign currencies where deemed necessary. International subsidiaries use currency swaps to hedge exchange rate fluctuations in debt transactions denominated in foreign currencies. We do not hedge all foreign currency exposure.

Our open trading contracts, including structured transactions, are marked-to-market daily using the price model and price curve(s) corresponding to the instrument. Forwards, futures and swaps are generally valued by subtracting the contract price from the market price and then multiplying the difference by the contract volume and adjusting for net present value and other impacts. Significant estimates in valuing such contracts include forward price curves, volumes, seasonality, weather, and other factors.

Forwards and swaps (which are a series of forwards) are valued based on forward price curves which represent a series of projected prices at which transactions can be executed in the market. The forward price curve includes the market's expectations for prices of a delivered commodity at that future date. The forward price curve is developed from the market bid price, which is the highest price which traders are willing to pay for a contract, and the ask or offer price, which is the lowest price traders are willing to receive for selling a contract.

Options contracts, consisting primarily of options on forwards and spread options, are valued using models, which are variations on Black-Scholes option models. The market-related inputs are the interest rate curve, the underlying commodity forward price curve, and the implied volatility curve. Option prices or volatilities may be quoted in the market. Significant estimates in valuing these contracts include forward price curves, volumes, and other volatilities.

Futures and futures options traded on futures exchanges (primarily oil and gas on Nymex) are valued at the exchange price.

Market prices utilized in valuing all forward contracts, OTC options, swaps and structured transactions represent mid-market price, which is the average of the bid and ask prices. These bids and offers come from brokers, on-line exchanges such as the Intercontinental Exchange, and directly from other counterparties. These prices exist for delivery periods and locations being traded or quoted and vary by period, location and commodity. For periods and locations that are not liquid and for which external information is not readily available, management uses the best information available to develop bid and ask prices and forward curves.

Electricity and gas markets in particular have primary trading hubs or delivery points/regions and less liquid secondary delivery points. In North American natural gas markets, the primary delivery points are generally traded from Henry Hub, Louisiana. The less liquid gas or power trading points may trade as a spread (based on transportation costs, constraints, etc.) from the nearest liquid trading hub. Also, some commodities trade more often and therefore are more liquid than others. For example, peak electricity is a more liquid product than off-peak electricity. Henry Hub gas trades in monthly blocks for up to 36 months and after that only trades in seasonal or calendar blocks. In the near term, forward price curves for gas have a seasonal shape. They are based on market quotes beyond that.

For all these factors, the curve used for valuation is the mid-point. At times bids or offers may not be available due to market events, volatility, constraints, long-dated part of the curve, etc. When this occurs, the Company uses its best judgment to estimate the curve values until actual values are available again. The value used will be based on various factors such as last trade price, recent price trend, product spreads, location spreads (including transportation costs), cross commodity spreads (e.g., heat rate conversion of gas to power), time spreads, cost of carry (e.g., cost of gas storage), marginal production cost, cost of new entrant capacity, and alternative fuel costs. Also, an energy commodity contract's price volatility generally increases as it approaches the delivery month. Spot price volatility (e.g., daily or hourly prices) can cause contract values to change substantially as open positions settle against spot prices. When a portion of a curve has been estimated for a period of time and market changes occur, assumptions are updated to align the company's curve to the market.

The fair values determined are reduced by reserves to adjust for credit risk and liquidity risk. Credit risk is based on credit ratings of counterparties and represents the risk that the counterparty to the contract will fail to perform or fail to pay amounts due AEP. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. The liquidity reserve essentially reserves half of the difference between bids and offers for each open position, such that the wider the bid-offer spread (indicating lower liquidity), the greater the reserve.

We also mark to market derivatives that are not trading contracts in accordance with generally accepted accounting principles. There may be unique models for these transactions, but the curves the company inputs into the models are the same forward curves, which are described above.

We have developed independent controls to evaluate the reasonableness of our valuation models and curves. However, there are inherent risks related to the underlying assumptions in models used to fair value open long-term trading contracts. Therefore, there could be a significant favorable or adverse effect on future results of operations and cash flows if market prices at settlement differ from the price models and curves.

AEP limits credit risk by extending unsecured credit to entities based on internal ratings. AEP uses Moody's Investor Service, Standard and Poor's and qualitative and quantitative data to independently assess the financial health of counterparties on an ongoing basis. This data, in conjunction with the ratings information, is used to determine appropriate risk parameters. AEP also requires cash deposits, letters of credit and parental/affiliate guarantees as security from certain below investment grade counterparties in our normal course of business.

We trade electricity and gas contracts with numerous counterparties. Since our open energy trading contracts are valued based on changes in market prices of the related commodities, our exposures change daily. We believe that our credit and market exposures with any one counterparty is not material to financial condition at December 31, 2001. At December 31, 2001 less than 5% of the counterparties were below investment grade as expressed in terms of Net Mark to Market Assets. Net Mark to Market Assets represents the aggregate difference (either positive or negative) between the forward market price for the remaining term of the contract and the contractual price. The following table approximates counterparty credit quality and exposure.

Counterparty Credit Quality: Year Ending December 31, 2001	Futures, Forward and Swap Contracts	Options	Total
		(in millions)	
AAA/Exchanges	$ 147	$ -	$ 147
AA	140	4	144
A	304	7	311
BBB	932	34	966
Below Investment Grade	56	23	79
Total	$1,579	$68	$1,647

We enter into transactions for electricity and natural gas as part of wholesale trading operations. Electric and gas transactions are executed over-the-counter with counterparties or through brokers. Gas transactions are also executed through brokerage accounts with brokers who are registered with the Commodity Futures Trading Commission. Brokers and counterparties require cash or cash related instruments to be deposited on these transactions as margin against open positions. The combined margin deposits at December 31, 2001 and 2000 was $55 million and $95 million. These magin accounts are restricted and therefore are not included in cash and cash equivalents on the Balance Sheet. The Company can be subject to further margin requirements should related commodity prices change.

Financial Derivatives and Hedging

In the first quarter of 2001, AEP adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS 137 and SFAS 138. SFAS 133 requires that entities recognize all derivatives including fair value hedges as either assets or liabilities and measure such derivatives at fair value. Changes in the fair value of derivatives are included in earnings unless designated as a cash flow hedge. This practice is commonly referred to as mark-to-market accounting. Changes in the fair value of derivatives that are designated as effective cash flow hedges are included in other comprehensive income. AEP recorded a favorable transition adjustment to accumulated other comprehensive income of $27 million at January 1, 2001 in connection with the adoption of SFAS 133. Derivatives included in the transition adjustment are interest rate swaps, foreign currency swaps and commodity swaps, options and futures.

Most of the derivatives identified in the transition adjustment were designated as cash flow hedges and relate to foreign operations.

The amounts of net revenue margins (sales less purchases) in 2001, 2000, and 1999 for trading activities were:

	2001	2000 (in millions)	1999
Net Revenue Margin	$609	$435	$91

The fair value of open trading contracts that are marked-to-market are based on management's best estimates using over-the-counter quotations and exchange prices for short-term open trading contracts, and Company developed price curves for open long-term trading contracts. The fair values of trading contracts at December 31 are:

	2001 Fair Value (in millions)	2000 Fair Value (in millions)
Trading Assets		
Electric		
Futures and Options-NYMEX	$ 11	$ -
Physicals	3,588	8,791
Options - OTC	182	215
Swaps	117	164
Total Trading Assets	$3,898	$9,170
Gas		
Futures and Options-NYMEX	$ 143	$ -
Physicals	238	454
Options - OTC	978	1,266
Swaps	5,646	6,185
Total Trading Assets	$7,005	$7,905
Trading Liabilities		
Electric		
Futures and Options-NYMEX	$ -	$ -
Physicals	(3,382)	(8,852)
Options - OTC	(101)	(133)
Swaps	(126)	(144)
Total Trading Liabilities	$(3,609)	$(9,129)
Gas		
Futures and Options-NYMEX	$ (92)	$ (81)
Physicals	(80)	(419)
Options - OTC	(1,076)	(934)
Swaps	(5,598)	(6,449)
Total Trading Liabilities	$(6,846)	$(7,883)

The FASB's Derivatives Implementation Group (DIG) Issued guidance, effective in the third quarter of 2001, regarding the implementation of SFAS 133 for certain fuel supply contracts with volume optionality and electricity capacity contracts. The guidance concluded that fuel supply contracts with volumetric optionality cannot qualify for a normal purchase or sale exclusion from mark-to-market accounting and provided guidance for determining when electricity capacity conracts can qualify as normal purchases or sales.

Predominantly all of AEP's contracts for coal, gas and electricity, which are recorded on a settlement basis, do not meet the criteria of a financial derivative instrument and qualify as normal purchases or sales. As a result they are exempt from the DIG guidance described above and have not been marked-to-market. Beginning July 1, 2001, the effective date of the DIG guidance, certain of AEP's fuel supply contracts with volumetric optionality that qualify as financial derivative instruments are marked to market with any gain or loss recognized in the income statement. The effect of initially adopting the DIG guidance at July 1, 2001, a favorable earnings mark-to-market effect of $18 million, net of tax, is reported as a cumulative effect of an accounting change on the income statement.

Cash flows from both derivative instruments and trading activities are included in net cash flows from operating activities.

Certain derivatives may be designated for accounting purposes as a hedge of either the fair value of an asset, liability or firm commitment, or a hedge of the variability of cash flows related to a variable-priced asset, liability, commitment or forecasted transaction. To qualify for hedge accounting, the relationship between the hedging instrument and the hedged item must be documented to include the risk management objective and strategy for use of the hedge instrument. At the inception of the hedge and on an ongoing basis, the effectiveness of the hedge is assessed as to whether the hedge is highly effective in offsetting changes in fair value or cash flows of the item being hedged. Changes in the fair value that result from ineffectiveness of a hedge under SFAS 133 are recognized currently in earnings through mark-to-market accounting. Changes in the fair value of effective cash flow hedges are reported in accumulated other comprehensive income if documented at inception. Gains and losses from cash flow hedges in other comprehensive income are reclassified to earnings in the accounting periods in which the variability of cash flows of the hedged items affect earnings.

Cash flow hedges included in Accumulated Other Comprehensive income on the Balance Sheet at December 31, 2001 are:

	Hedging Assets	Hedging Liabilities	Other Comprehensive Income (Loss) After Tax
		(in millions)	
Electric	$16	$ (6)	$ 4
Interest Rate	-	(21)	(12)
Foreign Currency	-	-	5
			$ (3)

The following table represents the activity in Other Comprehensive Income related to the effect of adopting SFAS 133 for derivative contracts that qualify as cash flow hedges at December 31, 2001:

	(in millions)
AEP consolidated	
Transition Adjustment, January 1, 2001	$ 27
Changes in fair value	(1)
Reclasses from OCI to net income	(29)
Accumulated OCI derivative loss, December 31, 2001	$ (3)

Approximately $15 million of net losses from cash flow hedges in accumulated other comprehensive income at December 31, 2001 are expected to be reclassified to net income in the next twelve months as the items being hedged settle. The actual amounts reclassified from accumulated other comprehensive income to net income can differ as a result of market price changes. The maximum term for which the exposure to the variability of future cash flows is being hedged is 5 years.

We have derivatives under SFAS 133 that do not employ hedge accounting and are not energy trading. The derivative's mark to market value at December 31, 2001 was a $22.7 million asset and a $13.1 million liability.

FINANCIAL INSTRUMENTS

Market Valuation of Non-Derivative Financial Instrument

The book values 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 best estimate of its fair value.

The fair values of long-term debt and preferred stock subject to mandatory redemption are based on quoted market prices for the same or similar issues and the current dividend or interest rates offered for instruments with similar maturities. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that we could realize in a current market exchange. The book values and fair values of significant financial instruments at December 31, 2001 and 2000 are summarized in the following tables.

	2001	
	Book Value	Fair Value
	(in millions)	
Long-term Debt	$12,053	$12,002
Preferred Stock Subject To Mandatory Redemption	95	93
Trust Preferred Securities	321	320

	2000	
	Book Value	Fair Value
	(in millions)	
Long-term Debt	$10,754	$10,812
Preferred Stock Subject To Mandatory Redemption	100	98
Trust Preferred Securities	334	326

Other Financial Instruments - Nuclear Trust Funds Recorded at Market Value - The trust investments which are classified as held for sale for decommissioning and SNF disposal, reported in other assets, are recorded at market value in accordance with SFAS 115. At December 31, 2001 and 2000 the fair values of the trust investments were $933 million and $873 million, respectively, and had a cost basis of $839 million and $768 million, respectively. The change in market value in 2001, 2000, and 1999 was a net unrealized holding loss of $11 million, and net unrealized holding gain of $6 million, and $18 million, respectively.

14. Income Taxes:

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

	Year Ended December 31, 2001	2000	1999
		(in millions)	
Federal:			
Current	$406	$ 766	$308
Deferred	60	(237)	129
Total	466	529	437
State:			
Current	61	50	25
Deferred	35	(9)	-
Total	96	41	25
International:			
Current	1	6	3
Deferred	6	21	17
Total	7	27	20
Total Income Tax as Reported	$569	$ 597	$482

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

	Year Ended December 31, 2001	2000	1999
		(in millions)	
Net Income	$ 971	$267	$ 972
Extraordinary Items (net of income tax $20 million in 2001, $44 million in 2000 and $8 million in 1999)	50	35	14
Cumulative Effect of Accounting Change (net of income tax $2 million in 2001)	(18)	-	-
Preferred Stock Dividends	10	11	19
Income Before Preferred Stock Dividends of Subsidiaries	1,013	313	1,005
Income Taxes	569	597	482
Pre-Tax Income	$1,582	$910	$1,487
Income Tax on Pre-Tax Income at Statutory Rate *(35%)*	$554	$319	$520
Increase (Decrease) in Income Tax Resulting from the Following Items:			
Depreciation	48	77	71
Corporate Owned Life Insurance	4	247	2
Investment Tax Credits (net)	(37)	(36)	(38)
Tax Effects of Foreign Operations	(27)	(29)	(54)
Merger Transaction Costs	-	49	-
State Income Taxes	62	26	16
Other	(35)	(56)	(35)
Total Income Taxes as Reported	$569	$597	$482
Effective Income Tax Rate	36.0%	65.5%	32.5%

The following tables show the elements of the net deferred tax liability and the significant temporary differences:

	December 31, 2001	2000
	(in millions)	
Deferred Tax Assets	$ 1,248	$ 1,248
Deferred Tax Liabilities	(6,071)	(6,123)
Net Deferred Tax Liabilities	$(4,823)	$(4,875)
Property Related Temporary Differences	$(3,963)	$(3,935)
Amounts Due From Customers For Future Federal Income Taxes	(245)	(252)
Deferred State Income Taxes	(160)	(251)
Transition Regulatory Assets	(268)	(163)
Regulatory Assets Designated for Securitization	(332)	(332)
All Other (net)	145	58
Net Deferred Tax Liabilities	$(4,823)	$(4,875)

We have settled with the IRS all issues from the audits of our consolidated federal income tax returns for the years prior to 1991. We have received Revenue Agent's Reports from the IRS for the years 1991 through 1996, and have filed protests contesting certain proposed adjustments. Returns for the years 1997 through 2000 are presently being audited by the IRS. 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.

COLI Litigation - On February 20, 2001, the U.S. District Court for the Southern District of Ohio ruled against AEP in its suit against the United States over deductibility of interest claimed by AEP in its consolidated federal income tax returns related to its COLI program. AEP had filed suit to resolve the IRS' assertion that interest deductions for AEP's COLI program should not be allowed. In 1998 and 1999 the Company paid the disputed taxes and interest attributable to COLI interest deductions for taxable years 1991-98 to avoid the potential assessment by the IRS of additional interest on the contested tax. The payments were included in other assets pending the resolution of this matter. As a result of the U.S. District Court's decision to deny the COLI interest deductions, net income was reduced by $319 million in 2000. The Company has filed an appeal of the U.S. District Court's decision with the U.S. Court of Appeals for the 6th Circuit.

The Company has not recognized a deferred tax liability for temporary differences related to investments in certain subsidiaries located outside of the United States because such differences are deemed to be essentially permanent in duration. If the investments were sold, the temporary differences may become taxable resulting in a tax liability of approximately $66 million.

15. Basic and Diluted Earnings Per Share:

The calculation of basic and diluted earnings per share is based on the amounts of income and weighted average shares shown in the table below.

	2001	2000	1999
	(in millions - except per share amounts)		
Income:			
Income before Extraordinary Item and Cumulative Effect	$1,003	$302	$986
Extraordinary Losses (net of tax)	(50)	(35)	(14)
Cumulative Effect of Accounting Change (net of tax)	18	-	-
Net Income	$ 971	$267	$972
Weighted Average Shares:			
Average common Shares outstanding	322	322	321
Assumed conversion of stock options (see Note 11)	1	-	-
Diluted average common shares outstanding	323	322	321
Basic and Diluted Earnings Per Share:			
Income before extraordinary item and cumulative effect	$ 3.11	$0.94	$3.07
Extraordinary losses (net of tax)	(0.16)	(0.11)	(0.04)
Cumulative effect of accounting change (net of tax)	0.06	-	-
	$ 3.01	$0.83	$3.03

The assumed conversion of stock options does not affect income for purposes of calculating diluted earnings per share. Basic and diluted EPS are the same in 2001, 2000 and 1999 since the effect on weighted average shares outstanding is little or nil.

16. Supplementary Information:

	Year Ended December 31, 2001	2000	1999
	(in millions)		
Purchased Power - Ohio Valley Electric Corporation (44.2% owned by AEP System)	$127	$86	$64
Cash was paid for:			
Interest (net of capitalized amounts)	$972	$842	$979
Income Taxes	$569	$449	$270
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	$17	$118	$80
Assumption of Liabilities Related to Acquisitions	$171	-	-
Exchange of Communication Investment for Common Stock	$5	-	-

17. Power, Distribution and Communications Projects:

Power Projects

AEP owns interests of 50% or less in domestic unregulated power plants with a capacity of 1,483 MW located in Colorado, Florida and Texas. In addition to the domestic projects, AEP has equity interests in international power plants totaling 1,788 MW. AEP has other projects in various stages of development.

Investments in power projects that are 50% or less owned are accounted for by the equity method and reported in investments in power, distribution and communications projects on the balance sheet. At December 31, 2001, six domestic and four international power projects are accounted for under the equity method. The six domestic projects are combined cycle gas turbines that provide steam to a host commercial customer and are considered Qualifying Facilities (QF) under the Public Utilities Regulatory Policies Act of 1978. The four international power plants are classified as Foreign Utility Companies (FUCO) under the Energy Policies Act of 1992. All of the power projects accounted for under the equity method have unrelated third-party partners.

All of the above power projects have project-level financing, which is non-recourse to AEP. AEP or AEP subsidiaries have guaranteed $30 million of domestic partnership obligations for performance under power purchase agreements and for debt service reserves in lieu of cash deposits. AEP has guaranteed $94 million of additional equity for two projects.

Distribution Projects

We own a 44% equity interest in Vale, a Brazilian electric operating company which was purchased for a total of $149 million. On December 1, 2001 we converted a $66 million note receivable and accrued interest into a 20% equity interest in Caiua (Brazilian electric operating company), a subsidiary of Vale. Vale and Caiua have experienced losses from operations and our investment has been affected by the devaluation of the Brazilian Real. The cumulative equity share of operating and foreign currency translation losses through December 31, 2001 is approximately $46 million and $54 million, respectively, net of tax. The cumulative equity share of operating and foreign currency translation losses through December 31, 2000 is approximately $33 million and $49 million, respectively, net of tax. Both investments are covered by a put option, which, if exercised, requires our partners in Vale to purchase our Vale and Caiua shares at a minimum price equal to the U.S. dollar equivalent of the original purchase price. As a result, management has concluded that the investment carrying amount should not be reduced below the put option value unless it is deemed to be an other than temporary impairment and our partners in Vale are deemed unable to fulfill their responsibilities under the put option. Management has evaluated through an independent third-party, the ability of its Vale partners to fulfill their responsibilities under the put option agreement and has concluded that our partners should be able to fulfill their responsibilities.

Management believes that the decline in the value of its investment in Vale in US dollars is not other than temporary. As a result and pursuant to the put option agreement, these losses have not been applied to reduce the carrying values of the Vale and Caiua investments. As a result we will not recognize any future earnings from Vale and Caiua until the operating losses are recovered. Should the impairment of our investment become other than temporary due to our partners in Vale becoming unable to fulfill their responsibilities, it would have an adverse effect on future results of operations.

Management will continue to monitor both the status of the losses and of its partners ability to fulfill its obligations under the put.

Communication Projects

AEP provides telecommunication services to businesses and telecommunication companies through a broadband fiber optic network. AEP's investment in the network include fiber optic cable, electronic equipment and colocation facilities that house the equipment. The investments are both owned and leased with a majority of the leased investments being indefeasible rights of use (IRUs) for fiber optic cable for periods ranging from 20 to 30 years. Telecommunication revenue is accounted for using the accrual method of accounting as service is rendered over the contractual term. Lease obligations related to these investment are included in the lease payment amounts disclosed in the lease note.

AEP has a 46.25% ownership interest in a joint venture, AFN networks, LLC (AFN), which is engaged in the operation and construction of a fiber optic network. AFN both owns and leases fiber optic cable and electronic equipment with the majority of leases being IRUs of fiber optic cable for periods ranging from 20 to 25 years. AEP accounts for AFN under the equity method of accounting and has recorded its pro rata share of the losses during the start up phase. AEP has a credit agreement with AFN that enables AFN to borrow up to $91.5 million at market interest rates to finance their construction and operations. The amount available to AFN at December 31, 2001 is $61 million.

AEP has a 50% ownership interest in a joint venture, American Fiber Touch, LLC (AFT), that is constructing a fiber optic line from Missouri to Illinois. AEP accounts for AFT under the equity method of accounting and has recorded its pro rata share of the losses of AFT during the start up phase. AEP has recently decided to withdraw from this venture and fully provided for the expected loss in exiting the joint venture in December 2001.

18. 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.

Lease rentals for both operating and capital leases are charged to operating expenses in accordance with rate-making treatment for regulated operations. Capital leases for non-regulated property are accounted for as if the assets were owned and financed. The components of year ended December 31, rental costs are as follows:

	Year Ended December 31, 2001	2000	1999
	(in millions)		
Lease Payments on Operating Leases	$296	$236	$247
Amortization of Capital Leases	85	121	97
Interest on Capital Leases	22	38	35
Total Lease Rental Costs	$403	$395	$379

Property, plant and equipment under capital leases and related obligations recorded on the Consolidated Balance Sheets are as follows:

	December 31, 2001	2000
	(in millions)	
Property, Plant and Equipment:		
Production	$ 40	$ 42
Distribution	177	151
Other:		
Nuclear Fuel (net amortization)	-	90
Mining and Other Assets	722	619
Total Property, Plant and Equipment	939	902
Accumulated Amortization	256	288
Net Property, Plant and Equipment	$683	$614
Obligations Under Capital Leases:		
Noncurrent Liability	$356	$419
Liability Due Within One Year	95	195
Total	$451	$614

Future minimum lease payments consisted of the following at December 31, 2001:

	Capital Leases	Noncancellable Operating Leases
	(in millions)	
2002	$ 96	$ 286
2003	81	271
2004	63	255
2005	49	245
2006	42	243
Later Years	397	2,671
Total Future Minimum Lease Payments	728	$3,971
Less Estimated Interest Element	277	
Estimated Present Value of Future Minimum Lease Payments	$451	

Operating leases include lease agreements with special purpose entities related to Rockport Plant Unit 2 and the Gavin Plant's flue gas desulfurization system (Gavin Scrubbers). The Rockport Plant lease resulted from a sale and leaseback transaction in 1989. The gain from the sale was deferred and is being amortized over the term of the lease which expires in 2022. The Gavin Scrubber lease expires in 2009. AEP has no ownership interest in the special purpose entities and does not guarantee their debt. The special purpose entities are not consolidated in AEP's financial statements in accordance with applicable accounting standards. As a result, neither the leased plant and equipment nor the debt of the special purpose entities is included on AEP's balance sheet. The future lease payment obligations to the special purpose entities are included in the above table of future minimum lease payments under noncancellable operating leases.

19. Lines of Credit and Sale of Receivables:

The AEP System uses short-term debt, primarily commercial paper, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a money pool to coordinate short-term borrowings for certain subsidiaries and also incurs borrowings outside the money pool for other subsidiaries. As of December 31, 2001, AEP had revolving credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2001, AEP had $3.2 billion outstanding in short-term borrowings of which $2.9 billion was under these credit facilities. The maximum amount of such short-term borrowings outstanding during the year, which had a weighted average interest rate for the year of 4.95%, was $3.3 billion during March 2001.

Outstanding short-term debt for AEP Consolidated consisted of:

	December 31, 2001	December 31, 2000
	(in millions)	
Balance Outstanding:		
Notes Payable	$ 207	$ 193
Commercial paper	2,948	4,140
Total	$3,155	$4,333

AEP Credit, which does not participate in the money pool, issued commercial paper on a stand-alone basis up to May 30, 2001. AEP Credit provides low-cost financing for utilites, including both AEP's electric utility operating companies and non-affiliates, through factoring receivables which arise primarily from the sale and delivery of electricity in the ordinary course of business. In January 2002 AEP Credit stopped purchasing accounts receivable from non-affiliated electric utility companies.

On May 30, 2001, AEP Credit stopped issuing commercial paper and allowed its $2 billion unsecured revolving credit facility to mature. Funding needs were replaced on May 30, 2001 by a $1.5 billion variable funding note. The variable funding note was, in turn, replaced on December 31, 2001 when AEP Credit entered into a sale of receivables agreement with a group of banks and commercial paper conduits.

Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquired from its clients to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140 allowing the receivables to be taken off of AEP Credit's balance sheet. AEP has no ownership interest in the commercial paper conduits and does not consolidate these entities in accordance with GAAP. We continue to service the receivables. At December 31, 2001, the banks had a $1.2 billion commitment under the sale of receivables agreement to purchase receivables from AEP Credit of which $1 billion was outstanding. Of the $1 billion of receivables sold, $485 million respresented non-affiliate receivables. The commitment available under the sale of receivables agreement declines to $1.1 billion on January 31, 2002 and to $900 million on February 28, 2002, where it remains until the expiration of the commitment on May 30, 2002. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of the receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts.

At year ended December 31, 2001, AEP Credit had:

	$ Millions
Accounts Receivable Sold	1,045
Accounts Receivable Retained Interest Less Uncollectible Accounts and Pledged as Collateral	143
Deferred Revenue from Servicing Accounts Receivable	5
Loss on Sale of Accounts Receivable	8
Initial Variable Discount Rate	2.28%
Retained Interest if 10% Adverse change in Uncollectible Accounts	142
Retained Interest if 20% Adverse change in Uncollectible Accounts	140

Historical loss and delinquency amount for the Customer Accounts Receivable managed portfolio for the year ended December 31, 2001.

	Face Value December 31, 2001 $ Millions
Customer Accounts Receivable Retained	$ 626
Miscellaneous Accounts Receivable Retained	1,365
Allowance for Uncollectible Accounts Retained	(109)
Total Net Balance Sheet Accounts Receivable	1,882
Customer Accounts Receivable Securitized (Affiliate)	560
Customer Accounts Receivable Securitized (Non-Affiliate)	485
Total Accounts Receivable managed	$2,927
Net Uncollectible Accounts Written off for the Year Ended December 31, 2001	87

Customer Accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit as a pool between affiliate and non-affiliate accounts receivable. Miscellaneous Account Receivable have been fully retained and not securitized.

Delinquent Customer Accounts Receivable over 60 days old at December 31, 2001:

	(in millions)
Affiliated	$ 92
Non-Affiliated	17
Total	$109

20. Unaudited Quarterly Financial Information:

	2001 Quarterly Periods Ended			
	March 31	June 30	Sept. 30	Dec. 31
(In Millions - Except Per Share Amounts)				
Operating Revenues	$14,165	$14,528	$18,385	$14,179
Operating Income	601	672	862	260
Income Before Extraordinary Items and Cumulative Effect	266	280	403	54
Net Income	266	232	421	52
Earnings per Share Before Extraordinary Items and Cumulative Effect*	0.83	0.87	1.25	0.17
Earnings per Share**	0.83	0.72	1.31	0.16

	2000 Quarterly Periods Ended			
	March 31	June 30	Sept. 30	Dec. 31
(In Millions - Except Per Share Amounts)				
Operating Revenues	$6,117	$8,137	$11,608	$10,844
Operating Income	428	308	873	395
Income (Loss) Before Extraordinary Items and Cumulative Effect	140	(18)	403	(223)
Net Income (Loss)	140	(9)	359	(223)
Earnings (Loss) per Share Before Extraordinary Items and Cumulative Effect	0.43	(0.06)	1.25	(0.68)
Earnings (Loss) per Share	0.43	(0.03)	1.11	(0.68)

* Amounts for 2001 do not add to $3.11 earnings per share before extraordinary items and cumulative effect due to rounding.
** Amounts for 2001 do not add to $3.01 earnings per share due to rounding.

Earnings for the fourth quarter 2001 increased $275 million from the prior year primarily due to the effect of charges recorded in 2000 from a ruling by the IRS disallowing interest deductions from AEP's COLI program and a write down for the proposed sale of Yorkshire. Fourth quarter 2001 earnings were also favorably impacted by the return to service in December 2000 of Unit 1 of the Cook Plant after an extended outage and the receipt of a contract cancellation fee from a non-affiliated factoring client of AEP Credit.

21. Trust Preferred Securities:

The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of CPL, PSO and SWEPCo were outstanding at December 31, 2001 and December 31, 2000. They are classified on the balance sheets as Certain Subsidiaries Obligated, Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely Junior Subordinated Debentures of Such Subsidiaries. The Junior Subordinated Debentures mature on April 30, 2037. CPL reacquired 490,000 and 60,000 trust preferred units during 2001 and 2000, respectively.

Business Trust	Security	Units issued/ Outstanding At 12/31/01	Amount at December 31, 2001	2000	Description of Underlying Debentures of Registrant
			(in millions)		
CPL Capital I	8.00%, Series A	5,450,000	$136	$149	CPL, $141 million, 8.00%, Series A
PSO Capital I	8.00%, Series A	3,000,000	75	75	PSO, $77 million, 8.00%, Series A
SWEPCo Capital I	7.875%, Series A	4,400,000	110	110	SWEPCO, $113 million, 7.875%, Series A
		12,850,000	$321	$334	

Each of the business trusts is treated as a subsidiary of its parent company. The only assets of the business trusts are the subordinated debentures issued by their parent company as specified above. In addition to the obligations under their subordinated debentures, each of the parent companies has also agreed to a security obligation which represents a full and unconditional guarantee of its capital trust obligation.

22. Minority Interest in Finance Subsidiary:

In August 2001, AEP formed Caddis Partners, LLC (Caddis), a consolidated subsidiary, and sold a non-controlling preferred member interest in Caddis to an unconsolidated special purpose entity (Steelhead) for $750 million. Under the provisions of the Caddis formation agreements, the preferred member interest receives quarterly a preferred return equal to an adjusted floating reference rate (4.413% at December 31, 2001). The $750 million received replaces interim funding used to acquire Houston Pipe Line Company in June 2001.

The preferred interest is supported by natural gas pipeline assets and $321.4 million of preferred stock issued by an AEP subsidiary to the AEP affiliate which has the managing member interest in Caddis. Such preferred stock is convertible into common stock of AEP upon the occurrence of certain events. AEP can elect not to have the transaction supported by such preferred stock if the preferred interest were reduced by $225 million. In addition, Caddis has the right to redeem the preferred member interest at any time.

The initial period of the preferred interest is through August 2006. At the end of the initial period, Caddis will either reset the preferred rate, re-market the preferred member interests to new investors, redeem the preferred member interests, in whole or in part including accrued return, or liquidate in accordance with the provisions of applicable agreements.

Steelhead has the right to terminate the transaction and liquidate Caddis upon the occurrence of certain events including a default in the payment of the preferred return. Steelhead's rights include: forcing a liquidation of Caddis and acting as the liquidator, and requiring the conversion of the $321.4 million of AEP subsidiary preferred stock into AEP common stock. If the preferred member interest exercised its rights to liquidate under these conditions, then AEP would evaluate whether to refinance at that time or relinquish the assets that support the preferred member interest. Liquidation of the preferred interest or of Caddis could impact AEP's liquidity.

Caddis and the AEP subsidiary which acts as its managing member are each a limited liability company, with a separate existence and identity from its members, and the assets of each are separate and legally distinct from AEP. The results of operations, cash flows and financial position of Caddis and such managing member are consolidated with AEP for financial reporting purposes. The preferred member interest and payments of the preferred return are reported on AEP's income statement and balance sheet as Minority Interest in Finance Subsidiary.

SCHEDULE OF CONSOLIDATED CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

	December 31, 2001			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(f)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	614,608	$61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	333,100	$33
6.02% - 6-7/8% (c)	$100	1,650,000	513,450	52
7% (e)	(e)	250,000	100,000	10
Total Subject to Mandatory Redemption (c)				$95

	December 31, 2000			
	Call Price per Share (a)	Shares Authorized(b)	Shares Outstanding(f)	Amount (In Millions)
Not Subject to Mandatory Redemption:				
4.00% - 5.00%	$102-$110	1,525,903	614,608	$ 61
Subject to Mandatory Redemption:				
5.90% - 5.92% (c)	(d)	1,950,000	333,100	$ 33
6.02% - 6-7/8% (c)	$100	1,650,000	513,450	52
7% (e)	(e)	250,000	150,000	15
Total Subject to Mandatory Redemption (c)				$100

NOTES TO SCHEDULE OF CUMULATIVE PREFERRED STOCKS OF SUBSIDIARIES

(a) At the option of the subsidiary the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares.
(b) As of December 31, 2001 the subsidiaries had 13,642,750, 22,200,000 and 7,713,495 shares of $100, $25 and no par value preferred stock, respectively, that were authorized but unissued.
(c) Shares outstanding and related amounts are stated net of applicable retirements through sinking funds (generally at par) and reacquisitions of shares in anticipation of future requirements. The subsidiaries reacquired enough shares in 1997 to meet all sinking fund requirements on certain series until 2008 and on certain series until 2009 when all remaining outstanding shares must be redeemed. The sinking fund provisions of the series subject to mandatory redemption aggregate (after deducting sinking fund requirements) of $5 million in 2002, and $5 million in 2003.
(d) Not callable prior to 2003; after that the call price is $100 per share.
(e) With sinking fund.
(f) The number of shares of preferred stock redeemed is 50,000 shares in 2001, 209,563 shares in 2000 and 1,698,276 shares in 1999.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

Maturity	Weighted Average Interest Rate December 31, 2001	Interest Rates at December 31, 2001	Interest Rates at December 31, 2000	December 31, 2001	December 31, 2000
				(in millions)	
FIRST MORTGAGE BONDS (a)					
2001-2003	6.95%	6.00%-7.70%	5.91%-8.95%	$ 852	$ 1,247
2004-2008	6.98%	6-1/8%-8.00%	6-1/8%-8%	1,092	1,140
2020-2025	7.66%	6-7/8%-8.80%	6-7/8%-8.80%	850	1,104
INSTALLMENT PURCHASE CONTRACTS (b)					
2001-2009	4.30%	1.80%-7.70%	4.90%-7.70%	446	234
2011-2030	5.88%	1.55%-8.20%	4.875%-8.20%	1,234	1,447
NOTES PAYABLE (c)					
2001-2021	5.41%	4.0483%-9.60%	6.20%-9.60%	2,237	1,181
SENIOR UNSECURED NOTES					
2001-2004	4.81%	2.31%-7.45%	6.50%-7.45%	1,874	2,049
2005-2009	6.24%	6.125%-6.91%	6.24%-6.91%	1,763	475
2038	7.30%	7.20%-7-3/8%	7.20%-7-3/8%	340	340
JUNIOR DEBENTURES					
2025-2038	8.05%	7.60%-8.72%	7.60%-8.72%	618	620
YANKEE BONDS AND EURO BONDS					
2001-2006	8.71%	8.50%-8.875%	7.98%-8.875%	479	684
OTHER LONG-TERM DEBT (d)				308	280
Unamortized Discount (net)				(40)	(47)
Total Long-term Debt Outstanding (e)				12,053	10,754
Less Portion Due Within One Year				2,300	1,152
Long-term Portion				$ 9,753	$ 9,602

NOTES TO SCHEDULE OF CONSOLIDATED LONG-TERM DEBT OF SUBSIDIARIES

(a) First mortgage bonds are secured by first mortgage liens on electric property, plant and equipment.
(b) For certain series of installment purchase contracts interest rates are subject to periodic adjustment. Certain series will be purchased on demand at periodic interest-adjustment dates. Letters of credit from banks and standby bond purchase agreements support certain series.
(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(d) Other long-term debt primarily consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 8, “Commitments and Contingencies” of the Notes to Consolidated Financial Statements) and financing obligation under sale lease back agreements.
(e) Long-term debt outstanding at December 31, 2001 is payable as follows:

Principal Amount	(in millions)
2002	$ 2,300
2003	2,086
2004	902
2005	616
2006	1,943
Later Years	4,246
Total Principal Amount	12,093
Unamortized Discount	40
Total	$12,053

Management's Responsibility

The management of American Electric Power Company, Inc. is responsible for the integrity and objectivity of the information and representations in this annual report, including the consolidated financial statements. These statements have been prepared in conformity with accounting principles generally accepted in the U.S., using informed estimates where appropriate, to reflect the Company's financial condition and results of operations. The information in other sections of the annual report is consistent with these statements.

The Company's Board of Directors has oversight responsibilities for determining that management has fulfilled its obligation in the preparation of the consolidated financial statements and in the ongoing examination of the Company's established internal control structure over financial reporting. The Audit Committee, which consists solely of outside directors and which reports directly to the Board of Directors, meets regularly with management, Deloitte & Touche LLP - independent auditors and the Company's internal audit staff to discuss accounting, auditing and reporting matters. To ensure auditor independence, both Deloitte & Touche LLP and the internal audit staff have unrestricted access to the Audit Committee.

The consolidated financial statements have been audited by Deloitte & Touche LLP, whose report appears on the next page. The auditors provide an objective, independent review as to management's discharge of its responsibilities insofar as they relate to the fairness of the Company's reported financial condition and results of operations. Their audit includes procedures believed by them to provide reasonable assurance that the consolidated financial statements are free of material misstatement and includes an evaluation of the Company's internal control structure over financial reporting.

Independent Auditors' Report

To the Shareholders and Board of Directors
of American Electric Power Company, Inc.:

We have audited the consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, cash flows, common shareholders' equity and comprehensive income, for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits. The consolidated financial statements give retroactive effect to the merger of American Electric Power Company, Inc. and its subsidiaries and Central and South West Corporation and its subsidiaries, which has been accounted for as a pooling of interests as described in Note 3 to the consolidated financial statements. We did not audit the consolidated statements of income, cash flows, and common shareholders' equity and comprehensive income of Central and South West Corporation and its subsidiaries for the year ended December 31, 1999, which statements reflect total revenues of $5,516,000,000 for the year ended December 31, 1999. Those consolidated statements, before the restatement described in Note 3, were audited by other auditors whose report, dated February 25, 2000, has been furnished to us, and our opinion, insofar as it relates to those amounts included for Central and South West Corporation and its subsidiaries for 1999, is based solely on the report of such other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and its subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

We also audited the adjustments described in Note 3 that were applied to restate the 1999 financial statements to give retroactive effect to the conforming change in the method of accounting for vacation pay accruals. In our opinion, such adjustments are appropriate and have been properly applied.

Deloitte & Touche LLP

Deloitte & Touche LLP
Columbus, Ohio
February 22, 2002

FORM 10-K ANNUAL REPORT

The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 2002 at no cost to shareholders. Please address requests for copies to:

Geoffrey C. Dean
Director of Financial Reporting
American Electric Power Service Corporation
26th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

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