Appendix A to the
Proxy Statement

American Electric Power

2002 Annual Report

Audited Consolidated Financial Statements and Management's Discussion and Analysis

AMERICAN ELECTRIC POWER
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CONTENTS

Common Stock and Dividend Information

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

Quarter Ended	High	Low	Quarter-end Closing Price	Dividend
March 2002	$47.08	$39.70	$46.09	$0.60
June 2002	48.80	39.00	40.02	0.60
September 2002	40.37	22.74	28.51	0.60
December 2002	30.55	15.10	27.33	0.60
March 2001	$48.10	$39.25	$47.00	$0.60
June 2001	51.20	45.10	46.17	0.60
September 2001	48.90	41.50	43.23	0.60
December 2001	46.95	39.70	43.53	0.60

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2002, AEP had approximately 144,000 shareholders of record. In 2003 management recommended that the Company reduce dividends by approximately 40% after payment of the March 2003 dividend which was approved by the Company's Board of Directors at the current level of $0.60 per share.

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 consolidated subsidiaries.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated and non-affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
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.
AEP West companies	PSO, SWEPCo, TCC and TNC.
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 (the FERC overturned earlier approvals of this RTO in December 2001).
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 [legal name changed to AEP Texas Central Company (TCC) effective December 2002]. See TCC.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
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.
MISO	Midwest Independent System Operator (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.
MTM	Mark-to-Market.
MTN	Medium Term Notes.
MW	Megawatt.
MWH	Megawatthour.
NEIL	Nuclear Electric Insurance Limited.
NOx	Nitrogen oxide.
NOx Rule	A final rule issued by Federal EPA which requires NOx reductions in 22 eastern states including seven of the states in which AEP companies operate.
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.
Registrant Subsidiaries	AEP subsidiaries who are SEC registrants; AEGCo, APCo, CSPCo, I&M, KPCo, OPCo, PSO, SWEPCo, TCC and TNC.
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 133 .... Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.
SNF .... Spent Nuclear Fuel.
SPP .... Southwest Power Pool.
STP .... South Texas Project Nuclear Generating Plant, owned 25.2% by AEP Texas Central 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 TCC.
Superfund .... The Comprehensive Environmental, Response, Compensation and Liability Act.
SWEPCo .... Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC .... AEP Texas Central Company, an AEP electric utility subsidiary [formerly known as Central Power and Light Company (CPL)].
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.
TNC .... AEP Texas North Company, an AEP electric utility subsidiary [formerly known as West Texas Utilities Company (WTU)].
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 [legal name changed to AEP Texas North Company (TNC) effective December 2002]. See TNC.
Yorkshire .... Yorkshire Electricity Group plc, a U.K. regional electricity company owned jointly by AEP and New Century Energies until April 2001.
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.

FORWARD LOOKING INFORMATION

This report made by AEP contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP believes that its expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Electric load and customer growth.
- Abnormal weather conditions.
- Available sources and costs of fuels.
- Availability of generating capacity.
- The speed and degree to which competition is introduced to our service territories.
- The ability to recover stranded costs in connection with possible/proposed deregulation.
- New legislation and government regulation.
- Oversight and/or investigation of the energy sector or its participants.
- The ability of AEP to successfully control its costs.
- The success of acquiring new business ventures and disposing of existing investments that no longer match our corporate profile.
- International and country-specific developments affecting AEP's foreign investments including the disposition of any current foreign investments and potential additional foreign investments.
- The economic climate and growth in AEP's service territory and changes in market demand and demographic patterns.
- Inflationary trends.
- Electricity and gas market prices.
- Interest rates.
- Liquidity in the banking, capital and wholesale power markets.
- Actions of rating agencies.
- Changes in technology, including the increased use of distributed generation within our transmission and distribution service territory.
- Other risks and unforeseen events, including wars, the effects of terrorism, embargoes and other catastrophic events.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

Selected Consolidated Financial Data

Year Ended December 31,	2002	2001	2000	1999	1998
OPERATIONS STATEMENTS DATA (in millions):					
Total Revenues	$14,555	$12,767	$11,113	$10,019	$14,080
Operating Income	1,263	2,182	1,774	2,061	2,046
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	21	917	180	869	859
Discontinued Operations Income (Loss)	(190)	86	122	117	116
Extraordinary Losses	-	(50)	(35)	(14)	-
Cumulative Effect of Accounting Change Gain (Loss)	(350)	18	-	-	-
Net Income (Loss)	(519)	971	267	972	975

December 31,	2002	2001	2000	1999	1998
BALANCE SHEET DATA (in millions):					
Property, Plant and Equipment	$37,857	$37,414	$34,895	$33,930	$32,400
Accumulated Depreciation and Amortization	16,173	15,310	14,899	14,266	13,374
Net Property, Plant and Equipment	$21,684	$22,104	$19,996	$19,664	$19,026
Total Assets	$34,741	$39,297	$46,633	$35,296	$33,418
Common Shareholders' Equity	7,064	8,229	8,054	8,673	8,452
Cumulative Preferred Stocks of Subsidiaries*	145	156	161	182	350
Trust Preferred Securities	321	321	334	335	335
Long-term Debt*	10,496	9,505	8,980	9,471	9,215
Obligations Under Capital Leases*	228	451	614	610	539

Year Ended December 31,	2002	2001	2000	1999	1998
COMMON STOCK DATA:					
Earnings per Common Share:					
Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$ 0.06	$ 2.85	$ 0.56	$ 2.71	$2.70
Discontinued Operations	(0.57)	0.26	0.38	0.36	0.36
Extraordinary Losses	-	(0.16)	(0.11)	(0.04)	-
Cumulative Effect of Accounting Change	(1.06)	0.06	-	-	-
Earnings (Loss) Per Share	$ (1.57)	$ 3.01	$ 0.83	$ 3.03	$3.06
Average Number of Shares Outstanding (in millions)	332	322	322	321	318
Market Price Range: High	$ 48.80	$51.20	$48-15/16	$48-3/16	$53-5/16
Low	15.10	39.25	25-15/16	30-9/16	42-1/16
Year-end Market Price	27.33	43.53	46-1/2	32-1/8	47-1/16
Cash Dividends on Common**	$ 2.40	$2.40	$2.40	$2.40	$2.40
Dividend Payout Ratio**	(152.9)%	79.7%	289.2%	79.2%	78.4%
Book Value per Share	$20.85	$25.54	$25.01	$26.96	$26.46

*Including portion due within one year. Long-term Debt includes Equity Unit Senior Notes.

**Based on AEP historical dividend rate. See “Common Stock and Dividend Information” on page 2 regarding the potential reduction of future dividends.

American Electric Power Company, Inc. (AEP or the Company) is one of the largest investor owned electric public utility holding companies in the U.S. We provide generation, transmission and distribution service to almost five 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 have a vast portfolio of assets including:

- 38,000 megawatts of generating capacity, the largest complement of generation in the U.S., the majority of which has a significant cost advantage in our market areas
- 4,000 megawatts of generating capacity in the U.K., a country which is currently experiencing excess generation capacity
- 38,000 miles of transmission lines, the backbone of the electric interconnection grid in the Eastern U.S.
- 186,000 miles of distribution lines that support delivery of electricity to our customers' premises
- Substantial coal transportation assets (7,000 railcars, 1,800 barges, 37 tug boats and two coal handling terminals with 20 million tons of annual capacity)
- 6,400 miles of gas pipelines in Louisiana and Texas with 128 Bcf of gas storage facilities

Business Strategy

We plan to focus on utility operations in the U.S. We continue to participate in wholesale electricity and natural gas markets. Weakness in these markets after the collapse of Enron and other companies caused us to re-examine and realign our strategy to direct our attention to our utility markets. We have reduced trading to focus predominantly in markets where we have assets. We plan to obtain maximum value for our assets by selling excess output and procuring economical energy using commercial expertise gained from our extensive experience in the wholesale business.

Through our utility operations focus, we intend to be the energy and low cost generation provider of choice. We have ample generation to meet our customers' needs. We have a cost advantage resulting from AEP's long tradition of designing, building and operating efficient power plants and delivery networks. Our customers continue to show top quartile level of satisfaction. We provide safe and reliable sources of energy.

Our business provides a vital requirement of our economy and affords an opportunity for a fair return to our shareholders. Our business provides the opportunity for a predictable stream of cash flows and earnings, allowing us to pay a competitive dividend to investors.

We are addressing many challenges in our unregulated business. We have already substantially reduced our trading activities. We have written down the value of several investments to reflect deterioration in market conditions. We are evaluating our portfolio and plan to sell assets that are no longer core to our business strategy. We are also in discussion with our regulators to determine if the legal separation of certain operating company subsidiaries into regulated and unregulated segments can be avoided. We believe that the expected benefits from legal separation are no longer compelling. Transition rules for Michigan and Virginia do not require legal separation. Deregulation is no longer an expectation in the foreseeable future in the other states where we operate.

Our strategy for the core business of utility operations is to:

- Maintain moderate but steady earnings growth
- Maximize value of transmission assets and protect our revenue stream in an RTO membership environment
- Continue process improvement to maintain distribution service quality while, at the same time, further enhancing financial performance
- Optimize generation assets through increased availability and sale of excess capacity
- Manage the regulatory process to

maximize retention of earnings improvement while providing fair and reasonable rates to our customers

We remain very focused on credit quality and liquidity as discussed in greater detail later in this report.

We are committed to continually evaluating 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 sustainable shareholder value. Any investment dispositions could affect future results of operations, cash flows and possibly financial condition.

2002 Overview

2002 was a year of rapid and dramatic change for the energy industry, including AEP, as the wholesale energy market quickly shrank and many of its participants exited or significantly limited future trading activity. Investors lost confidence in corporate America and the economy stalled. Investors' demand for stability, predictable cash flows, earnings, and financial strength have replaced their demand for rapid growth.

Our wholesale business did not perform well. We had significant losses in options trading in the first half of the year and new investments performed well below our expectations.

We focused on financial strength by:

- Issuing approximately $1 billion in common stock and equity units
- Retiring debt of approximately $3 billion through the sale of two foreign retail utility companies in the U.K. (SEEBOARD) and Australia (CitiPower)
- Establishing a cash liquidity reserve of $1 billion at year-end

See the Financing Activity section for an overview of all changes to capital structure.

We also focused on:

- Implementing an enterprise-wide risk management system
- Completing a cost reduction initiative which we expect to result in sustainable net annual savings of more than $200 million beginning in 2003
- Eliminating or reducing future capital requirements associated with non-core assets

We have redirected our business strategy by:

- Scaling back trading activities to focus principally on supporting our core assets
- Selling our Texas retail business
- Proposing the sale of a significant portion of the Texas unregulated generation assets

Outlook for 2003

We remain focused on the fundamental earnings power of our utility operations, and we are committed to strengthening our balance sheet. Our strategy for achieving these goals is well planned:

- First, we will continue to identify opportunities to reduce our operations and maintenance expense.
- Second, we will find opportunities to reduce capital expenditures.
- Third, management recommended a 40% reduction in the common stock dividend beginning in the second quarter to a quarterly rate of $0.35 per share. This will result in annual cash savings of approximately $340 million and should improve our retained earnings as well as create free cash flow to improve liquidity and pay-down outstanding debt.
- Fourth, we plan to evaluate and, where appropriate, dispose of non-core assets. Proceeds from these sales will be used to reduce debt.
- Fifth, we will continue to evaluate the potential for issuing additional equity to further strengthen our balance sheet and maintain credit quality.

We remain committed to being a low cost provider of electricity, to serving our customers with excellence and to providing an attractive return to investors. We will therefore focus on producing the best possible results from our utility operations enhanced by a commercial group that ensures maximum value from our assets.

Although we aim for excellent results of operations there are challenges and certain risks. We discuss these matters in detail in the Notes to Consolidated Financial Statements and in this Management's Discussion and Analysis. We will work diligently to resolve these matters by finding workable solutions that balance the interests of our customers, our employees and our investors.

Results of Operations

In 2002 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, coal and other commodities
    - Coal mining, bulk commodity barging operations and other energy supply related businesses
- Energy Delivery
    - Domestic electricity transmission
    - Domestic electricity distribution
- Other Investments
    - Energy services

Net Income

Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect decreased $896 million or 98% to $21 million in 2002 from $917 million in 2001. The Company recognized impairments on under-performing assets and recorded losses in value of $854 million (net of tax) (see Note 13). The losses in the fourth quarter 2002 were generally caused by the extended decline in domestic and international wholesale energy markets and in telecommunications. In 2002 the Company's Net Loss was $519 million or a loss of $1.57 per share including the fourth quarter losses, losses on sales of SEEBOARD and CitiPower, and a loss for transitional goodwill impairment related to SEEBOARD and CitiPower that resulted from the adoption of SFAS 142 (see Note 3).

Net Income increased in 2001 to $971 million or $3.01 per share from $267 million or $0.83 per share in 2000. The increase of $704 million or $2.18 per share was due to the growth of AEP's wholesale marketing business, increased revenues and the controlling of our operating and maintenance costs in the energy delivery business, and declining capital costs. 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 were all contributing factors to the increase in 2001 earnings compared to 2000. The favorable effect on comparative Net Income of these 2000 charges was offset in part in 2001 by losses from Enron's bankruptcy and extraordinary losses for the effects of deregulation and a loss on reacquired debt.

Our wholesale business has been affected by a slowing economy. Wholesale energy margins and energy use by industrial customers declined in 2002 and 2001. Earnings from our wholesale business, which includes generation, increased in 2001 largely as a result of the successful return to service of the Cook Plant in June 2000 and by acquisitions of HPL and MEMCO.

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 in 2002 and 2001.

Capital costs decreased due primarily to interest paid to the IRS in 2000 on a COLI deduction disallowance and continuing declines in short-term market interest rate conditions since early 2001.

Volatility in energy commodities markets affects the fair values of all of our open trading and derivative contracts exposing AEP to market risk and causing our results of operations to be more volatile. See "Market

Risks" section for a discussion of the policies and procedures AEP uses to manage its exposure to market and other risks from trading activities.

Revenues Increase

AEP's total revenues increased 14% in 2002 and 15% in 2001. The following table shows the components of revenues:

	For The Year Ended December 31		
	2002	2001	2000
	(in millions)		
WHOLESALE:			
Residential	$3,713	$ 3,553	$ 3,511
Commercial	2,156	2,328	2,249
Industrial	1,903	2,388	2,444
Other Retail Customers	385	419	414
Electricity Marketing (net)	2,227	802	1,073
Unrealized MTM Income-Electric	136	210	38
Other	1,397	632	837
Less Transmission and Distribution Revenues Assigned to Energy Delivery*	(3,551)	(3,356)	(3,174)
Wholesale Electric	8,366	6,976	7,392
Gas Marketing (net)	3,021	2,274	310
Unrealized MTM Income (Loss)-Gas	(399)	47	132
Wholesale Gas	2,622	2,321	442
TOTAL WHOLESALE	10,988	9,297	7,834
DOMESTIC ELECTRICITY DELIVERY:			
Transmission	922	1,029	1,009
Distribution	2,629	2,327	2,165
TOTAL DOMESTIC ELECTRICITY DELIVERY	3,551	3,356	3,174
OTHER INVESTMENTS	16	114	105
TOTAL REVENUES	$14,555	$12,767	$11,113

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

The level of electricity 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 especially in the short-term market.

The increase in 2002 in wholesale revenues resulted from a 27% increase in trading volume associated with Wholesale Electricity which was offset by a continuing decrease in gross margins which began in the fourth quarter of 2001, and an increase in residential sales as a result of favorable weather conditions in the third quarter 2002. In addition Other wholesale electric revenues increased due to the mid-year 2001 acquisition of barging and coal mining operations as well as the recognition of revenues for generation projects completed for third parties. The increase in 2002 Wholesale Gas revenues resulted from a full year of HPL operations compared to a partial year from our acquisition date in July 2001, offset by a decrease in the results from financial trading and MTM unrealized losses. Other Investments decreased in 2002 due to the elimination of factoring of accounts receivable of an unaffiliated utility.

Prior to the third quarter of 2002, we recorded and reported upon settlement, sales under forward trading contracts as revenues and purchases under forward trading contracts as purchased energy expenses. Effective July 1, 2002, we reclassified such forward trading revenues and purchases on a net basis, as permitted by EITF 98-10 (see Note 1).

Kilowatthour sales to industrial customers decreased by 10% in 2002 and by 5% in 2001. This decrease was due to the economic slow down which began in late 2001. Sales to residential customers rose 5% due to weather related demand in 2002. The economic slow down reduced demand and wholesale prices especially in the latter part of 2001.

Operating Expenses Increase

Changes in the components of operating expenses were as follows:

	Increase (Decrease) From Previous Year			
	2002		2001	
	(in millions)			
	Amount	%	Amount	%
Fuel and Purchased Energy:				
Electricity	$ 959	43.7	$(1,275)	(36.7)
Gas	404	14.7	2,339	570.5
Maintenance and Other Operation	303	8.2	228	6.5
Non-recoverable Merger Costs	(11)	(52.4)	(182)	(89.7)
Asset Impairments	867	N.M.	-	-
Depreciation and Amortization	134	10.8	152	13.9
Taxes Other Than Income Taxes	51	7.6	(16)	(2.3)
Total	$2,707	25.6	$1,246	13.3

The increase in Fuel and Purchased Energy expense was primarily attributable to an increase in power generation. Net generation increased 6% for Eastern plants due to increased demand for electricity and a reduction in planned power plant maintenance outages for various plants as compared to 2001. 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. The increase in Gas expense was primarily due to a full year of HPL operations compared to a partial year from our acquisition date in July 2001.

The increase in Maintenance and Other Operation expense in 2002 is primarily due to recognizing a full year's expense for the businesses acquired during 2001 including MEMCO (a barging line), Quaker Coal, two power plants in the U.K. and HPL. In addition, increased administrative costs for the implementation of customer choice in Texas contributed to the increase. The increase was offset in part by a reduction in trading incentive compensation and the effect of planned boiler plant maintenance at various plants in 2001 and less refueling outages for STP in 2002 than 2001.

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.

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 and 2002 after the merger was consummated.

In 2002 AEP recorded pre-tax impairments of assets (including Goodwill) and investments totaling $1.4 billion (consisting of approximately, $866.6 million related to asset impairments, $321.1 million related to investment value losses, and $238.7 million related to discontinued operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, and other factors. These impairments exclude the transitional impairment loss from adoption of SFAS142 (see Note 2). The categories of impairments included:

	2002 Pre-Tax Estimated Loss (in millions)
Asset Impairments Held for Sale	$ 483.1
Asset Impairments Held and Used	651.4
Investment Value Losses	291.9
Total	$1,426.4

Additional market deterioration associated with our non-core wholesale investments, including our U.K. operations, could have an adverse impact on our future results of operations and cash flows. Significant long-term changes in external market conditions could lead to additional write-offs and potential divestitures of our wholesale investments, including, but not limited to, our U.K. operations.

The rise in Depreciation and Amortization expense in 2002 resulted from the amortization of Texas generation related Regulatory Assets that were securitized in early 2002, businesses acquired in 2001 and additional production plant placed into service.

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.

Taxes Other Than Income Taxes increased in 2002 due to a full year of state excise taxes which replaced the state gross receipts tax in Ohio and increased local franchise taxes in Texas partly offset by the effect of Texas one-time 2001 assessments and decreased gross Texas receipts taxes due to deregulation.

Interest, Preferred Stock Dividends, Minority Interest

The decrease in Interest in 2002 was primarily due to a reduction in short-term interest rates and lower outstanding balances of short-term debt and the refinancing of long-term debt at favorable interest rates offset in part by an increased amount of long-term debt outstanding.

Interest expense decreased 15% in 2001 due to the effect of interest paid to 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.

Minority Interest in Finance Subsidiary increased substantially in 2002 because the distributions to minority interest were in effect for the entire year. 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. The minority interest was only in effect during the last four months of 2001.

Other Income/Other Expenses

Other Income increased by $110 million or 33% in 2002 due to the sale of AEP'S retail electric providers in Texas and due to non-operational revenue (see Note 1). Other Expenses increased $134 million or 72% in 2002 due to non-operational expenses (see Note 1).

Other Income increased $240 million in 2001. This increase was primarily caused by an increase in equity earnings due to acquisitions of $63 million, a $73 million gain from the sale of a generating plant (see Note 1). Other Expenses increased by $110 million or 143% in 2001 due to costs to exit air transportation, fiber optic and Datapult businesses (see Note 1).

Income Taxes

The decrease in total Income Taxes in 2002 was due to a decrease in pre-tax book income offset by the tax effects of the sale of foreign operations.

Although pre-tax book income increased considerably in 2001, 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.

Extraordinary Losses and Cumulative Effect

The loss for transitional goodwill impairment related to SEEBOARD and CitiPower resulted from the adoption of SFAS 142 (see Notes 2 and 3) and has been reported as a Cumulative Effect of Accounting Change on January 1, 2002.

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.

Discontinued Operations

The operations shown below were discontinued or held for sale in 2002 (See

Note 12). Results of operations including impairment losses, net of tax, of these businesses have been reclassified:

Company	2002	2001	2000
		(in millions)	
SEEBOARD	$ 96	$ 88	$ 99
CitiPower	(123)	(6)	17
Pushan	(7)	4	7
Eastex	(156)	-	(1)
	$(190)	$ 86	$122

Reclassification

Balance sheet amounts have been restated to reflect our reclassification of certain assets and liabilities related to forward physical and financial transactions (see "Reclassification" discussion in Note 1). Based upon AEP's legal rights of offset, physical and financial contracts were netted in 2002 and 2001 amounts and financial contracts were netted in 2000 and 1999 amounts. Related assets and liabilities were not netted in 1998 amounts as the impact is not material.

Financial Condition

We measure our financial condition by the strength of the Consolidated Balance Sheets and the liquidity provided by cash flows and earnings.

Balance sheet capitalization ratios and cash flow ratios are principal determinants of our credit quality.

Credit Ratings

The rating agencies have been conducting credit reviews of AEP and our registrant subsidiaries. The agencies are also reviewing most companies in the energy sector due to issues which impact the entire industry, not only AEP and our subsidiaries.

In February 2003 Moody's Investors Service (Moody's) completed its review of AEP and our rated subsidiaries. The results of that review were downgrades of the following ratings for our unsecured debt: AEP to Baa3 from Baa2, APCo from Baa1 to Baa2, TCC from Baa1 to Baa2, PSO from A2 to Baa1, SWEPCo from A2 to Baa1. TNC, which had no senior unsecured notes outstanding at the time of the ratings action, had its mortgage bond debt downgraded from A2 to A3. AEP's commercial paper was also concurrently downgraded from P-2 to P-3. The completion of this review was a culmination of earlier ratings action in 2002 that had included a downgrade of AEP from Baa1 to Baa2 and the placement of five of our registrants on negative outlook. With the completion of the reviews, Moody's has placed AEP and its rated subsidiaries on stable outlook.

In February 2003 Standard & Poor's placed AEP's senior unsecured debt and commercial paper ratings on credit watch with negative implications, and did the same with our subsidiaries. S&P indicated that resolution regarding these actions would come within a short time.

In 2002 Fitch Ratings Service downgraded both PSO and SWEPCo from A to A- for the senior unsecured notes. Fitch has AEP and our subsidiaries on stable outlook and the commercial paper rating is stable at F-2.

Current ratings of our subsidiaries' first mortgage bonds are listed in the following table:

Company	Moody's	S&P	Fitch
APCo	Baa1	BBB+	A-
CSPCo	A3	BBB+	A
I&M	Baa1	BBB+	BBB+
KPCo	Baa1	BBB+	BBB+
OPCo	A3	BBB+	A-
PSO	A3	BBB+	A
SWEPCo	A3	BBB+	A
TCC	Baa1	BBB+	A
TNC	A3	BBB+	A

Current short-term ratings are as follows:

Company	Moody's	S&P	Fitch
AEP	P-3	A-2	F-2

The current ratings for senior unsecured debt are listed in the following table:

Company	Moody's	S&P	Fitch
AEP	Baa3	BBB+	BBB+
AEP Resources*	Baa3	BBB+	BBB+
APCo	Baa2	BBB+	BBB+
CSPCo	A3	BBB+	A-
I&M	Baa2	BBB+	BBB
KPCo	Baa2	BBB+	BBB
OPCo	A3	BBB+	BBB+
PSO	Baa1	BBB+	A-
SWEPCo	Baa1	BBB+	A-
TCC	Baa2	BBB+	A-
TNC	Baa1	BBB+	A-

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

AEP's common equity to total capitalization declined to 32% in 2002 from 36% in 2001 and 37% in 2000. Total capitalization includes long-term debt due within one year, equity unit senior notes, minority interest and short-term debt. Preferred stock at 1% remained unchanged. In 2002 long-term debt including equity unit senior notes and trust preferred securities increased from 43% to 50% while Short-term Debt decreased from 17% to 14% and Minority Interest in Finance Subsidiary remained unchanged at 3%. In 2001 Long-term Debt remained unchanged while Short-term Debt decreased from 20% to 17% and Minority Interest in Finance Subsidiary increased to 3%. In 2002, 2001 and 2000, AEP 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. Common stock was issued in 2002 for stock options exercised and under an equity offering (discussed in Financing Activity).

Liquidity

Liquidity, or access to cash, has become a more critical factor in determining the financial stability of the Company due to volatility in wholesale power markets and the potential limitations that credit rating downgrades place on a company's ability to raise capital. Management is committed to preserving an adequate liquidity position and addressing our financial needs in 2003.

As of December 31, 2002, we had an available liquidity position of $3.5 billion as illustrated in the table below:

Credit Facilities	(in millions)	Maturity
Commercial Paper Backup Lines of Credit	$2,500*	5/03
Commercial Paper Backup Lines of Credit	1,000	5/05
Corporate Separation Revolving Credit	1,725	4/03
Euro Revolving Credit Facilities	315	10/03
Total	5,540	
Cash		
Liquidity Reserve	1,000**	
Total Credit Facilities and Cash	6,540	
Less: Commercial Paper Outstanding	1,415	
Corporate Separation Loans	1,300	
Euro Revolving Credit Loans	305	
Total Available Liquidity	$3,520	

* Contains one year term-out provision.
** Unrestricted and excludes $213 million of operational cash on hand.

Our goal for 2003 is to use cash from operations to fund our capital expenditures, dividend payments and working capital requirements. Short-term debt is used as an interim bridge for timing differences in the need for cash or to fund debt maturities until permanent financing is arranged.

Short-term funding comes from the parent company's commercial paper program and revolving credit facilities. Proceeds are loaned to our subsidiaries through intercompany notes. We also operate a non-utility and utility money pool to minimize the AEP System's external short-term funding requirements and sell accounts receivable to provide liquidity for our domestic electric subsidiaries. The commercial paper program is backed by $3.5 billion in bank facilities of which $1 billion matures in May 2005. The remaining $2.5 billion matures in May 2003 and has a one-year term-out provision at our option. At December 31, 2002 approximately $1.4 billion of commercial paper was outstanding. A portion of the commercial paper balance is related to funding of debt maturities of the Ohio and Texas subsidiaries pending a permanent financing program. The Ohio and Texas subsidiaries issued $2,025 million of senior unsecured notes in February 2003 with maturity dates ranging from 2005 to 2033. The commercial paper balance outstanding decreased in early 2003 due to repayment with proceeds from these issuances.

AEP also has a $1.725 billion bank facility maturing in April 2003 that is available for debt refinancing. At December 31, 2002, $1.3 billion was outstanding under that facility. With the issuance of the permanent financing for the Ohio and Texas subsidiaries mentioned above, this facility was repaid and cancelled in February 2003.

We also have revolving credit facilities in place for 300 million Euros to support the wholesale business in Europe. At December 31, 2002, the majority of these facilities were drawn.

AEP also maintains a minimum $300 million cash liquidity reserve fund to support its marketing operations in the U.S. and keeps additional cash on hand as market conditions change. At December 31, 2002, we had $1 billion of cash available for liquidity.

On December 6, 2002, we closed a 364-day, $425 million facility and used it to partially repay the maturing interim financing for the U.K. generation plants (FFF). The facility was secured by a pledge of the shares of AEP companies in the FFF ownership chain and guaranteed by the parent company. A portion ($213 million) of the facility is due in May 2003. The remainder of the FFF interim financing was repaid using a combination of existing funds and draws against the two Euro revolving credit facilities.
In total, we had approximately $6.5 billion in liquidity sources of which $3.5 billion were unused and available at December 31, 2002.

During 2002, cash flow from operations was approximately $1.7 billion, including $21 million from Net Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect, approximately $1.3 billion from depreciation, amortization, deferred taxes, and deferred investment tax credits, approximately $1.1 billion associated with asset, investment value and other impairments, offset by additional working capital requirements of approximately $700 million. These additional working capital requirements reflect the one time impact of the discontinuance of the sale of accounts receivable for Texas companies and billing delays related to the transition to customer choice in Texas, higher margin requirements for gas trading, seasonal fuel inventory growth, and other miscellaneous items. Construction expenditures were $1.7 billion including major expenditures for emission control technology on several coal-fired generating units (see discussion in Note 9). Dividends on common stock were $793 million. Cash from operations, proceeds from the sale of SEEBOARD, CitiPower and the Texas REPs and the issuance of common stock, common equity units, 15-year notes for a wind generation project and transition funding bonds provided funds to reduce debt, fund construction and pay dividends.

During 2001, AEP's cash flow from operations was $2.8 billion, including $885 million from Net Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect and $1.4 billion from depreciation, amortization, deferred taxes and deferred investment tax credits. Capital expenditures including acquisitions were $3.9 billion and dividends on common stock were $773 million. Cash from operations less dividends on common stock financed 51% of capital expenditures.

During 2001, the proceeds of AEP's $1.25 billion global notes issuance and proceeds from the sale of a U.K. 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. Asset purchases included HPL, coal mines, a barge line, a wind generating facility and two coal-fired generating plants in the U.K. These acquisitions accounted for the increase in total debt during 2001. Long-term funding arrangements for specific assets are often complex and typically not completed until after the acquisition.

The loss for 2002 resulted in a negative dividend payout ratio of 153% reflecting the losses on sale and impairments of assets. 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 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, long-term debt, sale-leasebacks and leasing arrangements. The domestic electric subsidiaries generally issue short-term debt to provide for interim financing of capital expenditures that exceed internally generated funds and periodically reduce their outstanding short-term debt through issuances of long-term debt and additional capital contributions from their parent company.

Our revolving credit agreements include covenants that require us to perform certain actions, including maintaining specified financial ratios. Non-performance of these covenants may result in an event of default under these credit agreements. At December 31, 2002, we complied with the covenants contained in these credit agreements. In addition, a default under any other agreement or instrument relating to our debt outstanding in excess of $50 million is an event of default under these credit agreements. An event of default under these credit agreements would cause all amounts outstanding thereunder to be immediately payable.

Financing Activity

Common Stock

In June 2002 AEP issued 16 million shares of common stock at $40.90 per share through an equity offering and received net proceeds of $634 million. Proceeds from the sale of equity units and common stock were used to pay down short-term debt and establish a cash liquidity reserve fund.

Equity Units

In June 2002, AEP issued 6.9 million equity units at $50 per unit ($345 million). See Note 27 for additional information.

Debt

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

In April 2002 AEP closed on a bridge loan facility consisting of a $1.125 million 364-day revolving credit facility and a $600 million 364-day term loan facility to prepare for corporate separation. At year-end, $600 million was borrowed under the term loan facility and $700 million was borrowed under the revolving credit facility. Those amounts were repaid and the facility terminated when bonds were issued by CSPCo, OPCo, TCC and TNC in February 2003.

In February 2003 CSPCo issued $250 million of unsecured senior notes due 2013 at a coupon of 5.50% and $250 million of unsecured senior notes due 2033 at a coupon of 6.60%. OPCo issued $250 million of unsecured senior notes due 2013 at a coupon of 5.50% and $250 million of unsecured senior notes due 2033 at a coupon of 6.60%. TCC issued $100 million of unsecured senior notes due 2005 at a variable rate, $150 million of unsecured senior notes due 2005 at a coupon of 3.0%, $275 million of unsecured senior notes due 2013 at a coupon of 5.50% and $275 million of unsecured senior notes due 2033 at a coupon of 6.65%. TNC issued $225 million of unsecured senior notes due 2013 at a coupon of 5.50%. The use of proceeds from the above bonds was repayment of the bridge loan facility mentioned above, repayment of short-term debt, and for general corporate purposes.

In 2002 the following issuances were completed by the subsidiaries of AEP:

Company	Type of Debt	Principal Amount (in millions)	Interest Rate	Due Date
APCo	Senior Unsecured Notes	$450	4.80%	2005
APCo	Senior Unsecured Notes	200	4.32%*	2007
I&M	Installment Purchase Contracts	50	4.90%	2025
I&M	Senior Unsecured Notes	150	6.0%	2032
I&M	Senior Unsecured Notes	100	6 3/8%	2012
KPCo	Senior Unsecured Notes	125	5.50%	2007
KPCo	Senior Unsecured Notes	80	4.32%*	2007
KPCo	Senior Unsecured Notes	70	4.37%*	2007
PSO	Senior Unsecured Notes	200	6.00%	2032
SWEPCo	Senior Unsecured Notes	200	4.50%	2005
Other Subsidiaries	Notes Payable	121	6.20%-6.60%	2017
Other Subsidiaries	Revolving Credit	305	Variable	2003

*Interest rate payable by subsidiary in U.S. dollars. While these companies do not have an Australian rate obligation, there is an underlying interest rate to Australian investors in Australian dollars of either 6% or a variable rate.

The subsidiaries also redeemed approximately $2 billion of long-term debt in 2002.

AEP uses money pools to meet the short-term borrowings for the majority of its subsidiaries In addition, AEP also funds the short-term debt requirements of other subsidiaries that are not included in the money pool. As of December 31, 2002, AEP had credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2002, AEP had $1.4 billion outstanding in short-term borrowings subject to these credit facilities.

AEP Credit purchases, without recourse, the accounts receivable of most of the domestic utility operating companies. AEP Credit's financing for the purchase of receivables changed in December 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 Consolidated Balance Sheets. At December 31, 2002, AEP Credit had $454 million sold under this agreement. See Note 23 for further discussion.

Off-balance Sheet Arrangements

AEP enters into off-balance sheet arrangements for various reasons ranging from accelerating cash collections, reducing operational expense to spreading risk of loss to third parties. The following identifies AEP's significant off-balance sheet arrangements:

Power Generation Facility

AEP has entered into agreements with Katco Funding L.P. (Katco) an unrelated unconsolidated special purpose entity. Katco has an aggregate financing commitment of $525 million and a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from a syndicate of banks. Katco was formed to develop, construct, finance and lease a power generation facility to AEP. Katco will own the power generation facility and lease it to AEP after construction is completed. The lease will be accounted for as an operating lease (see Note 22), therefore neither the facility nor the related obligations are reported on AEP's balance sheet. Payments under the operating lease are expected to commence in the first quarter of 2004. AEP will in turn sublease the facility to Dow Chemical Company (DOW), which will use the energy produced by the facility and sell excess energy. AEP has agreed to purchase the excess energy from DOW for resale. The use of Katco allows AEP to limit its risk associated with the power generation facility once the construction phase has been completed.

AEP, is the construction agent for Katco, and is responsible for completing construction by December 31, 2003, subject to unforeseen events beyond AEP's control.

In the event the project is terminated before completion of construction, AEP has the option to either purchase the facility for 100% of project costs or terminate the project and make a payment to Katco for 89.9% of project costs.

The operating lease between Katco and AEP commences on the commercial operation date of the facility and continues until November 2006. The lease contains extension options subject to the approval of Katco, and if all extension options were exercised, the total term of the lease would be 30 years. AEP's lease payments to Katco are sufficient for Katco to make required debt payments and provide a return to the investors of Katco. At the end of each lease term, AEP may renew the lease at fair market value subject to Katco's approval, purchase the facility at its original construction cost, or sell the facility, on behalf of Katco, to an independent third party. If the facility is sold and the proceeds from the sale are insufficient to repay Katco, AEP may be required to make a payment to Katco for the difference between the proceeds from the sale and the obligations of Katco, up to 82% of the project's cost. AEP has guaranteed a portion of the obligations of its subsidiaries to Katco during the construction and post-construction periods.

As of December 31, 2002, project costs subject to these agreements totaled $360 million, and total costs for the completed facility are expected to be approximately $510 million. For the 30–year extended lease term, the lease rental 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 during the initial term calculated using the indexed LIBOR rate (1.38% at December 31, 2002). The Power Generation Facility collateralizes the debt obligation of Katco. AEP's maximum exposure to loss as a result of its involvement with Katco is 100% during the construction phase and up to 82% once the construction is completed. Maximum loss is deemed to be remote due to the collateralization.

It is reasonably possible that AEP will consolidate Katco in the third quarter of 2003, as a result of the issuance of FASB Interpretation No. 46 "Consolidation of Variable Interest Entities" (FIN 46). Upon consolidation, AEP would record the assets, liabilities, depreciation expense, minority interest and debt interest expense. AEP would eliminate operating lease expense. The sublease to DOW would not be affected by this consolidation.

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

Minority Interest in Finance Subsidiary

In August 2001 AEP formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis). SubOne is a wholly owned consolidated subsidiary of AEP that was capitalized with the assets of Houston Pipe Line Company, Louisiana Interstate Gas Company (AEP subsidiaries) and $321.4 million of AEP Energy Services Gas Holding Company (AEP Gas Holding is an AEP subsidiary and parent of SubOne) preferred stock, that is convertible into AEP common stock at market price on a dollar-for-dollar basis. Caddis was capitalized with $2 million cash and a subscription agreement that represents an unconditional obligation to fund $83 million from SubOne and $750 million from Steelhead Investors LLC ("Steelhead" - non-controlling preferred member interest). As managing member, SubOne consolidates Caddis. Steelhead is an unconsolidated special purpose entity and has a capital structure of $750 million of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from a syndicate of banks. The use of Steelhead allows AEP to limit its risk associated with Houston Pipe Line Company and Louisiana Intrastate Gas Company.

Under the provisions of the Caddis formation agreements, Steelhead receives a quarterly preferred return equal to an adjusted floating reference rate (4.784% and 4.413% for the quarters ended December 31, 2002 and 2001, respectively). Caddis has the right to redeem Steelhead's interest at any time.

The $750 million invested in Caddis by Steelhead was loaned to SubOne. This intercompany loan to SubOne is due August 2006, and is supported by the natural gas pipeline assets of SubOne, a cash reserve fund of SubOne and SubOne's $321.4 million of preferred stock in AEP Gas Holding. The preferred stock is convertible into AEP common stock upon the occurrence of certain events including AEP's stock price closing below $18.75 for ten consecutive trading days. AEP can elect not to have the transaction supported by such preferred stock if SubOne were to reduce its loan with Caddis by $225 million. The credit agreement between Caddis and SubOne contains covenants that restrict certain incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. The credit agreement also contains covenants that impose minimum financial ratios. Non-performance of these covenants may result in an event of default under the credit agreement. Through December 31, 2002, we have complied with the covenants contained in the credit agreement. In addition, a default under any other agreement or instrument relating to AEP and certain subsidiaries' debt outstanding in excess of $50 million is an event of default under the credit agreement.

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

Steelhead has certain rights as a preferred member in 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 AEP Gas Holding preferred stock into AEP common stock. If Steelhead exercised its rights to force Caddis to liquidate under these conditions, then AEP would evaluate whether to refinance at that time or relinquish the assets that support the intercompany loan to Caddis. Liquidation of Caddis could negatively impact AEP's liquidity.

Caddis and SubOne 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 SubOne are consolidated with AEP for financial reporting purposes. Steelhead's investment in Caddis and payments made to Steelhead from Caddis are currently reported on AEP's income statement and balance sheet as Minority Interest in Finance Subsidiary.

AEP's maximum exposure to loss as a result of its involvement with Steelhead is $321.4 million of preferred stock, $83 million under the subscription agreement to Caddis for any losses incurred by Caddis and the cash reserve fund balance of $34 million (as of December 31, 2002) due Caddis for default under the intercompany loan agreement. AEP can reduce its maximum exposure related to the preferred stock by a reduction of $225 million of the intercompany loan.

As of December 31, 2002, we are continuing to review the application of FIN 46 as it relates to the Steelhead transaction.

<u>AEP Credit</u>

AEP Credit entered into a sale of receivables agreement with a group of banks and commercial paper conduits. Under the sale of receivables agreement, which expires May 28, 2003, AEP Credit sells an interest in the receivables it acquires 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 and allowing AEP Credit to repay any debt obligations. 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. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

At December 31, 2002, the sale of receivables agreement provided the banks and commercial paper conduits would purchase a maximum of $600 million of receivables from AEP Credit, of which $454 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. The commitment's new term under the sale of receivables agreement will remain at $600 million until May 28, 2003. 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 receivables less an allowance for anticipated uncollectible accounts.

See Note 23 "Lines of Credit and Sale of Receivables" for further disclosure.

Gavin Plant's flue gas desulfurization system (Gavin Scrubber)

OPCo has entered into an agreement with JMG Funding LLP (JMG) an unrelated unconsolidated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from pollution control bonds and other bonds. JMG owns the Gavin Scrubber and leases it to OPCo. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. Payments under the operating lease are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. Neither OPCo nor AEP has an ownership interest in JMG and does not guarantee JMG's debt.

At any time during the lease, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber. The initial 15-year lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.

The use of JMG allows AEP to enter into an operating lease while keeping the tax benefits otherwise associated with a capital lease. As of December 31, 2002, unless the structure of this arrangement is changed, it is reasonably possible that AEP will consolidate JMG in the third quarter of 2003 as a result of the issuance of FIN 46. Upon consolidation, AEP would record the assets, liabilities, depreciation expense, minority interest and debt interest expense of JMG. AEP would eliminate operating lease expense. AEP's maximum exposure to loss as a result of its involvement with JMG is approximately $560 million of outstanding debt and equity of JMG as of December 31, 2002.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee) an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. AEGCo, I&M nor AEP has ownership interest in the Owner Trustee and do not guarantee its debt.

Summary Obligations Information

The contractual obligations of AEP include amounts reported on the Consolidated Balance Sheets and other obligations disclosed in the footnotes. The following table summarizes AEP's contractual cash obligations at December 31, 2002:

	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	$1,633	$1,817	$2,316	$ 4,354	$10,120
Short-term Debt	3,164	-	-	-	3,164
Equity Unit Senior Notes	-	-	376	-	376
Trust Preferred Securities	-	-	-	321	321
Minority Interest In Finance Subsidiary (a)	-	-	759	-	759
Preferred Stock Subject to Mandatory Redemption	-	-	-	84	84
Capital Lease Obligations	70	90	50	18	228
Unconditional Purchase Obligations (b)	1,405	1,810	989	1,513	5,717
Noncancellable Operating Leases	305	523	479	2,462	3,769
Total Contractual Cash Obligations	$6,577	$4,240	$4,969	$ 8,752	$24,538

(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.

The SPE's, described under "Off-Balance Sheet Arrangements" above, 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 Scrubbers, the permanent financing of HPL, and the sale of accounts receivable all use SPE's. Neither AEP nor any AEP related parties have an ownership interest in the SPE. AEP does not guarantee the debt of these entities. These SPEs are not consolidated in AEP's financial statements in accordance with GAAP. As a result, neither the assets nor the debt of the SPE are included on the Consolidated Balance Sheets. The future cash obligations payable to the SPEs are included in the above table.

In addition to the amounts disclosed in the contractual cash obligations table above, AEP and our subsidiaries make 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, 2002 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 (a)	$ 125	$ 1	$ -	$ 40	$ 166
Guarantees of the Performance of Outside Parties (b)	13	17	325	137	492
Guarantees of our Performance	1,159	2	82	9	1,252
Construction of Generating and Transmission Facilities for Third Parties (c)	671	83	47	67	868
Other Commercial Commitments (d)	14	53	11	-	78
Total Commercial Commitments	$1,982	$156	$465	$253	$2,856

(a) AEP has standby letters of credit to third parties. These letters of credit cover gas and electricity trading contracts, various construction contracts and credit enhancement for issued bonds. All of these letters of credit were issued at a subsidiary level of AEP in the subsidiaries' ordinary course of business. The maximum future payments of these letters of credit are $166 million with maturities ranging from January 2003 to December 2007. There is no liability recorded for these letters of credit in accordance with FIN 45. Since AEP is the parent to all these subsidiaries, it holds all assets of the subsidiary as collateral. There is no recourse to third parties in the event these letters of credit are drawn.
(b) These amounts are the balances drawn, not the maximum guarantee disclosed in Note 10.
(c) 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.
(d) Represents estimated future payments for power to be generated at facilities under construction.

With the exceptions of SWEPCo's guarantee of an unaffiliated mine operator's obligations (payable upon their default) of $148 million at December 31, 2002, and OPCo's obligations under a power purchase agreement of $14 million each year in 2003 through 2005, the obligations in the above table are commitments of AEP and its non-registrant subsidiaries.

OPCo has entered into a 30-year power purchase agreement for electricity produced by an unaffiliated entity's three-unit natural gas fired plant. The plant was completed in 2002 and the agreement will terminate in 2032. Under the terms of the agreement, OPCo has the option to run the plant until December 31, 2005 taking 100% of the power generated and making monthly capacity payments. The capacity payments are fixed through December 2005 at $1.2 million per month. 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 are included in the Other Commercial Commitments table shown above.

Expenditures for domestic electric utility construction are estimated to be $4 billion for the next three years. Approximately 90% of those construction expenditures are expected to be financed by internally generated funds.

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. Certificates have been issued by both the WVPSC and the Virginia SCC authorizing construction and operation of the line. On December 31, 2002, the United States Forest Service issued a final environmental impact statement and record of decision to allow the use of federal lands in the Jefferson National Forest for construction of a portion of the line. We expect additional state and federal permits to be issued in the first half of 2003. Through December 31, 2002 we had invested approximately $51 million in this effort. The line is estimated to cost $287 million including amounts spent to date with completion in 2006. If the required permits are not obtained and the line is not constructed, the $51 million investment would be written off adversely affecting future results of operations and cash flows.

Pension Plans

The Company maintains qualified defined benefit pension plans (Qualified Plans), which cover substantially all non-union and certain union associates and unfunded excess plans to provide benefits in excess of amounts permitted to be paid under the provisions of the tax law to participants in the Qualified Plans. Additionally, the Company has entered into individual retirement agreements with certain current and retired executives that provide additional retirement benefits.

Our pension income for all pension plans approximated $69 million and $44 million for the years ended December 31, 2001 and December 31, 2002, respectively, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on our Qualified Plans' assets of 9%. In developing our expected long-term rate of return assumption, we evaluated input from our actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Projected returns by such actuaries and consultants are based on broad equity and bond indices. We also considered historical returns of the investment markets as well as our 10-year average return (for the period ended 2002) of 8.8%. We anticipate that our investment managers will continue to generate long-term returns of at least 9.0%. Our expected long-term rate of return on the Qualified Plans' assets is based on an asset allocation assumption of 70% with equity managers, with an expected long-term rate of return of 10.5%, and 28% with fixed income managers, with an expected long-term rate of return of 6%, and 2% in cash and short term investments with an expected rate of return of 3%. Because of market fluctuation, our actual asset allocation as of December 31, 2002 was 67% with equity managers and 32% with fixed income managers and 1% in cash. We believe, however, that our long-term asset allocation on average will approximate 70% with equity managers, 28% with fixed income managers and the remaining 2% in cash. We regularly review our actual asset allocation and periodically rebalance our investments to our targeted allocation when considered appropriate. We continue to believe that 9.0% is a reasonable long-term rate of return on our Qualified Plans' assets, despite the recent market downturn in which our Qualified Plans' assets had a loss of 11.2% for the twelve months ended December 31, 2002. We will continue to evaluate our actuarial assumptions, including our expected rate of return, at least annually, and will adjust as necessary.

We base our determination of pension expense or income on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2002 we had cumulative losses of approximately $879 million which remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses result in increases in our future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The discount rate that we utilize for determining future pension obligations is based on a review of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rate determined on this basis has decreased from 7.25% at December 31, 2001 to 6.75% at December 31, 2002. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on our Qualified Plans' assets of 9.0%, a discount rate of 6.75% and various other assumptions, we estimate that our pension expense for all pension plans will approximate $2 million, $46 million and $97 million in 2003, 2004 and 2005, respectively. Future actual pension expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in our pension plans.

Lowering the expected long-term rate of return on our Qualified Plans, assets by .5% (from 9.0% to 8.5%) would have reduced our pension income for 2002 by approximately $19 million. Lowering the discount rate by 0.5% would have reduced our pension income for 2002 by approximately $8 million.

The value of our Qualified Plans' assets has decreased from $3.438 billion at December 31, 2001 to $2.795 billion at December 31, 2002. The Qualified Plans paid out $272 million in benefits to plan participants during 2002 (nonqualified plans paid out $6 million in benefits). The investment returns and declining discount rates have changed the status of our Qualified Plans from overfunded (plan assets in excess of projected benefit obligations) by $146 million at December 31, 2001 to an underfunded position (plan assets are less than projected benefit obligations) of $788 million at December 31, 2002. Due to the Qualified Plans currently being underfunded, the Company recorded a charge to Other Comprehensive Income (OCI) of $585 million, and a Deferred Income Tax Asset of $315 million, offset by a Minimum Pension Liability of $662 million and a reduction to prepaid costs and intangible assets of $238 million. The charge to OCI does not affect earnings or cash flow. AEP is in full compliance with all regulations governing such plans including all Employee Retirement Income Security Act of 1974 laws. Because of the recent reductions in the funded status of our Qualified Plans, we expect to make cash contributions to our Qualified Plans of approximately $66 million in 2003 increasing to approximately $108 million per year by 2005.

Critical Accounting Policies

In the ordinary course of business, AEP has made a number of estimates and assumptions relating to the reporting of results of operations and financial condition in the preparation of its consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ significantly from those estimates under different assumptions and conditions. AEP believes that the following discussion addresses the most critical accounting policies, which are those that are most important to the portrayal of the financial condition and results and require management's most difficult, subjective and complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

<u>Revenue Recognition</u>

Regulatory Accounting – The consolidated financial statements of AEP and the financial statements of electric operating subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo) 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, regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities are also recorded to provide for refunds to customers that have not yet been made.

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, issuance of 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 earnings. A write-off of regulatory assets may also reduce future cash flows since there may be no recovery through regulated rates.

Traditional Electricity Supply and Delivery Activities - Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The revenues are recognized in our Consolidated Statements of Operations when the energy is delivered to the customer and include unbilled as well as billed amounts. In general, expenses are recorded when purchased electricity is received and when expenses are incurred.

Domestic Gas Pipeline and Storage Activities – Revenues are recognized from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided. Transportation and storage revenues also include the accrual of earned, but unbilled and/or not yet metered gas.

Substantially all of the forward gas purchase and sale contracts, excluding wellhead purchases of natural gas, swaps and options for the domestic pipeline operations, qualify as derivative financial instruments as defined by SFAS 133. Accordingly, net gains and losses resulting from revaluation of these contracts to fair value during the period are recognized currently in the consolidated results of operations, appropriately discounted and net of applicable credit and liquidity reserves.

Energy Marketing and Trading Activities –In 2000, 2001 and throughout the majority of 2002, AEP engaged in broad non-regulated wholesale electricity, natural gas and other commodity marketing and trading transactions (trading activities). AEP's trading activities involved the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options and over-the-counter options and swaps. We used the mark-to-market method of accounting for trading activities as required by EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10). Under the mark-to-market method of accounting, gains and losses from settlements of forward trading contracts are recorded net in revenues. For energy contracts not yet settled, whether physical or financial, changes in fair value are recorded net as revenues. Such fair value changes are referred to as unrealized gains and losses from mark-to-market valuations. When positions are settled and gains and losses are realized, the previously recorded unrealized gains and losses from mark-to-market valuations are reversed. Unrealized mark-to-market gains and losses are included in the Consolidated Balance Sheets as "Energy Trading and Derivative Contracts." In October 2002, management announced plans to focus on wholesale markets where we own assets.

The majority of trading activities represent physical forward contracts that are typically settled by entering into offsetting contracts. An example of our energy trading activities is when, in January, we enter into a forward sales contract to deliver energy 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 a gain or loss in cash and reverse to revenues the previously recorded cumulative 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 for a sales contract and the realized cost for a purchase contract are included on a net basis in revenues with the prior change in unrealized fair value reversed out of 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 energy 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. Mark-to-market accounting for these contracts from this point forward will have no further impact on operating results but has an offsetting and equal effect on trading contract assets and liabilities. 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 MTM accounting.

For AEP, the trading of energy 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 the prior cumulative unrealized net gain or loss.

The fair values of open short-term trading contracts are based on exchange prices and broker quotes. We mark-to-market open long-term trading contracts based primarily on valuation models that 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 the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due to 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. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time contracts settle. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with AEP's approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

AEP applies MTM accounting to 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.

Volatility in energy commodity markets affects the fair values of all of our open trading and derivative contracts exposing us to market risk and causing our results of operations to be subject to volatility. See Note 17, "Risk Management, Financial Instruments and Derivatives" for a discussion of the policies and procedures used to manage our exposure to market and other risks from trading activities.

Given the previously discussed reduction in AEP's trading activities, the impact of mark-to-market accounting on our financial statements is expected to decline in future periods.

<u>Long-Lived Assets</u>

Long-lived assets, including fixed assets and intangibles, are evaluated periodically for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. If the sum of the undiscounted cash flows is less than the carrying value, we recognize an impairment loss, measured as the amount by which the carrying value exceeds the fair value of the asset. The estimate of cash flow is based upon, among other things, certain assumptions about expected future operating performance. Our estimates of undiscounted cash flow may differ from actual cash flow due to, among other things, technological changes, economic conditions, changes to our business model or changes in our operating performance.

<u>Pension Benefits</u>

We sponsor pension and other retirement plans in various forms covering substantially all employees who meet eligibility requirements. Several statistical and other factors which attempt to anticipate future events are used in calculating the expense and liability related to the plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by management, within certain guidelines. In addition, our actuarial consultants also use subjective factors such as withdrawal and mortality rates to estimate these factors. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded.

New Accounting Pronouncements

See Note 1 to the consolidated financial statements for a discussion of significant accounting policies and new accounting pronouncements.

Market Risks

As a major power producer and marketer 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 have been 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 Executive Committee and administered by a Chief Risk Officer. The Risk Executive 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. of 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 in the trading portfolio. 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, 2002 a near term typical change in commodity prices is not expected to have a material effect on our consolidated 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,					
	2002			2001		
	High	Average	Low	High	Average	Low
	(in millions)					
AEP	$24	$12	$4	$28	$14	$5

After the October announcement of our strategy to reduce trading activity, the related VaRs were substantially reduced. The average AEP trading VaR for the fourth quarter 2002 was $7 million as compared to $13 million for fourth quarter 2001. In 2003 we will continue to adjust our VaR limit structure commensurate with our anticipated level of trading activity.

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 $527 million at December 31, 2002 and $673 million at December 31, 2001. 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 consolidated results of operations or 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 Michigan and West Virginia or capped in Indiana. 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 other commodities and as a result we are 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 be within the limits unless specifically approved by the Risk Executive 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 certain power trading 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.

Credit Risk

AEP limits credit risk by extending unsecured credit to entities based on internal ratings. In addition, AEP uses Moody's Investors 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 counterparties depending upon credit quality 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 exposure with any one counterparty is not material to our financial condition at December 31, 2002. At December 31, 2002 approximately 7% of our exposure was below investment grade as expressed in terms of net MTM assets. Net MTM assets represents the aggregate difference between the forward market price for the remaining term of the contract and the contractual price per counterparty. The following table approximates counterparty credit quality and exposure for AEP based on netting across AEP entities, commodities and instruments.

Counterparty Credit Quality: December 31, 2002	Futures, Forward and Swap Contracts	Options	Total
	(in millions)		
AAA/Exchanges	$ 26	$ 2	$ 28
AA	307	33	340
A	448	26	474
BBB	700	101	801
Below Investment Grade	107	11	118
Total	$ 1,588	$ 173	$1,761

The counterparty credit quality and exposure for the registrant subsidiaries is generally consistent with that of AEP.

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, 2002 and 2001 were $109 million and $55 million. These margin accounts are restricted and therefore are not included in Cash and Cash Equivalents on the Consolidated Balance Sheets. 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 in accordance with generally accepted accounting principles and include the net change in mark-to-market amounts on a net discounted basis in revenues. The marking-to-market of open trading contracts contributed an unrealized $180 million to revenues in 2002. The mark-to-market 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 internally developed valuation models. The gross value is present valued and reduced by appropriate valuation adjustments for counterparty credit risks and liquidity risk to arrive at fair value. 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 liquid portion of these curves are validated on a regular basis by the middle-office through the market data. Illiquid portions of the curves are validated through a review of the underlying market assumptions and variables for consistency and reasonableness. The end of the month liquidity reserve is based on the difference in price between the price curve and the bid price if we have a long position and the price curve and the ask price if we have a short position. This provides for a more accurate valuation of energy contracts.

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 prices, at the time of settlement, do not correlate with the Company developed price models.

The effect on the Consolidated Statements of Operations of marking to market open electricity trading contracts in the Company's regulated jurisdictions, is deferred as regulatory assets (losses) or liabilities (gains) 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,		
	2002	2001	2000
	(in millions)		
Revenues (including mark- to-market adjustment)	$14,555	$12,767	$11,113
Fuel and Purchased Energy Expense	6,307	4,944	3,880
Net Revenues	$ 8,248	$ 7,823	$ 7,233
Mark-to-Market Revenues	$180	$207	$187
Percentage of Net Revenues Represented by Mark-to-Market On Open Trading Positions	2%	3%	3%

The following tables analyze the changes in fair values of trading assets and liabilities. The first table "Net Fair Value of Mark-to-Market Energy Trading and Derivative Contracts" shows how the net fair value of energy trading contracts was derived from the amounts included in the Consolidated Balance Sheets line item "Energy Trading and Derivative Contracts." The next table "Mark-to-Market Energy Trading and Derivative 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 and related derivatives at December 31, 2001 of $448 million to December 31, 2002 of $250 million. Contracts realized/settled during the period include both sales and purchase contracts. The third table "Mark-to-Market Energy Trading and Derivative 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 Mark-to-Market Energy Trading and Derivative Contracts

	December 31 2002	December 31 2001
	(in millions)	
Energy Trading and Derivative Contracts:		
Current Asset	$1,046	$ 2,125
Long-term Asset	824	795
Current Liability	(1,147)	(1,877)
Long-term Liability	(484)	(603)
Net Fair Value of Energy Trading and Derivative Contracts	239	440
Non-trading related derivative liabilities	11*	-
Assets held for sale (CitiPower)	-	8
Net Fair Value of Energy Trading and Derivative Contracts	$ 250	$ 448

* Excludes $6 million Loss recorded in an equity investment.

The above net fair value of energy trading and derivative contracts includes $180 million at December 31, 2002, in unrealized mark-to-market gains that are recognized in the Consolidated Statements of Operations at December 31, 2002.

Mark-to-Market Energy Trading and Derivative Contracts

	Total (in millions)	
Net Fair Value of Energy Trading and Derivative Contracts at December 31, 2001	$ 448	
(Gain) Loss from Contracts Realized/Settled During the Period	(182)	(a)
Fair Value of New Open Contracts When Entered Into During the Period	68	(b)
Net Option Premiums Paid/(Received)	(130)	(c)
Change in fair value due to Methodology Changes	1	(d)
Change in Market Value of Energy Trading Contracts Allocated to Regulated Jurisdictions	(2)	(e)
Changes in Market Value of Contracts	47	(f)
Net Fair Value of Energy Trading and Derivative Contracts at December 31, 2002	$ 250	

(a) (Gain) Loss from Contracts Realized/Settled During the Period" include realized gains from energy trading contracts and related derivatives that settled during 2002 that were entered into prior to 2002.
(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 2002. 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) Net Option Premiums Paid/(Received)" reflects the net option premiums paid/(received) as they relate to unexercised and unexpired option contracts that were entered into in 2002.
(d) The Company changed the discount rate applied to its trading portfolio from BBB+ Utility to LIBOR in the second quarter which increased fair value by $10 million. In addition, the Company changed its methodology in valuing a spread option model so as to more accurately reflect the exercising of power transactions at optimal prices which reduced fair value by $9 million.
(e) "Change in Market Value of Energy Trading Contracts Allocated to Regulated Jurisdictions" relates to the net gains of those contracts that are not reflected in the Consolidated Statements of Operations. These net gains are recorded as regulatory liabilities for those subsidiaries that operate in regulated jurisdictions.
(f) "Changes 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.

Mark-to-Market Energy Trading and Derivative Contract Maturities

AEP Consolidated Source of Fair Value	Fair Value of Contracts at December 31, 2002 Maturities (in millions) Less than 1 year	1-3 years	4-5 years	In Excess Of 5 years	Total Fair Value
Prices Actively Quoted (a)	$(32)	$ 69	$ -	$ -	$ 37
Prices Provided by Other External Sources (b)	24	189	11	-	224
Prices Based on Models and Other Valuation Methods (c)	(84)	13	36	24	(11)
Total	$(92)	$271	$47	$24	$ 250

(a) "Prices Actively Quoted" represents the Company's exchange traded futures, options and euro dollar positions.
(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. 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 17, "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, operating and maintaining utility plant assets. 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.

Industry Restructuring

Four of the eleven state retail jurisdictions (Michigan, Ohio, Texas and Virginia) in which our domestic electric utility companies operate have implemented retail restructuring legislation. Three other states (Arkansas, Oklahoma and West Virginia) initially adopted retail restructuring legislation, but have since either delayed the implementation of that legislation, or repealed the legislation (Arkansas). In general, retail restructuring legislation provides for a transition from cost-based rate 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 have discontinued the application of SFAS 71, regulatory accounting for the generation business. AEP has not discontinued its regulatory accounting for its subsidiaries doing business in Michigan and Oklahoma. 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 our state regulatory jurisdictions affected by restructuring legislation is presented in Note 8 of the Notes to Consolidated Financial Statements.

Corporate Separation

We have filed with the FERC and SEC seeking approval to separate our regulated and unregulated operations. Our plan for corporate separation would have complied with the requirements of Texas and Ohio restructuring legislation. In Texas, we intended to transfer the generation assets from the integrated electric operating companies (CPL and WTU) which operated in ERCOT prior to the effective date of the Texas Restructuring Legislation to unregulated generation companies. In Ohio, we intended to transfer transmission and distribution assets from the integrated companies to two new wires companies leaving CSPCo and OPCo as generating companies. We proposed amendments to the power pooling agreements to remove the four Ohio and Texas generating companies. Only those operating companies that continue to exist as integrated utilities would have been included in the amended power pooling agreements, which would govern energy exchanges among members and the allocation of their off-system purchases and sales. In connection with corporate separation, certain new interim power supply agreements have been proposed to provide power to distribution companies who will no longer own generation assets. Several state commissions, wholesale customer groups and other interested parties intervened in the FERC proceeding. Negotiated settlement agreements with the state regulatory commissions and other major intervenors were filed with the FERC in December 2001. In September 2002, the FERC conditionally approved our corporate separation plan as modified by the settlement agreements. Terms in the settlement agreements would be effective upon implementation of corporate separation. In addition, SEC approval of our corporate separation plan is required for its implementation. The Arkansas Commission intervened with the SEC, which has extended the length of time needed for the SEC's review. In order to execute this separation, we may be required to retire various debt securities and transfer assets between legal entities.

With the changes in our business strategy in response to current energy market/business conditions, management is evaluating changes to our corporate separation plans, including determining whether legal corporate separation is appropriate.

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, required the transfer of functional control of our transmission system to RTOs.

AEP East companies initially participated in the formation of the Alliance RTO. In December 2001, the FERC reversed prior approvals and rejected the Alliance RTO's filing. Subsequently, in May 2002 AEP announced an agreement with the PJM Interconnection to pursue terms for AEP East companies to participate in PJM with final agreements to be negotiated. In July 2002, the FERC conditionally approved our decision for AEP East companies to join PJM subject to certain conditions being met. The performance of these conditions are only partially under our control. In December 2002, AEP East companies in Indiana, Kentucky, Ohio and Virginia filed for state regulatory commission approval of their plans to transfer functional control of their transmission system to PJM based on statutory or regulatory requirements in those states. Those proceedings are currently pending. In February 2003, the Virginia legislature enacted legislation that would prohibit the transfer to an RTO, until at least July 2004, which is currently awaiting signature by the Governor of Virginia.

AEP West companies are members of ERCOT or the SPP. In May 2002, FERC accepted, conditionally, filings related to a proposed consolidation of the MISO and the SPP. In that order the FERC required the AEP West companies in SPP to file reasons why they should not be required to join MISO. In August 2002, we notified the FERC of our intent that our transmission assets in SPP would participate in MISO. Our SPP companies are also regulated by state public utility commissions, and the Louisiana and Arkansas commissions also filed responses to the FERC's RTO order indicating that additional analysis was required. Regulatory activities concerning various RTO issues are ongoing in Arkansas and Louisiana.

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

FERC Proposed Standard Market Design Security Standards

In 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking seeking to standardize the structure and operation of wholesale electricity markets across the country. The FERC published for comment its proposed security standards as part of the SMD. These standards are intended to ensure all market participants have a basic security program that effectively protects the electric grid and related market activities. Because the rule is not yet finalized, management cannot predict the effect of the final rule on our operations and financial results. See Note 9 for a complete discussion of these proposals.

Litigation

AEP is involved in various litigation. The details of significant litigation contingencies are disclosed in

Note 9 and summarized below.

Enron Bankruptcy

In 2002, certain subsidiaries of AEP filed claims in the bankruptcy proceeding of the Enron Corp. and its subsidiaries which are pending in the U.S. Bankruptcy Court for the Southern District of New York. At the date of Enron's bankruptcy, AEP had open trading contracts and trading accounts receivables and payables with Enron and various HPL related contingencies and indemnities including issues related to the underground Bammel gas storage facility and the cushion gas (or pad gas) required for its normal operation.

We believe that we have the right to utilize offsetting receivables and payables and related collateral across various Enron entities by offsetting approximately $110 million of trading payables owed to various Enron entities against trading receivables due to us. We believe we have legal defenses to any challenge that may be made to the utilization of such offsets. At this time we are unable to predict the ultimate resolution of these issues or their impact on results of operations and cash flows. See Note 9 for further discussion.

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 our consolidated federal income tax returns related to a COLI program resulted in a $319 million reduction in Net Income for 2000. AEP has appealed the Court's decision. See Note 18 for further discussion.

Shareholders' Litigation

In 2002 lawsuits alleging securities law violations, a breach of fiduciary duty for failure to establish and maintain adequate internal controls and violations of the Employee Retirement Income Security Act were filed against AEP, certain AEP executives, members of the AEP Board of Directors and certain investment banking firms. These cases are in the initial pleading stage. AEP intends to vigorously defend against these actions. See Note 9 for further discussion.

California Lawsuit

In 2002 the Lieutenant Governor of California filed a lawsuit in California Superior Court against forty energy companies including AEP and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP intends to vigorously defend against this action. See Note 9 for further discussion.

FERC Wholesale Fuel Complaints

In May 2000 and November 2001 certain TNC wholesale customers filed complaints with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs. The final resolution of this matter could have a negative impact on future results of operations, cash flow and financial condition. See Note 6 for further discussion.

Merger Litigation

In January 2002, a federal court ruled that the SEC did not properly find 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. See Note 9 for further discussion.

Arbitration of Williams Claim

In 2002 AEP filed its demand for arbitration with the American Arbitration Association to initiate formal arbitration proceedings in a dispute with the Williams Companies (Williams). The proceeding results from Williams' repudiation of its obligations to provide physical power deliveries to AEP and Williams' failure to provide the monetary security required for natural gas deliveries. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition. See Note 9 for further discussion.

Energy Market Investigations

During 2002 the FERC, the California attorney general, the PUCT, the SEC, the Department of Justice and the U.S. Commodity Futures Trading Commission (CFTC) initiated investigations into whether any entity, including Enron, manipulated short-term prices in electric energy or natural gas markets, exercised undue influence over wholesale prices or participated in fraudulent trading practices.

We have and will continue to provide information to the FERC, the SEC, state officials and the CFTC as required. See Note 9 for further discussion.

FERC Market Power Mitigation

A FERC order on our triennial market based wholesale power rate authorization update required certain mitigation actions that we would need to take for sales/purchases within our control area and required us to post information on our website regarding our power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. No such conference has been held and management is unable to predict the timing of any further action by the FERC or its affect on future results of operations and cash flows.

Other Litigation

We are 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.

Environmental Concerns and Issues

We will confront several new environmental requirements over the next decade with the potential for substantial control costs and premature retirement of some generating plants. These policies include: stringent controls on sulfur dioxide (SO2), nitrogen oxide (NOx) and mercury (Hg) emissions from future regulations or laws, or an adverse decision in the New Source Review litigation; a new Clean Water Act rule to reduce fish killed at once-through cooled power plants; and a possible future requirement to reduce carbon dioxide (CO2) emissions as the world endeavors to stabilize atmospheric concentrations of greenhouse gas emissions and avert global climatic changes.

Our environmental policy requires full compliance with all applicable legal requirements. In support of this policy, we invest in research through groups like the Electric Power Research Institute and directly through demonstration projects for new emission control technologies. We intend to continue in a leadership role to protect and preserve the environment while providing vital energy commodities and services to customers at fair prices.

We have a proven record of efficiently producing and delivering electricity and gas while minimizing the impact on the environment. We have spent billions of dollars to equip many of our facilities with pollution control technologies.

Multi-pollutant control legislation has been introduced in Congress and is supported by the Bush Administration. The legislation would regulate NOx, SO2, Hg and possibly CO2 emissions from electric generating plants. We are an advocate of comprehensive, multi-pollutant legislation so that compliance planning can be coordinated and collateral emission reductions maximized. Optimally, such legislation would establish reasonable emission reduction targets and compliance timetables based on sound science, utilize nationwide cap-and-trade programs for achieving compliance as cost-effectively as possible, protect fuel diversity and preserve the reliability of the nation's electric supply. Management is unable to predict the timing or magnitude of additional pollution control laws or regulations. If additional control technology is required on our facilities and their costs are not recoverable from customers through regulated rates or market prices, 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 special interest groups alleged that AEP System companies modified certain units at coal fired generating plants in violation of the Clean Air Act over a 20 year period.

Management believes its maintenance, repair and replacement activities were in conformity with the Clean Air Act and intends to vigorously pursue its defense. Management is unable to estimate the loss or range of loss related to the contingent liability 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. If we do not prevail, any capital and operating costs of additional pollution control equipment or any penalties imposed would adversely affect future results of operations, cash flows and possibly financial condition unless such costs can be recovered. See

Note 9 for further discussion.

NOx Reductions

Federal EPA issued a NOx Rule and adopted a revised rule (the Section 126 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 compliance date for these rules is May 31, 2004.

In 2000, the Texas Commission on Environmental Quality (formerly the Texas Natural Resource Conservation Commission) adopted rules requiring significant reductions in NOx emissions from utility sources, including TCC and SWEPCo. The compliance date is May 2003 for TCC and May 2005 for SWEPCo.

AEP is installing a variety of emission control technologies to reduce NOx emissions to comply with the applicable state and Federal NOx requirements including selective catalytic reduction (SCR) technology and non-SCR technologies. The AEP NOx compliance plan is a dynamic plan that is continually reviewed and revised. Our current estimates indicate that compliance with the above rules could result in required capital expenditures in the range of $1.3 billion to $2 billion of which $843 million has been spent through December 31, 2002. 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. See Note 9 for further discussion.

Superfund and State Remediation

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 non-hazardous 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 authorizes Federal EPA to administer the clean-up programs. As of year-end 2002, subsidiaries of AEP are named by the Federal EPA as a PRP for five sites. There are six additional sites for which we have received information requests which could lead to PRP designation. We have also been named potentially liable at six 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. 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 superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the 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 or its subsidiaries in the future under Superfund, results of operations, cash flows and possibly financial condition would be adversely affected unless the costs can be recovered from customers.

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 CO2, 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 in 2003. 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 that due to President Bush's opposition to legislation mandating greenhouse 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. AEP has for many years been a leader in pursuing voluntary actions to control greenhouse gas emissions. We recently expanded on our commitment in this area by joining the Chicago Climate Exchange, a pilot greenhouse gas emission reduction and trading program, under which we are obligated to reduce or offset 18 million tons of CO2 emissions during 2003-2006.

The acquisition of 4,000 MW of coal-fired generation in the United Kingdom in December 2001 exposes these assets to potential CO2 emission control obligations since the U.K. has become a party to the Kyoto Protocol.

Control of Mercury Emissions

In December 2000 Federal EPA issued a regulatory determination listing the electric generating sector as a source category under the Clean Air Act for development of maximum achievable control technology standards to control emissions of hazardous air pollutants, including Hg. Federal EPA is expected to issue proposed regulations in 2003 and develop a final rule in 2004. We cannot predict the outcome of these regulatory proceedings, or the costs to comply with any new standards adopted by Federal EPA. The costs associated with compliance could be material. However, 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.

Costs for Spent Nuclear Fuel and Decommissioning

I&M, as the owner of the Cook Plant, and TCC, as a partial owner of STP, have 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 I&M and TCC participate in the DOE's SNF disposal program which is described in Note 9 of the Notes to Consolidated Financial Statements. Since 1983 I&M has collected $303 million from customers for the disposal of nuclear fuel consumed at the Cook Plant. $117 million of these funds have been deposited in external trust funds to provide for the future disposal of SNF and $186 million has been remitted to the DOE. TCC has collected and remitted to the DOE, $53 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 the companies 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 TCC 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 and I&M 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. On January 17, 2003, the U.S. Court of Federal Claims ruled in favor of I&M on the issue of liability. The case continues on the issue of damages owed to I&M by the DOE. 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 of SNF 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 (now Exelon Generation Company, LLC). The settlement adjusted the fees Exelon was required to pay to DOE for disposal of SNF. The fee adjustment allowed Exelon to skip payments to the DOE to make up for Exelon's damages from DOE's breach of its contract obligation to dispose of SNF from commercial nuclear power plants. The companies believe the settlement was unlawful as it would force other utilities (rather than DOE) to compensate Exelon for the damages it had incurred from DOE's breach of contract. In September 2002, the U.S. Court of Appeals for the Eleventh Circuit found that DOE acted improperly by adopting the fee adjustment provision of this settlement, that the fee adjustment provisions of the settlement harmed other utilities who pay into the fund and violated the federal nuclear waste management laws and that the fee adjustment provisions of the settlement were null and void.

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, 2002, the total decommissioning trust fund balance for Cook Plant was $618 million which includes earnings on the trust investments. Studies completed in 1999 for STP estimate TCC'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, 2002, the total decommissioning trust fund for TCC's share of STP was $98 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, future results of operation, cash flows and possibly financial conditions would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Other Environmental Concerns

We are 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.

Other Matters

Seasonality

Sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change depending on the nature and location of facilities we acquire and the terms of power sale contracts we enter. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. AEP expects that unusually mild weather in the future could diminish its results of operations and may impact its financial condition.

Sustained Earnings Improvement Initiative

In response to difficult conditions in AEP's business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth. Termination benefits expense relating to 1,120 terminated employees totaling $75.4 million pre-tax was recorded in the fourth quarter of 2002. We determined that the termination of the employees under our SEI initiative did not constitute a curtailment under the provisions of SFAS No. 88 "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits". In addition, certain buildings and corporate aircraft are being sold in an effort to reduce ongoing operating expenses. See Note 11 for additional information.

Non-Core Wholesale Investments

Additional market deterioration associated with our non-core wholesale investments, including our U.K. operations, could have an adverse impact on our future results of operations and cash flows. Significant long-term changes in external market conditions could lead to additional write-offs and potential divestitures of our wholesale investments, including, but not limited to, our U.K. operations.

Elk City Referendum

In October 2002, the City Commission of Elk City, Oklahoma voted to hold a referendum seeking voter approval of a $20.4 million acquisition of PSO’s distribution assets within the city limits. The vote occurred in December 2002 with the referendum being defeated.

Snohomish Settlement

In February 2003, AEP and the Public Utility District No. 1 of Snohomish County, Washington (Snohomish) agreed to terminate their long-term contract signed in January 2001. Snohomish also agreed to withdraw its complaint before the FERC regarding this contract.

Investments Limitations

Our investment in certain types of activities, including guarantees of debt, 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, 2002, AEP's investment in EWGs and FUCOs was $2.0 billion, including guarantees of debt, compared to AEP’s limit of $2.8 billion.

SEC rules under PUHCA permit AEP to invest up to 15% of consolidated capitalization (such amount was $3.2 billion at December 31, 2002) in energy-related companies, including marketing and/or trading of electricity, gas and other energy commodities.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

Consolidated Statements of Operations

(in millions - except per share amounts)

	Year Ended December 31, 2002	2001	2000
REVENUES:			
Wholesale Electricity	$ 8,366	$ 6,976	$ 7,392
Wholesale Gas	2,622	2,321	442
Domestic Electricity Delivery	3,551	3,356	3,174
Other Investment	16	114	105
TOTAL REVENUES	14,555	12,767	11,113
EXPENSES:			
Fuel and Purchased Energy:			
Electricity	3,154	2,195	3,470
Gas	3,153	2,749	410
TOTAL FUEL AND PURCHASED ENERGY	6,307	4,944	3,880
Maintenance and Other Operation	4,013	3,710	3,482
Non-recoverable Merger Costs	10	21	203
Asset Impairments	867	-	-
Depreciation and Amortization	1,377	1,243	1,091
Taxes Other Than Income Taxes	718	667	683
TOTAL EXPENSES	13,292	10,585	9,339
OPERATING INCOME	1,263	2,182	1,774
OTHER INCOME	445	335	95
LESS: INVESTMENT VALUE AND OTHER IMPAIRMENT LOSSES	321	-	-
LESS: OTHER EXPENSES	321	187	77
LESS: INTEREST	785	844	999
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARIES	11	10	11
MINORITY INTEREST IN FINANCE SUBSIDIARY	35	13	-
INCOME BEFORE INCOME TAXES	235	1,463	782
INCOME TAXES	214	546	602
INCOME BEFORE DISCONTINUED OPERATIONS, EXTRAORDINARY ITEMS AND CUMULATIVE EFFECT	21	917	180
DISCONTINUED OPERATIONS (LOSS) INCOME (NET OF TAX)	(190)	86	122
EXTRAORDINARY LOSSES (NET OF TAX):			
DISCONTINUANCE OF REGULATORY ACCOUNTING FOR GENERATION	-	(48)	(35)
LOSS ON REACQUIRED DEBT	-	(2)	-
CUMULATIVE EFFECT OF ACCOUNTING CHANGE (NET OF TAX)	(350)	18	-
NET INCOME (LOSS)	$ (519)	$ 971	$ 267
AVERAGE NUMBER OF SHARES OUTSTANDING	332	322	322
EARNINGS (LOSS) PER SHARE:			
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect of Accounting Change	$ 0.06	$ 2.85	$ 0.56
Discontinued Operations	(0.57)	0.26	0.38
Extraordinary Losses	-	(0.16)	(0.11)
Cumulative Effect of Accounting Change	(1.06)	0.06	-
Earnings (Loss) Per Share (Basic and Diluted)	$(1.57)	$ 3.01	$ 0.83
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, 2002	December 31, 2001
ASSETS		
CURRENT ASSETS:		
Cash and Cash Equivalents	$ 1,213	$ 224
Accounts Receivable:		
Customers	466	343
Miscellaneous	1,394	1,365
Allowance for Uncollectible Accounts	(119)	(69)
Fuel, Materials and Supplies	1,166	1,037
Energy Trading and Derivative Contracts	1,046	2,125
Other	935	639
TOTAL CURRENT ASSETS	6,101	5,664
PROPERTY PLANT AND EQUIPMENT:		
Electric:		
Production	17,031	17,054
Transmission	5,882	5,764
Distribution	9,573	9,309
Other (including gas and coal mining assets and nuclear fuel)	3,965	4,272
Construction Work in Progress	1,406	1,015
Total Property, Plant and Equipment	37,857	37,414
Accumulated Depreciation and Amortization	16,173	15,310
NET PROPERTY, PLANT AND EQUIPMENT	21,684	22,104
REGULATORY ASSETS	2,688	3,162
SECURITIZED TRANSITION ASSETS	735	-
INVESTMENTS IN POWER AND DISTRIBUTION PROJECTS	283	633
ASSETS HELD FOR SALE	247	721
ASSETS OF DISCONTINUED OPERATIONS	-	3,954
GOODWILL	396	392
LONG-TERM ENERGY TRADING AND DERIVATIVE CONTRACTS	824	795
OTHER ASSETS	1,783	1,872
TOTAL ASSETS	$34,741	$39,297

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Consolidated Balance Sheets

	December 31, 2002	December 31, 2001
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts Payable	$ 2,042	$ 1,914
Short-term Debt	3,164	4,011
Long-term Debt Due Within One Year*	1,633	1,095
Energy Trading and Derivative Contracts	1,147	1,877
Other	1,804	1,924
TOTAL CURRENT LIABILITIES	9,790	10,821
LONG-TERM DEBT*	8,487	8,410
EQUITY UNIT SENIOR NOTES	376	-
LONG-TERM ENERGY TRADING AND DERIVATIVE CONTRACTS	484	603
DEFERRED INCOME TAXES	3,916	4,500
DEFERRED INVESTMENT TAX CREDITS	455	491
DEFERRED CREDITS AND REGULATORY LIABILITIES	765	819
DEFERRED GAIN ON SALE AND LEASEBACK - ROCKPORT PLANT UNIT 2	185	194
OTHER NONCURRENT LIABILITIES	1,903	1,334
LIABILITIES HELD FOR SALE	91	87
LIABILITIES OF DISCONTINUED OPERATIONS	-	2,582
COMMITMENTS AND CONTINGENCIES (Note 9)		
CERTAIN SUBSIDIARY OBLIGATED, MANDATORILY REDEEMABLE, PREFERRED SECURITIES OF SUBSIDIARY TRUSTS HOLDING SOLELY JUNIOR SUBORDINATED DEBENTURES OF SUCH SUBSIDIARIES	321	321
MINORITY INTEREST IN FINANCE SUBSIDIARY	759	750
CUMULATIVE PREFERRED STOCK OF SUBSIDIARIES*	145	156
COMMON SHAREHOLDERS' EQUITY:		
Common Stock-Par Value $6.50: (2002 / 2001) Shares Authorized. .600,000,000 / 600,000,000; Shares Issued. . . .347,835,212 / 331,234,997 (8,999,992 shares were held in treasury at December 31, 2002 and 2001)	2,261	2,153
Paid-in Capital	3,413	2,906
Accumulated Other Comprehensive Income (Loss)	(609)	(126)
Retained Earnings	1,999	3,296
TOTAL COMMON SHAREHOLDERS' EQUITY	7,064	8,229
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$34,741	$39,297

**See Accompanying Schedules.*

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES

Consolidated Statements of Cash Flows

(in millions)

	Year Ended December 31, 2002	2001	2000
OPERATING ACTIVITIES:			
Net Income (Loss)	$ (519)	$ 971	$ 267
Plus: Discontinued Operations	540	(86)	(122)
Net Income from Continuing Operations	21	885	145
Adjustments for Noncash Items:			
Asset Impairments, Investment Value and Other Impairments	1,188	-	-
Depreciation and Amortization	1,403	1,277	1,152
Deferred Investment Tax Credits	(31)	(29)	(36)
Deferred Income Taxes	(66)	157	(190)
Amortization of Operating Expenses and Carrying Charges	40	40	48
Cumulative Effect of Accounting Change	-	(18)	-
Equity Earnings of Yorkshire Electricity Group plc	-	-	(44)
Extraordinary Loss	-	50	35
Deferred Costs Under Fuel Clause Mechanisms	(31)	340	(449)
Mark-to-Market of Energy Trading Contracts	263	(257)	(170)
Miscellaneous Accrued Expenses	30	(384)	217
Changes in Certain Current Assets and Liabilities:			
Accounts Receivable (net)	(152)	1,766	(1,530)
Fuel, Materials and Supplies	(127)	(78)	149
Accrued Revenues	(283)	35	(71)
Accounts Payable	52	(478)	1,292
Taxes Accrued	(216)	(147)	171
Payment of Disputed Tax and Interest Related to COLI	-	-	319
Change in Other Assets	(177)	(239)	(283)
Change in Other Liabilities	(237)	(161)	386
Net Cash Flows From Operating Activities	1,677	2,759	1,141
INVESTING ACTIVITIES:			
Construction Expenditures	(1,722)	(1,654)	(1,468)
Purchase of Gas Pipe Line	-	(727)	-
Purchase of U.K. Generation	-	(943)	-
Purchase of Coal Company	-	(101)	-
Purchase of Barging Operations	-	(266)	-
Purchase of Wind Generation	-	(175)	-
Proceeds from Sale of Retail Electric Providers	146	-	-
Proceeds from Sale of Foreign Investments	1,117	383	-
Proceeds from Sale of U.S. Generation	-	265	-
Other	37	(42)	(18)
Net Cash Flows Used For Investing Activities	(422)	(3,260)	(1,486)
FINANCING ACTIVITIES:			
Issuance of Common Stock	656	11	14
Issuance of Minority Interest	-	744	-
Issuance of Long-term Debt	2,893	2,863	878
Issuance of Equity Unit Senior Notes	334	-	-
Retirement of Cumulative Preferred Stock	(10)	(5)	(21)
Retirement of Long-term Debt	(2,514)	(1,570)	(1,303)
Change in Short-term Debt (net)	(829)	(790)	1,328
Dividends Paid on Common Stock	(793)	(773)	(805)
Dividends on Minority Interest in Subsidiary	-	(5)	-
Net Cash Flows From (Used for) Financing Activities	(263)	475	91
Effect of Exchange Rate Changes on Cash	(3)	(1)	30
Net Increase (Decrease) in Cash and Cash Equivalents	989	(27)	(224)
Cash and Cash Equivalents from Continuing Operations - Beginning of Period	224	251	475
Cash and Cash Equivalents from Continuing Operations - End of Period	$1,213	$ 224	$ 251
Net Increase (Decrease) in Cash and Cash Equivalents from Discontinued Operations	$ (100)	$ 17	$ (17)
Cash and Cash Equivalents from Discontinued Operations - Beginning of Period	108	91	108
Cash and Cash Equivalents from Discontinued Operations - End of Period	$ 8	$ 108	$ 91

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 Stock Shares	Common Stock Amount	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
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 Hedged Derivatives					(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
Issuances	17	108	568	-	-	676
Cash Dividends Declared	-	-	-	(793)	-	(793)
Other	-	-	(61)	15	-	(46)
						(163)
Comprehensive Income:						
Other Comprehensive Income, Net of Taxes						
Foreign Currency Translation Adjustment	-	-	-	-	117	117
Unrealized Gain (Loss) on Hedged Derivatives					(13)	(13)
Minimum Pension Liability	-	-	-	-	(585)	(585)
Unrealized Loss on Securities Available For Sale					(2)	(2)
Net Income (Loss)	-	-	-	(519)		(519)
Total Comprehensive Income						(1,002)
DECEMBER 31, 2002	348	$2,261	$3,413	$1,999	$(609)	$7,064

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies:

Business Operations – AEP's (the Company's) principal business conducted by its eleven domestic electric utility operating companies is the generation, transmission and distribution of electric power. 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, other commodities in the United States and Europe. In addition, the Company's domestic operations include non-regulated independent power and cogeneration facilities, coal mining and intra-state midstream natural gas operations in Louisiana and Texas.

International operations include supply of electricity and other non-regulated power generation projects in the United Kingdom, and to a lesser extent in Mexico, Australia, China and the Pacific Rim region. These operations are either wholly-owned or partially-owned by various AEP subsidiaries. We also maintained operations in Brazil through the fourth quarter of 2002. See Note 13 for discussion of impaired investments and assets held for sale.

The Company also operates domestic barging operations, provides various energy related services and furnishes communications related services domestically. See Note 13 for further discussion of changes in our communications related business and other business operations announced in 2002.

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 China, Mexico and Brazil are regulated by the authorities of that country and are generally subject to price controls.

Principles of Consolidation – AEP's consolidated financial statements include AEP Co., Inc. and its wholly-owned and majority-owned subsidiaries consolidated with their wholly-owned or substantially controlled subsidiaries. Significant intercompany items are eliminated in consolidation. Equity investments not substantially controlled 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 TCC, TNC, and SWEPCo in September 1999 and in Arkansas by SWEPCo in September 1999. See Note 8, "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 – Domestic electric utility property, plant and equipment are stated at original cost of the acquirer. Property, plant and equipment of the non-regulated 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 overhead incurred to operate and maintain plant are included in operating expenses. Plants are tested for impairment as required under SFAS 144. See further discussion of impairments in Note 13.

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 2002, 2001 and 2000 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 2002, 2001 and 2000.

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 2002
Production:	
Steam-Nuclear	2.5% to 3.4%
Steam-Fossil-Fired	2.6% to 4.5%
Hydroelectric-Conventional and Pumped Storage	1.9% to 3.4%
Transmission	1.7% to 3.0%
Distribution	3.3% to 4.2%
Other	1.8% to 9.9%

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%

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. These costs are included in the cost of coal charged to fuel expense for coal used by utility operations. Current average amortization rates are $0.32 per ton in 2002, $3.46 per ton in 2001 and $5.07 per ton in 2000. In 2001, an AEP subsidiary sold coal mines in Ohio and West Virginia. See Note 12, Acquisitions, Dispositions and Discontinued Operations for further discussion of the changes in our coal investments leading to the decline in amortization rates for 2002.

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

Inventory – Except for PSO, TCC and TNC, the regulated domestic utility companies value fossil fuel inventories using a weighted average cost method. PSO, TCC and TNC, utilize the LIFO method to value fossil fuel inventories. For those domestic utilities whose generation is unregulated, 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. Materials and supplies inventories are carried at average cost.

Non-trading gas inventory is carried at the lower of cost or market. In compliance with EITF 02-03 as described in the New Accounting Pronouncements section of Note 1, natural gas inventories held in connection with trading operations at October 25, 2002 continued to be carried at fair value until December 31, 2002, and inventory purchased from October 26 through December 31, 2002 was carried at the lower of cost or market. Effective January 1, 2003, all natural gas inventories held in connection with trading operations will be adjusted to the historical cost basis and carried at the lower of cost or market. We estimate the adjustment in January 2003 will decrease the value of natural gas inventories held in connection with trading operations by approximately $39 million. This change will be accounted for as a cumulative effect of a change in accounting principle.

Accounts Receivable – AEP Credit Inc. factors accounts receivable for certain of the domestic utility subsidiaries and, until the first quarter of 2002, factored accounts receivable for certain 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 company's balance sheet. See Note 23 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 in 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 Statements of Cash Flows in Effect of Exchange Rate Changes 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-recoveries 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 $143 million at December 31, 2002 and $139 million at December 31, 2001. See also Note 7 "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. 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 6, "Rate Matters" and Note 8, "Customer Choice and Industry Restructuring" for further information about fuel recovery.

Revenue Recognition -

<u>*Regulatory Accounting*</u> - The consolidated financial statements of AEP and the financial statements of electric operating subsidiary companies with cost-based rate-regulated operations (I&M, KPCo, PSO, and a portion of APCo, OPCo, CSPCo, TCC, TNC and SWEPCo), 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, regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers through regulated revenues in the same accounting period. Regulatory liabilities are also recorded to provide currently for refunds to customers that have not yet been made.

When recovery of regulatory assets is probable 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.

Traditional Electricity Supply and Delivery Activities - Revenues are recognized on the accrual or settlement basis for normal retail and wholesale electricity supply sales and electricity transmission and distribution delivery services. The 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 purchased electricity is received and when expenses are incurred.

Domestic Gas Pipeline and Storage Activities – Revenues are recognized from domestic gas pipeline and storage services when gas is delivered to contractual meter points or when services are provided. Transportation and storage revenues also include the accrual of earned, but unbilled and/or not yet metered gas.

Substantially all of the forward gas purchase and sale contracts, excluding wellhead purchases of natural gas, swaps and options for the domestic pipeline operations, qualify as derivative financial instruments as defined by SFAS 133. Accordingly, net gains and losses resulting from revaluation of these contracts to fair value during the period are recognized currently in the results of operations, appropriately discounted and net of applicable credit and liquidity reserves.

Energy Marketing and Trading Transactions – In 2000, 2001 and throughout the majority of 2002, AEP engaged in wholesale electricity, natural gas and other commodity 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. We use the mark-to-market method of accounting for trading activities as required by EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10). Under the mark-to-market method of accounting, gains and losses from settlements of forward trading contracts are recorded net in revenues. For energy contracts not yet settled, whether physical or financial, changes in fair value are recorded net in revenues as unrealized gains and losses from mark-to-market valuations. When positions are settled and gains and losses are realized, the previously recorded unrealized gains and losses from mark-to-market valuations are reversed. In October 2002, management announced plans to focus on wholesale markets around owned assets.

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 AEP-developed valuation models. The models are derived from internally assessed market prices with the exception of the NYMEX gas curve, where we use daily settled prices. All fair value amounts are net of appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Such valuation adjustments provide for a better approximation of fair value. 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 prices, at the time of settlement, do not correlate with AEP-developed price models.

As explained above, the effect on AEP's Consolidated Statements of Operations of marking to market open electricity trading contracts in AEP's regulated jurisdictions is deferred as regulatory assets (losses) or liabilities (gains) 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 are part of Energy Trading and Derivative Contracts assets or liabilities as appropriate.

Construction Projects for Outside Parties – Certain AEP entities engage in construction projects for outside parties that are accounted for on the percentage-of-completion method of revenue recognition. This method recognizes revenue in proportion to costs incurred compared to total estimated costs.

Debt Instrument Hedging and Related Activities – In order to mitigate the risks of market price and interest rate fluctuations, AEP enters into contracts to manage the exposure to unfavorable changes in the cost of debt to be issued. These anticipatory debt instruments are entered into in order to manage the change in interest rates between the time a debt offering is initiated and the issuance of the debt (usually a period of 60 days). Gains or losses from these transactions are deferred and amortized over the life of the debt issuance with the amortization included in interest charges. There were no such forward contracts outstanding at December 31, 2002 or 2001. See Note 17 – "Risk Management, Financial Instruments and Derivatives" for further discussion of the accounting for risk management transactions.

Levelization of Nuclear Refueling Outage Costs - In order to match costs with regulated revenues, incremental operation and maintenance costs associated with periodic 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 each year 1999 through 2002 leaving $40 million as a SFAS 71 Regulatory Asset at December 31, 2002 on the Consolidated Balance Sheets.

Other Income and Other Expenses – Other Income includes non-operational revenue including area business development and river transportation, 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 miscellaneous income. Other Expenses includes non-operational expense including area business development and river transportation, losses on dispositions of property, miscellaneous amortization, donations and various other non-operating and miscellaneous expenses.

AEP Consolidated Other Income and Deductions

	2002	2001	2000
		December 31, (in millions)	
OTHER INCOME:			
Equity Earnings	$ 104	$ 123	$ 22
Non-operational Revenue	187	123	71
Interest and Miscellaneous Income	25	16	2
Gain on Sale of Frontera	-	73	-
Gain on Sale of Retail Electric Provider	129	-	-
Total Other Income	$ 445	$ 335	$ 95
OTHER EXPENSES:			
Property Taxes and Miscellaneous Expenses	$ 142	$ 68	$ 28
Non-operational Expenses	179	56	49
Fiber Optic and Datapult Exit Costs	-	49	-
Provision for Loss - Airplane	-	14	-
Total Other Expenses	$ 321	$ 187	$ 77

Income Taxes - The AEP System 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 Consolidated Statements of Operations.

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 Loss on Reacquired Debt, an extraordinary item on the Consolidated Statements of Operations. See discussion of SFAS 145 in New Accounting Pronouncements section of this note for new treatment effective in 2003.
Debt discount or premium and debt issuance expenses are deferred and amortized utilizing the effective interest rate method over the term of the related debt. The amortization expense is 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.

Goodwill and Intangible Assets – In June 2001, the FASB issued SFAS 141, Business Combinations, and SFAS 142, Goodwill and Other Intangible Assets.

SFAS 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001 and established new standards for the recognition of certain identifiable intangible assets, separate from goodwill. We adopted the provisions of SFAS 141 effective July 1, 2001. See Note 12 for further discussion of acquisitions initiated after June 30, 2001 and Note 3 for further discussion of our components of goodwill and intangible assets.

SFAS 142 requires that goodwill and intangible assets with finite useful lives no longer be amortized, but instead tested for impairment at least annually. SFAS 142 also requires that intangible assets with finite useful lives be amortized over their respective estimated lives to the estimated residual values. In accordance with SFAS 142, for all business combinations with an acquisition date before July 1, 2001, we amortized goodwill and intangible assets with indefinite lives through December 2001, and then ceased amortization. The goodwill associated with those business combinations with an acquisition date before July 1, 2001 was amortized on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities which was amortized on a straight-line basis over 10 years. In accordance with SFAS 142, for all business combinations with an acquisition date after June 30, 2001, we have not amortized goodwill and intangible assets with indefinite lives. Intangible assets with finite lives continue to be amortized over their respective estimated lives ranging from 5 to 10 years. See Note 3 for total goodwill, accumulated amortization and the impact on operations of the adoption of SFAS 142.

In early 2002, we began testing our goodwill and intangible assets with indefinite useful lives for impairment, in accordance with SFAS 142. See Note 3 for the results of our testing and the corresponding net transitional impairment loss recorded as a Cumulative Effect of Accounting Change during 2002.

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.

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 (Loss) - 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 (Loss) – Other comprehensive income (loss) 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 (Loss) for AEP.

Components	2002	December 31, 2001	2000
		(in millions)	
Foreign Currency Adjustments	4	$(113)	$ (99)
Unrealized Losses On Securities	(2)	-	-
Unrealized Gain (Loss) on Hedged Derivatives	(16)	(3)	-
Minimum Pension Liability	(595)	(10)	(4)
	$(609)	$(126)	$(103)

Segment Reporting – The AEP System has adopted SFAS No. 131, which requires disclosure of selected financial information by business segment as viewed by the chief operating decision-maker. See Note 16 "Business Segments" for further discussion and details regarding segments.

Common Stock Options – At December 31, 2002, AEP has two stock-based employee compensation plans with outstanding stock options, which are described more fully in Note 15. We account for these plans under the recognition and measurement principles of APB Opinion No. 25, *Accounting for Stock Issued to Employees* and related Interpretations. No stock-based employee compensation expense is reflected in earnings, as all options granted under these plans had exercise prices equal to or above the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income (loss) and earnings (loss) per share as if the company had applied the fair value recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation", to stock-based employee compensation.

	Year Ended December 31, 2002	2001	2000
	(in millions except per share data)		
Net Income(Loss), as reported	$ (519)	$ 971	$ 267
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(9)	(12)	(3)
Pro forma net income (loss)	$ (528)	$ 959	$ 264
Earnings (Loss) per share:			
Basic - as reported	$(1.57)	$3.01	$0.83
Basic - pro forma	$(1.59)	$2.98	$0.82
Diluted - as reported	$(1.57)	$3.01	$0.83
Diluted - pro forma	$(1.59)	$2.97	$0.82

Earnings Per Share (EPS) – AEP calculates earnings (loss) per share in accordance with SFAS No. 128, "Earnings Per Share" (see Note 19). Basic earnings (loss) per common share is calculated by dividing net earnings (loss) available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards. The effects of stock options have not been included in the fiscal 2002 diluted loss per common share calculation as their effect would have been anti-dilutive. Basic and diluted EPS are the same in 2002, 2001 and 2000.

Reclassification – Beginning in the fourth quarter of 2002, AEP elected to begin netting certain assets and liabilities related to forward physical and financial transactions. This is done in accordance with FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts" and Emerging Issues Task Force Topic D-43, "Assurance That a Right of Setoff is Enforceable in a Bankruptcy under FASB Interpretation No. 39". Transactions with common counterparties have been netted at the applicable entity level, by commodity and type (physical or financial) where the legal right of offset exists. For comparability purposes, prior periods presented in this report have been netted in accordance with this policy.

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

New Accounting Pronouncements

SFAS 142, "Goodwill and Other Intangible Assets", was effective for AEP on January 1, 2002. The adoption of SFAS 142 required the transition testing for impairment of all indefinite lived intangibles by the end of the first quarter 2002 and initial testing of goodwill by the end of the second quarter 2002. In the first quarter 2002, AEP completed testing the goodwill of its domestic operations and its indefinite lived intangible assets and there was no impairment. In the second quarter 2002, we completed initial testing for goodwill impairment of our U.K. and Australian retail electricity and supply operations. The fair values of the U.K. and Australia retail electricity and supply operations were estimated using a combination of market values based on recent market transactions and cash flow projections. As a result of that testing, we determined that we had a net transitional impairment loss, which is reported as a cumulative effect of a change in accounting principle. See Notes 2, 3, 12 and 13 for further discussion of the actual impairment charges and sales of impaired assets.

SFAS 142 also changed the accounting and reporting for goodwill and other intangible assets. In accordance with SFAS 142 goodwill and indefinite lived intangible assets acquired through acquisition after June 30, 2001 were not amortized. Effective January 1, 2002, amortization related to goodwill and indefinite lived intangible assets acquired before July 1, 2001 ceased. SFAS 142 requires that other intangible assets be separately identified and if they have finite lives, they must be amortized over that life. See Note 3 for amortization lives of our intangible assets.

SFAS 143, "Accounting for Asset Retirement Obligations", is effective for AEP on January 1, 2003. SFAS 143 generally applies to legal obligations associated with the retirement of long-lived assets. A company is required to recognize an estimated liability for any legal obligations associated with the future retirement of its long-lived assets. The liability is measured at fair value and is capitalized as part of the related asset's capitalized cost. The increase in the capitalized cost is included in determining depreciation expense over the expected useful life of the asset. The catch-up effect of adopting SFAS 143 will be recorded as a cumulative effect of an accounting change. Additionally, because the asset retirement obligation is recorded initially at fair value, accretion expense (similar to interest) will be recognized each period as an operating expense in the statement of operations.

The regulated entities have an asset retirement obligation associated with nuclear decommissioning costs for the Cook and STP Nuclear Plants and possibly other obligations. We expect to establish regulatory assets and liabilities that will result in no cumulative effect adjustment of adopting SFAS 143 for the regulated entities.

In addition, the regulated transmission and distribution entities have asset retirement obligations related to the final retirement of certain transmission and distribution lines. There are also underground storage tanks located at various sites throughout the AEP System and PCB's are contained in certain transformer rectifier sets at power plants. The amounts relating to these obligations cannot be determined because the entities are not able to estimate the final retirement dates for these facilities.

In January 2003, the SEC Staff concluded that SFAS 143 also precludes an entity from recording an expense for estimated costs associated with the removal or retirement of assets that result from other than legal obligations. The SEC Staff concluded that amounts that are included in accumulated depreciation related to estimated removal costs arising from other than legal obligations should be written off as part of the cumulative effect of adopting SFAS 143 unless the company is regulated under SFAS 71. Companies regulated under SFAS 71 may continue to include removal costs in depreciation rates but must quantify the removal costs included in accumulated depreciation as regulatory liabilities in footnote disclosure. The AEP registrant subsidiaries that are regulated entities have included estimated removal costs for non-legal retirement obligations in book depreciation rates.

For non-regulated entities, including certain formerly regulated generation facilities, asset retirement obligations associated with wind farms, closure costs associated with power plants in the U.K. and possibly other items will be incurred. Also the amount of removal costs embedded in accumulated depreciation is expected to result in a favorable cumulative effect adjustment to net income. However, we have not completed our determination of the net effect of these items on first quarter 2003 results of operations upon the adoption of the provisions of this standard.

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 replaced, SFAS 121, "Accounting for Long-lived Assets and for Long-lived Assets to be Disposed Of." AEP adopted SFAS 144 effective January 1, 2002. The adoption of SFAS 144 did not materially affect AEP's results of operations or financial conditions. See Notes 3 and 13 for discussion of impairments recognized in 2002, affected by SFAS 144.

In April 2002, the FASB issued SFAS 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections". SFAS 145 rescinds SFAS 4, "Reporting Gains and Losses from Extinguishment of Debt", effective for fiscal years beginning after May 15, 2002. SFAS 4 required gains and losses from extinguishment of debt to be aggregated and classified as an extraordinary item if material. In 2003, for financial reporting purposes AEP will reclassify extraordinary losses net of tax on reacquired debt of $2 million for 2001.

In October 2002, the Emerging Issues Task Force of the FASB reached a final consensus on Issue No. 02-3, "Recognition and Reporting of Gains and Losses on Energy Contracts under Issues No. 98-10 and 00-17" (EITF 02-3). EITF 02-3 rescinds EITF 98-10 and related interpretive guidance. Under EITF 02-3, mark-to-market accounting is precluded for energy trading contracts that are not derivatives pursuant to SFAS 133. The consensus to rescind EITF 98-10 will also eliminate any basis for recognizing physical inventories at fair value other than as provided by generally accepted accounting principles. The consensus is effective for fiscal periods beginning after December 15, 2002, and applies to all energy trading contracts entered into and inventory purchased through October 25, 2002. Effective January 1, 2003, nonderivative energy contracts are required to be accounted for on a settlement basis and inventory is required to be presented at the lower of cost or market. The effect of implementing this consensus will be reported as a cumulative effect of an accounting change. Such contracts and inventory will continue to be accounted for at fair value through December 31, 2002. Energy contracts that qualify as derivatives will continue to be accounted for at fair value under SFAS 133.

Effective January 1, 2003, EITF 02-3 requires that gains and losses on all derivatives, whether settled financially or physically, be reported in the income statement on a net basis if the derivatives are held for trading purposes. Previous guidance in EITF 98-10 permitted non-financial settled energy trading contracts to be reported either gross or net in the income statement. Prior to the third quarter of 2002, we recorded and reported upon settlement, sales under forward trading contracts as revenues and purchases under forward trading contracts as purchased energy expenses. Effective July 1, 2002, we reclassified such forward trading revenues and purchases on a net basis, as permitted by EITF 98-10. The reclassification of such trading activity to a net basis of reporting resulted in a substantial reduction in both revenues and purchased energy expense, but did not have any impact on our financial condition, results of operations or cash flows.

Effective July 1, 2002, we modified our valuation procedures for estimating the fair value of energy trading contracts at inception. Unrealized gain or loss at inception is recognized only when the fair value of a contract is obtained from a quoted market price in an active market or is otherwise evidenced by comparison to other observable market data. Any fair value changes subsequent to the inception of a contract, however, are recognized immediately based on the best market data available. We now also use such procedures for determining unrealized gain or loss at inception for all derivative contracts.

In June 2002, FASB issued SFAS 146 which addresses accounting for costs associated with exit or disposal activities. This statement supersedes previous accounting guidance, principally EITF No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under EITF No. 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. SFAS 146 also establishes that the liability should initially be measured and recorded at fair value. The timing of recognizing future costs related to exit or disposal activities, including restructuring, as well as the amounts recognized may be affected by SFAS 146. We will adopt the provisions of SFAS 146 for exit or disposal activities initiated after December 31, 2002.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45) which requires that a liability related to issuing a guarantee be recognized, as well as additional disclosures of guarantees. This new guidance is an interpretation of SFAS Nos. 5, 57 and 107 and a rescission of FIN No. 34. The initial recognition and initial measurement provisions of FIN 45 are effective on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements of FIN 45 are effective for financial statements of interim and annual periods ending after December 15, 2002. We do not expect that the implementation of FIN 45 will materially affect results of operations, cash flows or financial condition. See guarantee details discussed in Note 10.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure", which amends SFAS No. 123, "Accounting for Stock-Based Compensation". SFAS 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. Under the fair value based method, compensation cost for stock options is measured when options are issued. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 to require more prominent and more frequent (quarterly) disclosures in financial statements of the effects of stock-based compensation. SFAS 148 is effective for fiscal years ending after December 15, 2002. AEP does not currently intend to adopt the fair value based method of accounting for stock options.

In November 2002, the FASB issued an Invitation to Comment, "Accounting for Stock-Based Compensation: A Comparison of FASB Statement No. 123, *Accounting for Stock-Based Compensation*, and Its Related Interpretations, and IASB Proposed IFRS, *Share-Based Payment.*" The FASB plans to make a decision in the first quarter of 2003 whether it will begin a more comprehensive reconsideration of the accounting for stock options. This may include revisiting the decision in SFAS 123 allowing companies to disclose the pro forma effects of the fair value based method rather than requiring recognition of the fair value of employee stock options as an expense.

In January 2003, the FASB issued FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46) which changes the requirements for consolidation of certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. This new guidance is an interpretation of Accounting Research Bulletin (ARB) No. 51, "Consolidated Financial Statements". The initial recognition and initial measurement provisions of FIN 46 for all enterprises with variable interests in variable interest entities created after January 31, 2003, shall apply the provisions of this Interpretation to those entities immediately. A public entity with variable interests in variable interest entities created before February 1, 2003 shall apply the provisions of this Interpretation no later than the beginning of the first interim or annual reporting period beginning after June 15, 2003.

If it is reasonably possible that an enterprise will consolidate or disclose information about a variable interest entity when this Interpretation becomes effective, the enterprise shall disclose the following information in all financial statements initially issued after January 31, 2003, regardless of the date on which the variable interest entity was created:

a. The nature, purpose, size, and activities of the variable interest entity
b. The enterprise's maximum exposure to loss as a result of its involvement with the variable interest entity

AEP believes it is reasonably possible that it will be required to consolidate identified variable interest entities as a result of this new guidance. See Notes 9, 22, 23 and 26 for additional disclosures relating to AEP's variable interest entities.

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 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. In April 2002 the Ohio Supreme Court denied recovery of the final year of the GRT.

In October 2001 TCC reacquired $101 million of pollution control bonds in advance of their maturity. Since these pollution control bonds were used to finance unregulated generation assets, a loss of $2 million after-tax was recorded. The Company had no extraordinary items in 2002.

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

	Year Ended December 31,		
	2002	2001	2000
	(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
Loss on Reacquired Debt (Net of Tax of $1 Million in 2001)	-	(2)	-
Extraordinary Items	$ -	$(50)	$(35)

Cumulative Effect of Accounting Change - SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized and be tested annually for impairment. The implementation of SFAS 142 resulted in a $350 million net transitional loss for our U.K. and Australian operations and is reported in the Consolidated Statements of Operations as a cumulative effect of accounting change (see Note 3 for further details).

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 certain option-type contracts and forward contracts in electricity can qualify for the normal purchase or sale exclusion.

For AEP, the effect of initially adopting the DIG guidance at July 1, 2001 was a favorable earnings mark-to-market effect of $18 million, net of tax of $2 million. It was reported as a cumulative effect of an accounting change on the consolidated statements of operations.

3. Goodwill and Other Intangible Assets:

As described in our Significant Accounting Policies footnote, we adopted the provisions of SFAS 141 effective July 1, 2001. SFAS 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001 and established new standards for the recognition of certain identifiable intangible assets, separate from goodwill. Business combinations initiated after June 30, 2001 (see Note 12 for details) are accounted for utilizing SFAS 141.

SFAS 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, but instead tested for impairment at least annually. SFAS 142 required a two-step impairment test for goodwill. The first step was to compare the carrying amount of the reporting unit's assets to the fair value of the reporting unit. If the carrying amount exceeded the fair value then the second step was required to be completed, which involves allocating the fair value of the reporting unit to each asset and liability, with the excess being implied goodwill. The impairment loss is the amount by which the recorded goodwill exceeds the implied goodwill. We were required to complete a "transitional" impairment test for goodwill as of the beginning of the fiscal year in which the statement was adopted. This transitional impairment test required that we complete step one of the goodwill impairment test within six months from the date of initial adoption, or June 30, 2002. In the first quarter 2002, we completed the transitional impairment test of our goodwill related to our domestic operations and our indefinite lived intangible assets and concluded that those assets were not impaired.

In the second quarter 2002, we completed testing for goodwill impairment on our U.K. and Australian retail electricity and supply operations. The fair values of our U.K. and Australian retail electricity and supply operations were estimated using a combination of market values based on recent market transactions and cash flow projections. As a result of this testing, we determined that we had a net transitional impairment loss of $350 million, which is reported in the Consolidated Statements of Operations as a Cumulative Effect of Accounting Change.

SFAS 142 also requires that intangible assets with finite useful lives be amortized over their respective estimated lives to the estimated residual values. In accordance with SFAS 142, for all business combinations initiated before July 1, 2001, we amortized goodwill and intangible assets with indefinite lives through December 2001, and then ceased amortization. The goodwill associated with those business combinations with acquisition dates before July 1, 2001 was amortized on a straight-line basis generally over 40 years except for the portion of goodwill associated with gas trading and marketing activities, which was amortized on a straight-line basis over 10 years. Also, in accordance with SFAS 142, for all business combinations with acquisition dates after June 30, 2001, we have not amortized goodwill and intangible assets with indefinite lives. Intangible assets with finite lives continue to be amortized over their respective estimated lives ranging from 5 to 10 years.

New reporting requirements imposed by SFAS 142 include the disclosures shown below.

Goodwill

The changes in the carrying amount of goodwill for the twelve months ended December 31, 2002 by operating segment are:

	Wholesale	Energy Delivery	Other	AEP Consolidated
		(in millions)		
Balance January 1, 2002	$340	$37	$15	$392
Goodwill acquired	2	-	-	2
Changes to Goodwill due to purchase price adjustments	181	-	-	181
Non-transitional impairment losses	(173)	-	(12)	(185)
Foreign currency exchange rate changes	6	-	-	6
Balance December 31, 2002	$356	$37	$ 3	$396

Accumulated amortization of goodwill was approximately $22 million and $25 million at December 31, 2002 and 2001, respectively. A decrease of $3 million related principally to the non-transitional impairment of goodwill on Gas Power Systems (see Note 13.a).

The transitional impairment loss related to SEEBOARD and CitiPower goodwill, which is reported as a cumulative effect of an accounting change, is excluded from the above schedule. Under SFAS 144, the assets of SEEBOARD and CitiPower, including goodwill and acquired intangible assets no longer subject to amortization, are reported as Assets of Discontinued Operations in the Consolidated Balance Sheets. See Note 12 related to the sale of SEEBOARD and CitiPower.

Changes to goodwill due to purchase price adjustments of $181 million was primarily due to purchase price adjustments related to our acquisition of U.K. Generation. The purchase price adjustments also include adjustments related to the acquisition of Houston Pipe Line Company, MEMCO, Nordic Trading and AEP Coal (see Note 12).

In the first quarter of 2002, AEP recognized a goodwill impairment loss of $12 million for all goodwill related to the acquisition of Gas Power Systems (see Note 13.a).

In the fourth quarter of 2002, AEP prepared its annual goodwill impairment tests. The fair values of the operations were estimated using cash flow projections. There were no goodwill impairments as a result of the annual goodwill impairment tests. However, in the fourth quarter, AEP recognized goodwill impairment losses totaling $173 million related to impairment studies performed on the U.K. Generation assets ($166 million), AEP Coal ($3 million), and Nordic Trading ($4 million). These goodwill impairment studies were triggered by the SFAS 144 asset impairment losses recognized on these operations in the fourth quarter (refer to Note 13). The fair values of these operations were estimated using cash flow projections.

The following tables show the transitional disclosures to adjust reported net income (loss) and earnings (loss) per share to exclude amortization expense recognized in prior periods related to goodwill and intangible assets that are no longer being amortized.

Net Income (Loss)	Year Ended December 31, 2002	2001	2000
	(in millions)		
Reported Net Income (Loss)	$ (519)	$ 971	$267
Add back: Goodwill amortization (a)	-	39	39
Add back: Amortization for intangibles with indefinite lives under SFAS 142 (b)	-	8	9
Adjusted Net Income (Loss)	$ (519)	$1,018	$315

Earnings (Loss) Per Share (Basic and Dilutive)	Twelve Months Ended December 31, 2002	2001	2000
Reported Earnings (Loss) per Share	$(1.57)	$3.01	$0.83
Add back: Goodwill amortization (c)	-	0.12	0.12
Add back: Amortization for intangibles with indefinite lives under SFAS 142 (d)	-	0.02	0.03
Adjusted Earnings (Loss) per Share	$(1.57)	$3.15	$0.98

(a) This amount includes $34 million and $37 million in 2001 and 2000 related to Seeboard and CitiPower amortization expense included in Discontinued Operations on the Consolidated Statements of Operations.

(b) The amounts shown for 2001 and 2000 relate to CitiPower amortization expense included in Discontinued Operations on the Consolidated Statements of Operations.

(c) This amount includes $0.10 and $0.11 in 2001 and 2000 related to Seeboard and CitiPower amortization expense included in Discontinued Operations on the Consolidated Statements of Operations.

(d) The amounts shown for 2001 and 2000 relate to CitiPower amortization expense included in Discontinued Operations on the Consolidated Statements of Operations.

Acquired Intangible Assets

Acquired intangible assets subject to amortization are $37 million at December 31, 2002 and $33 million at December 31, 2001, net of accumulated amortization. The gross carrying amount, accumulated amortization and amortization life by major asset class are:

		December 31, 2002		December 31, 2001	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)	(in millions)		(in millions)	
Dolet Hills Advanced Royalties	10	$35	$5	$35	$2
Less: Adjustment Due to Purchase Price Reallocation		6	1	-	-
Trade name and Administration of Contracts	7	2	-	-	-
Unpatented Technology	10	10	-	-	-
Totals		$41	$4	$35	$2

Amortization of intangible assets was $2 million for the twelve months ended December 31, 2002. Estimated aggregate amortization expense is $4 million for each year 2003 through 2008.

AEP's acquired intangible assets no longer subject to amortization were comprised of retail and wholesale distribution licenses for CitiPower operating franchises. The licenses were being amortized on a straight-line basis over 20 and 40 years for the retail and wholesale licenses, respectively. In accordance with SFAS 144, the assets of CitiPower, including acquired intangible assets no longer subject to amortization, are reported as Assets of Discontinued Operations on one line in the Consolidated Balance Sheets. See Note 12 related to the sale of CitiPower.

4. 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.

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. Effective January 2003, the legal name of CSW was changed to AEP Utilities, Inc.

In connection with the merger, $10 million ($7 million after tax), $21 million ($14 million after tax) and $203 million ($180 million after tax) of non-recoverable merger costs were expensed in 2002, 2001 and 2000. Such costs included transaction and transition costs not recoverable from ratepayers. Also included in the merger costs were non-recoverable changes in control payments. Merger transaction and transition costs of $52 million recoverable from ratepayers were deferred pursuant to state regulator approved settlement agreements through December 31, 2002. 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, $8 million and $4 million for the years 2002, 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 - SWEPCo, TCC, TNC	$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.

See Note 9, "Commitments and Contingencies" for information on a court decision concerning the merger.

5. 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 nuclear operation and maintenance (O&M) costs 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,
- A freeze in base rates and fixed power supply costs recovery factors until January 1, 2004 for the Michigan jurisdiction

The amount of costs and deferrals charged to other operation and maintenance expenses were as follows:

	Year Ended December 31,		
	2002	2001	2000
	(in millions)		
Costs Incurred	$ -	$ 1	$ 297
Amortization of Deferrals	40	40	40
Charged to O&M Expense	$40	$41	$ 337

At December 31, 2002 and 2001, deferred O&M costs of $40 million and $80 million, respectively, remained in Regulatory Assets to be amortized through 2003. Also pursuant to the settlement agreements, accrued fuel-related revenues of $38 million were amortized as a reduction of revenues in each of 2002, 2001 and 2000. At December 31, 2002 and 2001, fuel-related revenues of $37 million and $75 million, respectively, were included in Regulatory Assets and will be amortized through December 31, 2003 for both jurisdictions.

The amortization of O&M 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 O&M costs and fuel-related revenue deferrals is approximately $78 million.

6. Rate Matters:

Texas Fuel -Prior to the start of retail competition in ERCOT on January 1, 2002, fuel recovery for Texas utilities was a multi-step procedure. When fuel costs changed, utilities filed with the PUCT for authority to adjust fuel factors. If a utility's prior fuel factors resulted in material over-recovery or under-recovery of fuel costs, the utility would also request a refund or surcharge factor to refund or collect those amounts. While fuel factors were intended to recover fuel costs, final settlement of these amounts was subject to reconciliation and approval by the PUCT.

Fuel reconciliation proceedings determine whether fuel costs incurred 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 costs in the Texas jurisdiction after 2001 is no longer subject to PUCT review and reconciliation. During 2002 TCC and TNC filed final fuel reconciliations with the PUCT to reconcile their fuel costs through the period ended 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. See discussion of TCC and TNC final fuel reconciliations below.

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 TNC's service territory are in SPP. SWEPCo's existing Texas 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 TNC fuel factors in the SPP area will be based upon the price-to-beat fuel factors offered by the retail electric provider in the ERCOT portion of TNC's service territory. TNC transferred its SPP customers to Mutual Energy SWEPCo effective December 1, 2002. TNC filed in 2002 with the PUCT to determine the most appropriate method to reconcile fuel costs in TNC's SPP area and a decision is expected by mid 2003.

Under Texas restructuring, customer choice to select a retail electric provider began January 1, 2002. Sales to customers using 1 MW or less are at fixed base rates during a transition period from 2002 through 2006. As discussed in Note 12 "Acquisitions, Dispositions and Discontinued Operations", AEP sold its Texas retail electric providers (REP) and their retail customers in December 2002.

The former AEP subsidiaries serving as REPs for the ERCOT area filed with the PUCT in May 2002 to increase the fuel portion of their price-to-beat rate in compliance with the Texas Restructuring Legislation and the PUCT's rules. The Texas legislation provides for the adjustment of the fuel portion of the rate up to twice annually to reflect significant changes in the market price of natural gas and purchased energy used to serve retail customers using NYMEX natural gas prices. On July 15, 2002, the PUCT required further hearings to reconsider the validity of their existing rules for fuel factor adjustments. On July 24, 2002, the Texas REPs filed a petition with the District Court seeking an injunction commanding the PUCT to proceed to a final order based on the existing rules and prohibiting the PUCT from conducting a remand proceeding. The District Court issued an order on August 9, 2002 requiring the PUCT to comply with the existing rules. On August 26, 2002, the PUCT issued an order approving a 22% increase to the fuel portion of the price-to-beat rates effective immediately for both REPs. The PUCT order approving the 22% increase has been appealed by parties opposing the price-to-beat adjustment. With the sale of the REPs to Centrica in December 2002, Centrica is responsible for these appeals. Any adverse ruling from the appeal could impact TCC and TNC by requiring refunds for the time period AEP served the retail customers prior to the sale to Centrica (January 2002 to December 2002).

TCC Fuel Reconciliation – In December 2002 TCC filed with the PUCT to reconcile fuel costs and to defer its over-recovery of fuel for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 1998 through December 2001 will be the final fuel reconciliation. At December 31, 2001, the over-recovery balance for TCC was $63.5 million including interest. During the reconciliation period, TCC incurred $1.6 billion of eligible fuel and fuel-related expenses. Recommendations from intervening parties are expected in April 2003 with hearings scheduled in May 2003. A final order is expected in late 2003. An adverse ruling from the PUCT could have a material impact on future results of operations, cash flows and financial condition. Additional information regarding the 2004 true-up proceeding for TCC can be found in Note 8 "Customer Choice and Industry Restructuring".

TNC Fuel Reconciliation – In June 2002 TNC filed with the PUCT to reconcile fuel costs and to defer any unrecovered portion applicable to retail sales within its ERCOT service area for inclusion in the 2004 true-up proceeding. This reconciliation for the period of July 2000 through December 2001 will be the final fuel reconciliation for TNC's ERCOT service territory. At December 31, 2001, the under-recovery balance associated with TNC's ERCOT service area was $27.5 million including interest. During the reconciliation period, TNC incurred $293.7 million of eligible fuel costs serving both ERCOT and SPP retail customers. TNC also requested authority to surcharge its SPP customers. TNC's SPP customers will continue to be subject to fuel reconciliations until competition begins in SPP. The under-recovery balance at December 31, 2001 for TNC's service within SPP was $0.7 million including interest.

In October 2002 the filing was split into two phases for hearing purposes. The first phase examined all components of the filing except for AEP trading activities and the associated margins that flow back to customers as an offset to fuel costs consistent with the PUCT - approved Texas merger settlement. Intervenors filed testimony in the first phase recommending that up to $25 million of TNC's requested retail eligible fuel recovery be disallowed and hearings were held on October 23, 2002. TNC disputed the recommendations. On October 21, 2002, the PUCT Staff and Office of Public Utility Counsel (OPC) filed a joint Motion for Summary Decision related to the second phase issue and requested that approximately $18.5 million of TNC's retail eligible fuel recovery be disallowed without a hearing. On November 8, 2002, the administrative law judges (ALJs) in the case denied the motion. The intervenors filed testimony on October 29, 2002 in the second phase recommending that up to $34 million of TNC's requested retail eligible fuel recovery be disallowed. The intervenors recommended disallowance includes the amount sought in the October 21 Motion for Summary Decision. The total intervenor recommended retail disallowance is approximately $59 million. Hearings for the second phase were held on November 13-14, 2002. On February 3, 2003, TNC filed a motion to reopen the evidentiary record and include a decrease to retail eligible fuel costs of $1.3 million, including interest, to reflect final resettlement revenues and expenses from ERCOT for the period August through December 2001 (see discussion in Fuel and Purchased Power below). The PUCT is expected to issue a final order in this case by mid 2003. An adverse ruling from the PUCT could have a material impact on future results of operations, cash flows and financial condition.

ERCOT Over-scheduling - ERCOT began serving as a central control center for all of ERCOT at the end of July 2001 when ERCOT became a single control area. Qualified scheduling entities (QSE) schedule loads and resources for ERCOT market participants including power generation companies and retail electric providers. In August 2001 ERCOT incurred substantial costs for managing transmission in its north zone. The costs incurred by ERCOT to manage congestion are shared by all ERCOT QSEs. In late 2001, the PUCT initiated an investigation of the impact of scheduling of electric loads and resources by QSEs during August 2001. The PUCT's investigation determined that a substantial amount of the congestion charges were the result of QSEs, including AEP's QSE, scheduling more resources than required to meet their actual load requirements in the ERCOT north zone. AEP's QSE over-scheduled resources due to an error in the allocation of estimated load requirements between ERCOT congestion zones. Pursuant to the PUCT's investigation, QSEs, including AEP's QSE, agreed to a settlement that provides for the refund of payments received for adjusting resource schedules for congestion. The settlement was approved by the PUCT in November 2002. The settlement recognizes that the scheduling errors were associated with the start up of the ERCOT competitive market. AEP's QSE paid $3.2 million to ERCOT and received $1.7 million from ERCOT in congestion refunds for a net payment of $1.5 million. Payments were assigned to TNC and the refunds were allocated to TCC and TNC. TNC incurred a net cost of $2.8 million and TCC received a refund of $1.3 million. The TNC payment and TCC refund have been reflected in the final fuel reconciliation filings for each company. However, intervening parties have objected to the inclusion of the TNC payment in its final fuel reconciliation. Recommendations from intervening parties in the TCC proceeding are not expected until April 2003. An adverse ruling from the PUCT could impact future results of operations, cash flows and financial condition.

Texas Transmission Rates – On June 28, 2001, the Supreme Court of Texas ruled that the transmission pricing mechanism created by the PUCT in 1996 and used for the period January 1, 1997 through August 31, 1999 was invalid. The court upheld an appeal filed by unaffiliated Texas utilities that the PUCT exceeded its statutory authority to set such rates during that period. TCC and TNC 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 unfavorable impact on results of operations and cash flows for TCC and TNC.

FERC Wholesale Fuel Complaints – In May 2000 certain TNC wholesale customers filed a complaint with FERC alleging that TNC had overcharged them through the fuel adjustment clause for certain purchased power costs related to 1999 unplanned outages at TNC's Oklaunion generation station. In November 2001 certain TNC wholesale customers filed an additional complaint with the FERC asserting that since 1997 TNC 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 TNC 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. In response to the November 2001 complaint, negotiations to settle the complaint and revise the contracts are continuing. In March 2002 TNC recorded a provision for refund of $2.2 million before income taxes. The actual refund and final resolution of this matter could differ materially from this estimate and may have a negative impact on future results of operations, cash flow and financial condition.

FERC Transmission Rates – In November 2001 FERC issued an order resulting from a remand by an appeals court of a tariff compliance filing order issued in 1998 that had been appealed by certain customers. The order required PSO, SWEPCo, TCC and TNC to submit revised open access transmission tariffs and calculate and issue refunds for overcharges from January 1, 1997. In July 2002 FERC approved a revised open access transmission tariff and refunds of $1.3 million were issued.

Fuel and Purchased Power - PSO had under-recovered fuel costs of $75.7 million at December 31, 2002, representing fuel and purchased power costs recorded but not yet collected from retail customers in Oklahoma. The first significant item causing the under-recovery is approximately $44 million in reallocation of purchased power costs for periods prior to January 1, 2002, as described below. The other significant item impacting the under-recovered fuel costs are natural gas price increases that were not expected when PSO set its quarterly factors during 2002. The Corporation Commission of the State of Oklahoma (OCC) is currently reviewing the reasons for the large under-recovered balance.

The AEP West electric operating companies' power is dispatched real-time on an economic basis and is later allocated among the AEP West electric operating companies using the Interchange Cost Reconstruction (ICR) system based on dispatch information from internal and external sources. ICR is designed to allocate the cost of power under the terms and conditions of the AEP West Operating Agreement. During 2002, two ICR adjustments were made. The adjustments were related to a 2002 true-up and a reallocation of years prior to 2002.

During the third quarter of 2002, AEP reallocated purchased power costs among the four AEP West electric operating companies for the periods prior to January 1, 2002 (the ICR Adjustments). The effects of the reallocation on pretax income were insignificant to PSO and TCC and increased pre-tax income at SWEPCo and TNC by $2.4 million and $1.9 million, respectively.

The formation of the ERCOT single control zone increased the need for data estimation and true-up which has resulted in extended true-up periods associated with allocations being performed on estimated data. ERCOT can make adjustments to companies' settlements for up to six months. A true-up process for 2002 was completed and recorded in the fourth quarter of 2002 resulting in insignificant changes in PSO's and SWEPCo's pre-tax income. TCC's pre-tax income was reduced by $3.7 million and TNC's pre-tax income was increased by $4.8 million. As ERCOT notifies the companies of further adjustments, they will be recorded.

PSO implemented new fuel rates in December 2002 following the OCC's review and approval.

The new fuel factors were designed to recover estimated fuel costs for the next three months and to begin recovery of the under-recovered amount. Recovery of the under-recovered amount is expected to occur over several months and is subject to OCC review and approval.

For SWEPCo, the true-up process described above and the ICR Adjustments resulted in a net increase in fuel costs recoverable from customers of $8 million included in Regulatory Assets on the Consolidated Balance Sheets. The amount is recoverable from customers pursuant to the applicable fuel recovery mechanisms and review of the state regulatory commissions in Arkansas, Louisiana and Texas.

To the extent the OCC and/or the AEP West Commissions regulating SWEPCo do not permit recovery of the revised fuel and purchased power costs, there could be an adverse effect on results of operations and cash flows.

PSO Rate Review – In February 2003, the Director of the OCC filed an application requiring PSO to file all documents necessary for a general rate review before August 1, 2003. Management is unable to predict the result of this review as the documents and data have not been assembled.

Louisiana Compliance Filing - On October 15, 2002, SWEPCo filed with the Louisiana Public Service Commission (LPSC) detailed financial information typically utilized in a revenue requirement filing, including a jurisdictional cost of service. This filing was required by the LPSC as a result of their order approving the merger between AEP and CSW. The LPSC's merger order also provides that SWEPCo's base rates are capped at the present level through mid 2005. The filing indicates that SWEPCo's current rates should not be reduced. If the LPSC disagrees with our conclusion, they could order SWEPCo to file all documents for a full cost of service revenue requirement review in order to determine whether SWEPCo's capped rates should be reduced which would adversely impact results of operations and cash flows.

FERC Long-term Contracts - In September 2002 the FERC voted to hold hearings to consider requests from certain wholesale customers located in Nevada and Washington to break long-term contracts which the customers allege are "high-priced". At issue are long-term contracts entered during the California energy price spike in 2000 and 2001. The complaints allege that AEP sold power at unjust and unreasonable prices. The FERC delayed hearings to allow the parties to hold settlement discussions. In January 2003 the FERC settlement judge assigned to the case indicated that the parties' settlement efforts were not progressing and he recommended that the complaint be placed back on the schedule for a hearing. In February 2003 AEP and one of our customers agreed to terminate their contract with the customer withdrawing its FERC complaint.

In the similar complaint, a FERC administrative law judge (ALJ) ruled in favor of AEP and dismissed in December 2002 a complaint filed by two Nevada utilities. In 2000 and 2001, AEP agreed to sell power to the utilities for future delivery. In late 2001 the utilities filed complaints that the prices for power supplied under those contracts should be lowered because the market for power was allegedly dysfunctional at the time such contracts were entered. The ALJ rejected the utilities' complaint, held that the markets for future delivery were not dysfunctional, and that the utilities' had failed to demonstrate that the public interest required that changes be made to the contracts. The ALJ's order is preliminary and is subject to review by the FERC. The FERC will likely rule on the ALJ's order in 2003. Management is unable to predict the outcome of these proceedings or their impact on results of operations.

Environmental Surcharge Filing – In September 2002 KPCo filed with the KPSC to revise its environmental surcharge tariff to recover the cost of emissions control equipment being installed at Big Sandy Plant. See NOx Reductions in Note 9 "Commitments and Contingencies".

The surcharge request, as filed, would increase annual revenues by approximately $21 million and must be approved by the KPSC before its inclusion in customers' bills. If the KPSC does not approve an increase in the environmental surcharge, results of operations and cash flows would be negatively impacted.

7. Effects of Regulation:

In accordance with SFAS 71 the consolidated financial statements include regulatory assets (deferred expenses) and regulatory liabilities (deferred revenues) recorded in accordance with regulatory actions in order to match expenses and revenues from cost-based rates in the same accounting period. Regulatory assets are expected to be recovered in future periods through the rate-making process and regulatory liabilities are expected to reduce future cost recoveries. Among other things, application of SFAS 71 requires that the AEP System'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 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 West Virginia 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 West Virginia 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. These assets are classified as "transition regulatory assets". As discussed in Note 8, "Customer Choice and Industry Restructing" 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. These assets are also classified as "transition regulatory assets." The Texas jurisdiction generation-related regulatory assets that are eligible for recovery through securitization have been classified as "regulatory assets designated for or subject to securitization." See Note 8 "Customer Choice and Industry Restructuring" for further details.

AEP's recognized regulatory assets and liabilities are comprised of the following at:

	December 31, 2002	December 31, 2001
	(in millions)	
Regulatory Assets:		
Amounts Due From Customers For Future Income Taxes	$ 791	$ 814
Transition Regulatory Assets	743	847
Regulatory Assets Designated for or Subject to Securitization	336	959
Texas Wholesale Clawback (a)	262	-
Deferred Fuel Costs	143	139
Unamortized Loss on Reacquired Debt	83	99
Cook Plant Restart Costs	40	80
DOE Decontamination and Decommissioning Assessment	26	31
Other	264	193
Total Regulatory Assets	$2,688	$3,162
Regulatory Liabilities:		
Deferred Investment Tax Credits	$ 455	$ 491
Texas Retail Clawback (a)	66	-
Other	419	393
Total Regulatory Liabilities	$ 940	$ 884

(a) See "Texas Restructuring" section of Note 8.

At December 31, 2002 $1,870 million of Regulatory Assets are not earning a return.

- $641 million of the total $791 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 $743 million are not earning a return and had the following recovery periods.
    - $419 million five years
    - $205 million six years
    - $119 million nine years
- Deferred fuel costs of $143 million includes $113 million that was not earning a return and had the following recovery periods:
    - $76 million that fluctuates month to month and has no fixed recovery period.
    - $37 million one year
- Cook plant restart costs of $40 million does not earn a return and has a recovery period of one year.
- Unamortized loss on reacquired debt includes $43 million not earning a return and ranges

from one to thirty-six years recovery period.

- The balance of $289 million not earning a return is of varying natures and recovery periods.

8. Customer Choice and Industry Restructuring:

Customer choice allowing retail customers to select alternative generation suppliers began on January 1, 2001 in Ohio and on January 1, 2002 in Michigan, Virginia and in the ERCOT area of Texas. Customer choice in the SPP area of Texas, also scheduled to begin on January 1, 2002, was delayed by the PUCT. AEP's subsidiaries operate in both the ERCOT and SPP areas of Texas.

Implementation of legislation enacted in Arkansas, Oklahoma, and West Virginia to allow retail customers to choose their electricity supplier has been delayed or repealed. In 2001 Oklahoma delayed implementation of customer choice indefinitely. In February 2003 the Arkansas General Assembly passed legislation that repealed customer choice legislation, which is currently awaiting signature by the Governor of Arkansas. Before West Virginia's choice plan can be effective, tax legislation must be passed to continue consistent funding for state and local governments. No further legislation has been introduced related to restructuring in 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. At January 1, 2003, 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 provided 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 and approval of a transition plan for each electric utility company, changed the taxation of electric companies and addressed certain major transition issues including unbundling of rates and the recovery of stranded costs including regulatory assets and transition costs.

In 1999 CSPCo and OPCo filed transition plans. 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, 2002, the remaining amount of regulatory assets to be amortized as recovered was $375 million for OPCo and $205 million for CSPCo.

By provisions of the Ohio Act on 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 paid the excise tax based on gross receipts was 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 treated the tax payment as a prepaid expense and amortized it to expense during the privilege year.

The stipulation agreement also required the PUCO to consider implementation of a gross receipts tax credit rider as the parties could not reach an agreement. Following a hearing on the gross receipts tax issue, 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. On April 3, 2002, the Ohio Supreme Court rejected the companies' arguments and affirmed the PUCO's order which established the effective date of tax credit riders in rates. This ruling had no impact on 2002 results of operations as the companies had recorded an extraordinary loss of $48 million (net of tax of $20 million) in 2001.

On June 27, 2002, the Ohio Consumers' Counsel, Industrial Energy Users – Ohio and American Municipal Power – Ohio filed a complaint with the PUCO alleging that CSPCo and OPCo have violated the PUCO's orders regarding implementation of their transition plan and violated other applicable law by failing to participate in an RTO.

The complainants seek, among other relief, an order from the PUCO suspending collection of transition charges by CSPCo and OPCo until transfer of control of their transmission assets has occurred, pricing standard offer electric generation effective January 1, 2006 at the market price used by the companies in their 1999 transition plan filings to estimate transition costs and imposing a $25,000 per company forfeiture for each day AEP fails to comply with its commitment to transfer control of transmission assets to an RTO.

Due to the FERC's reversal of its previous approvals of our RTO filings, CSPCo and OPCo have been delayed in the implementation of their RTO participation plans. We continue to pursue integration of CSPCo, OPCo and other AEP East companies into PJM. In this regard on December 19, 2002, the companies filed an application with PUCO for approval of the transfer of functional control over certain of their transmission facilities to PJM. Management is unable to predict the timing of FERC's final approval of RTOs, the timing of an RTO being operational or the outcome of these proceedings before the PUCO.

In October 2002 the PUCO initiated an investigation of the financial condition of Ohio's regulated public utilities. The PUCO's goal is to identify measures available to the PUCO to ensure that the regulated operations of Ohio's public utilities are not impacted by adverse financial consequences of parent or affiliate company unregulated operations and take appropriate corrective action, if necessary. The utilities and other interested parties were requested to provide comments and suggestions by November 12, 2002, with reply comments by November 22, 2002, on the type of information necessary to accomplish the stated goals, the means to gather the required information from the public utilities and potential courses of action that the PUCO could take. Management is unable to predict the outcome of the PUCO's investigation or its impact on results of operations and business practices, if any.

Virginia Restructuring – In Virginia, choice of electricity supplier for retail customers began on January 1, 2002 under its restructuring law. Presently, APCo continues to service all its previous customers under capped rates. A finding by the Virginia SCC that an effective competitive market exists would be required to end the transition period prior to its scheduled end on June 30, 2007.

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. 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.

In July 2002 APCo filed with the Virginia SCC requesting an increase in fuel rates effective January 1, 2003. A public hearing was held on September 23, 2002 related to this filing. On November 8, 2002, a decision was issued in this proceeding approving an annual increase of approximately $24 million.

The Virginia restructuring law also required filings to be made that outline the functional separation of generation from transmission and distribution and a rate unbundling plan. In January 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 did not and will not collect a wires charge in 2002 or 2003, respectively. The settlement agreements and related Virginia SCC order addressed functional separation leaving decisions related to corporate separation for later consideration.

Texas Restructuring – In preparation for the start of competition in Texas, CPL, SWEPCo, and WTU, the integrated electric utility companies operating in Texas, were required to make PUCT filings and legal and operational changes to their business. AEP formed new subsidiaries, Mutual Energy CPL L.P. and Mutual Energy WTU L.P., to act as retail electric providers (REP) in Texas beginning on January 1, 2002, the effective date of customer choice in Texas. The CPL and WTU names continued to be used by the registrant subsidiaries which owned the generation, transmission and distribution assets located in the ERCOT areas of Texas and WTU's entire operations in SPP throughout most of 2002. In December 2002 WTU transferred its SPP retail customers to Mutual Energy SWEPCO L.P. AEP sold the new subsidiaries that serve ERCOT retail customers to Centrica in December 2002, along with the Central Power and Light and West Texas Utilities brand names. CPL and WTU changed their names to AEP Texas Central Company (TCC) and AEP Texas North Company (TNC), respectively.

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 TNC's service territory are located in the SPP. TCC 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;
- provides for an earnings test for each of the years 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 and;
- provides for a 2004 true-up proceeding to quantify and reconcile the amount of stranded costs, final fuel balances, net regulatory assets, certain environmental costs, accumulated excess earnings, excess of price-to-beat revenues over market prices subject to certain conditions and limitations (Retail clawback), and the difference between the price of power obtained through the legislatively-mandated capacity auctions and the power costs used in the PUCT's ECOM model for 2002 and 2003 (Wholesale clawback) and other issues.

Under the Texas Legislation, electric utilities were required to submit a plan to structurally unbundle business activities into a retail electric provider, a power generation company and a transmission and distribution (T&D) utility. In 2000 SWEPCo, TCC and TNC filed their business separation plans with the PUCT. The PUCT approved the plans for TCC and TNC but determined that competition in the SPP areas of Texas should be delayed indefinitely and abated SWEPCo's plan.

Operations for TCC and TNC have been functionally separated consistent with the approved plans. The delivery of electricity in ERCOT continues to be the responsibility of TCC and TNC at regulated prices.

Texas Legislation provides electric utilities an opportunity to recover regulatory assets and stranded costs resulting from the unbundling of the T&D utility from the generation facilities. Stranded costs are the difference between regulatory net book value of generation assets and the market value of the assets based on one of several methodologies authorized by the Texas Legislation. Stranded costs can be refinanced through securitization (a financing structure designed to provide lower financing costs than are available through conventional financings).

In 1999 TCC 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). TCC issued its securitization bonds in February 2002. The annual cost of the bonds are recovered through a PUCT approved transition charge in distribution rates.

TCC 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 were 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 TCC's stranded costs was negative $615 million. TCC disagreed with the ruling (see discussion of appeal ruling below). The ruling indicated that TCC's costs were below market after securitization of regulatory assets. The final amount of TCC's stranded costs including regulatory assets and ECOM will be established by the PUCT in the 2004 true-up proceeding. If TCC'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 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, stock valuation or the use of an ECOM model.

TCC decided to obtain a market value of generating assets for purposes of determining stranded costs for the 2004 true-up proceeding and filed a plan of divestiture with the PUCT in December 2002 seeking approval of a sales process for all of its generating facilities. Such sales quantify the actual stranded costs. The amount of stranded costs under this market valuation methodology will be the amount by which net book value of TCC's generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets as measured by the net proceeds from the sale of the assets. It is anticipated that any such sale will result in significant stranded costs for purposes of the 2004 true-up proceeding. The filing included a request for the PUCT to issue a declaratory order that TCC's 25% ownership interest in its nuclear plant, STP, can be sold to value stranded costs. Intervenors to this proceeding, including the PUCT Staff, have made filings to dismiss TCC's filing claiming that the PUCT does not have the authority to issue a declaratory order. The intervenors also argued that the proper time to address the sales process is after the plants are sold during the 2004 true-up proceeding. Since the bidding process is not expected to be completed before mid 2004, TCC requested that the 2004 true-up proceeding be scheduled after completion of the divestiture of the generating assets.

Texas Legislation also requires that electric utilities and their affiliated power generation companies (PGC) sell at auction in 2002 and 2003 at least 15% of the PGC's Texas jurisdictional installed generation capacity in order to promote competitiveness in the wholesale market through increased availability of generation and liquidity. Actual market power prices received in the state mandated auctions will replace the PUCT's earlier estimates of those market prices used in the ECOM model to calculate the stranded cost for the 2004 true-up proceeding.

The decision to determine stranded costs using market prices, instead of using the PUCT's ECOM model estimates, enabled TCC to record a $262 million regulatory asset and related revenues which represents the quantifiable amount of stranded costs for the year 2002 related to the wholesale prices. Prior to the decision to pursue a sale of TCC's generating assets, the PUCT's ECOM estimate prohibited the recognition of the regulatory assets and revenues as there was no way to quantify stranded costs. As discussed above, a defined process is required in order to determine the amount of stranded costs related to generation facilities for the 2004 true-up proceedings. TCC's plan of divestiture filed with the PUCT during December 2002 provided such a process.

When the divestiture and the 2004 true-up process are completed, TCC will securitize any stranded costs which exceed current securitized amounts. The annual costs of securitization will be recovered through a non-bypassable rate surcharge by the regulated T&D utility over the life of the securitization bonds. Any stranded costs and other true-up amounts not recovered through the sale of securitization bonds may be recovered through a separate non-bypassable competitive transition charge to T&D utility customers.

The Texas Legislation provides for an earnings test each year 1999 through 2001 and requires PUCT approval of the annual earnings test calculation.

The PUCT issued final orders for the 1999 earnings test in February 2001 and for the 2000 earnings test in September 2001. The 1999 excess earnings were none for SWEPCo, $24 million for TCC and $1 million for TNC. Excess earnings for 2000 were $1 million for SWEPCo, $23 million for TCC and $17 million for TNC. Adjustments were recorded in results of operations as the orders were received.

The PUCT issued its final order for the 2001 earnings test in December 2002. An estimate of 2001 excess earnings of $8 million for TCC, $2 million for SWEPCo and none for TNC had been recorded in 2001. Adjustments to reflect the PUCT staff's estimate of excess earnings ($2 million for SWEPCo, $0.7 million for TNC and none for TCC) were recorded prior to September 30, 2002. The PUCT's final order regarding 2001 excess earnings required only minor adjustments to prior estimates.

Due to TCC's and TNC's disagreement with the PUCT's final order for the 2000 excess earnings, the companies filed an appeal in district court in 2001 seeking judicial review of the PUCT's determination of excess earnings. The district court upheld the PUCT's order and the companies appealed that decision. A ruling on the appeal is expected in 2003.

On January 28, 2003, the TCC and TNC filed an appeal in District Court seeking judicial review of the PUCT order for the 2001 excess earnings.

The PUCT ruled that prior to the 2004 true-up proceeding, no adjustments would be made to the amount of stranded costs authorized by the PUCT to be securitized. Final stranded cost amounts and the treatment of excess earnings will be determined in the 2004 true-up proceeding. To the extent that the final 2004 true-up proceeding determines that TCC should recover additional stranded costs, the additional amount recoverable can also be securitized. The PUCT also ruled that estimated 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 TCC to reduce distribution rates by approximately $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. Since excess earnings amounts were expensed 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 TCC will have stranded costs in 2004. TCC has appealed the PUCT's refund of excess earnings to the Travis County District Court and, depending on the outcome of that appeal (and the final outcome of the rulemaking challenge discussed below), the PUCT may revise the treatment of excess earnings in the final calculation of the stranded cost balance. In the same appeal, TCC and certain unaffiliated parties also challenged various elements of the PUCT's order determining the estimated stranded costs of TCC, with the unaffiliated parties contending, among other things, that the entire $615 million of negative stranded costs should be refunded presently. Prior to the Court hearing on this issue, however, TCC agreed to give up its claims concerning errors in the calculation of the stranded cost estimate, while the unaffiliated parties agreed to give up claims that there should be a refund of negative stranded costs. The Travis County District Court subsequently heard oral arguments concerning the remaining issues in the appeal, but has not yet issued a decision. The PUCT's stranded cost estimate that is the subject of this appeal will be superceded by a final determination of stranded costs to be accomplished as part of the 2004 true-up proceeding.

In a separate appeal challenging the PUCT's substantive rule governing the 2004 true-up proceeding, the Texas Third Court of Appeals ruled in February 2003, that the Texas Legislation does not contemplate the refunding of negative stranded costs to customers. The Court of Appeals held that the PUCT was justified in using any negative stranded cost balance determined in the 2004 true-up proceeding only as an offset to prevent an over-recovery of stranded costs via securitization. In addition, the Court of Appeals ruled that negative stranded costs cannot be offset against other true-up balances, including final under-recovered fuel amounts. This ruling may be further appealed to the Supreme Court of Texas.

Beginning January 1, 2002, fuel costs are not subject to PUCT fuel reconciliation proceedings for TCC and TNC's ERCOT retail customers. Due to the delay of competition for SWEPCo's SPP area of Texas, SWEPCo continues to record and request recovery of fuel costs subject to Texas fuel proceedings. Final deferred fuel balances related to ERCOT customers of TCC and TNC at December 31, 2001 will be included in the 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.

Under the Texas Legislation, retail electric providers (REPs) associated with integrated utilities are required 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 the AEP REPs in TCC's and TNC's ERCOT area. Customers with a peak usage of more than 1000 KW are subject to market rates. The Texas Restructuring Legislation also provides that a REP associated with integrated utilities may request an adjustment of its fuel portion of the price-to-beat rate up to two times annually to reflect changes in market prices of fuel and purchased energy costs based upon changes in NYMEX gas prices.

As part of the 2004 true-up proceedings the price-to-beat rates charged by AEP REPs for 2002 and 2003 will be compared to the market rates for the same period. If market rates are lower, the excess of the price-to-beat, reduced by non-bypassable delivery charges, over the prevailing market prices must be returned to the distribution company, subject to a per customer maximum. During 2002, AEP provided for such potential liabilities at the maximum amount via a charge to revenues, and recorded a regulatory liability for TCC and TNC. These amounts were $52 million for TCC and $14 million for TNC.

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.

A Joint Stipulation approved by the WVPSC in 2000 in connection with an APCo base rate filing, allowed 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.

Management expects that the approved Joint Stipulation provides for the recovery of existing regulatory assets and other stranded costs.

In order for customer choice to become effective in WV, the WV Legislature needed to enact additional legislation to preserve the revenues of state and local government. In the subsequent two legislative sessions, which usually end in March each year, the West Virginia Legislature has not enacted the required legislation. Due to the lack of legislative activity, the WVPSC closed two proceedings related to electricity restructuring in the summer of 2002.

The two closed proceedings related to the respective dockets intended originally to determine whether West Virginia should deregulate the generation business, and to develop the WVPSC's Deregulation Plan and related rules to implement the Plan.

Management has reviewed these two proceedings and concluded that at this time it is not clear that APCo meets the requirements to reapply SFAS 71. Management will monitor developments to determine when it is appropriate to reapply SFAS 71 to APCo's generation business.

Arkansas Restructuring – In 1999 Arkansas enacted legislation to restructure its electric utility industry.

In February 2003 the Arkansas General Assembly passed legislation that repealed customer choice legislation, which is currently awaiting signature by the Governor of Arkansas.

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 resulted in AEP and certain subsidiaries discontinuing 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 resulted in recognition of extraordinary gains or losses. 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.

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 companies 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 – 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 December 31, 2002, none of I&M's customers have elected to change suppliers and no alternative electric suppliers are registered to compete in I&M's Michigan service territory.

Management has concluded that as of December 31, 2002 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.

9. Commitments and Contingencies:

Construction and Other Commitments - The AEP System has substantial construction commitments to support its operations. Aggregate construction expenditures for 2003-2005 for consolidated domestic and foreign operations are estimated to be $4.7 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. Certificates have been issued by both the West Virginia Public Service Commission and the Virginia State Corporation Commission authorizing construction and operation of the line. On December 31, 2002, the U.S. Forest Service issued a final environmental impact statement and record of decision to allow the use of federal lands in the Jefferson National Forest for construction of a portion of the line. We expect additional state and federal permits to be issued in the first half of 2003. Through December 31, 2002, we had invested approximately $51 million in this effort. The line is estimated to cost $287 million including amounts spent to date with completion scheduled in 2006. If the required permits are not obtained and the line is not constructed, the $51 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 for the AEP System. The contracts provide for periodic price adjustments and contain various clauses that would release the subsidiaries from their obligations under certain force majeure conditions.

The AEP System has unit contingent contracts to supply approximately 250 MW of capacity to unaffiliated entities through December 31, 2009. The commitment is pursuant to a unit power agreement requiring the delivery of energy only if the unit capacity is available.

Power Generation Facility – AEP has entered into agreements with Katco Funding L.P. (Katco) an unrelated unconsolidated special purpose entity. Katco has an aggregate financing commitment of $525 million and a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from a syndicate of banks. Katco was formed to develop, construct, finance and lease a power generation facility to AEP. Katco will own the power generation facility and lease it to AEP after construction is completed. The lease will be accounted for as an operating lease (see Note 22), therefore neither the facility nor the related obligations are reported on AEP's balance sheet. Payments under the operating lease are expected to commence in the first quarter of 2004. AEP will in turn sublease the facility to Dow Chemical Company (DOW), which will use the energy produced by the facility and sell excess energy. AEP has agreed to purchase the excess energy from DOW for resale. The use of Katco allows AEP to limit its risk associated with the power generation facility once the construction phase has been completed.

AEP is the construction agent for Katco, and is responsible for completing construction by December 31, 2003, subject to unforeseen events beyond AEP's control.

In the event the project is terminated before completion of construction, AEP has the option to either purchase the facility for 100% of project costs or terminate the project and make a payment to Katco for 89.9% of project costs.

The operating lease between Katco and AEP commences on the commercial operation date of the facility and continues until November 2006. The lease contains extension options subject to the approval of Katco, and if all extension options were exercised, the total term of the lease would be 30 years. AEP's lease payments to Katco are sufficient for Katco to make required debt payments and provide a return to the investors of Katco. At the end of each lease term, AEP may renew the lease at fair market value subject to Katco's approval, purchase the facility at its original construction cost, or sell the facility, on behalf of Katco, to an independent third party. If the facility is sold and the proceeds from the sale are insufficient to repay Katco, AEP may be required to make a payment to Katco for the difference between the proceeds from the sale and the obligations of Katco, up to 82% of the project's cost. AEP has guaranteed a portion of the obligations of its subsidiaries to Katco during the construction and post-construction periods.

As of December 31, 2002, project costs subject to these agreements totaled $360 million, and total costs for the completed facility are expected to be approximately $510 million. For the 30–year extended lease term, the lease rental 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 during the initial term calculated using the indexed LIBOR rate (1.38% at December 31, 2002). The Power Generation Facility collateralizes the debt obligation of Katco. AEP's maximum exposure to loss as a result of its involvement with Katco is 100% during the construction phase and up to 82% once the construction is completed. Maximum loss is deemed to be remote due to the collateralization.

It is reasonably possible that AEP will consolidate Katco in the third quarter of 2003, as a result of the issuance of FASB Interpretation No. 46 "Consolidation of Variable Interest Entities" (FIN 46). Upon consolidation, AEP would record the assets, liabilities, depreciation expense, minority interest and debt interest expense. AEP would eliminate operating lease expense. The sublease to DOW would not be affected by this consolidation.

OPCo has entered into a 30-year power purchase agreement for electricity produced by an unaffiliated entity's three-unit natural gas fired plant. The plant was completed in 2002 and the agreement will terminate in 2032. Under the terms of the agreement, OPCo has the option to run the plant until December 31, 2005 taking 100% of the power generated and making monthly capacity payments. The capacity payments are fixed through December 2005 at $1.2 million per month. For the remainder of the 30-year contract term, OPCo will pay the variable costs to generate the electricity it purchases (up to 20% of the plant's capacity).

Nuclear Plants – I&M owns and operates the two-unit 2,110 MW Cook Plant under licenses granted by the NRC. TCC 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 TCC 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 from customers 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. TCC 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. Under an industry-wide program insuring workers at nuclear facilities, I&M and TCC are also obligated for assessments of up to $6.2 million and $1.6 million, respectively, for potential claims. These obligations will remain in effect until December 31, 2007.

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. I&M 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 TCC which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The current Price-Anderson Act expired in August 2002. Its contingent financial obligations still apply to reactors licensed by the NRC as of its expiration date. It is anticipated that the Price-Anderson Act will be renewed with increased third party financial protection requirements for nuclear incidents.

Spent Nuclear Fuel 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 $224 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, 2002, funds collected from customers towards payment of the pre-April 1983 fee and related earnings thereon are in external funds and exceed the liability amount. TCC 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 using the prompt decontamination and dismantlement (DECON) method. 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 2002 and 2001 and $28 million in 2000.

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 DECON method. TCC estimates its portion of the costs of decommissioning STP to be $289 million in 1999 nondiscounted dollars. TCC 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 2002 and 2001 I&M deposited in its decommissioning trust an additional $12 million each year 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 including interest, unrealized gains and losses and expenses of the trust funds are recorded in other operation expense for Cook Plant. For STP, nuclear decommissioning costs are recorded in other operation expense, interest income of the trusts are recorded in nonoperating income and interest expense of the trust funds are included in interest charges.

On the Consolidated Balance Sheets, nuclear decommissioning trust assets are included in Other Assets and a corresponding nuclear decommissioning liability is included in Other Noncurrent Liabilities. The decommissioning liability for both nuclear plants combined totals $719 million and $699 million at December 31, 2002 and 2001, respectively.

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 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 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.

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

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 the 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.

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 imposed emissions reduction requirements comparable to the NOx Rule beginning May 1, 2003, for most of AEP's coal-fired generating units. Affected utilities, including certain AEP operating companies, 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 subsidiaries and other utilities requested that the D.C. Circuit Court vacate the Section 126 Rule or suspend its May 2003 compliance date. In August 2001 the D.C. Circuit Court issued an order tolling the compliance schedule until Federal EPA responded to the Court's remand. On April 30, 2002, Federal EPA announced that May 31, 2004 is the compliance date for the Section 126 Rule. Federal EPA published a notice in the Federal Register in May 2002 advising that no changes in the growth factors used to set the NOx budgets were warranted. In June 2002 AEP subsidiaries joined other utilities and industrial organizations in seeking a review of Federal EPA's action in the D.C. Circuit Court. This action is pending.

In 2000 the Texas Commission on Environmental Quality (formerly the Texas Natural Resource Conservation Commission) adopted rules requiring significant reductions in NOx emissions from utility sources, including SWEPCo and TCC. The compliance date is May 2003 for TCC and May 2005 for SWEPCo.

AEP is installing a variety of emission control technologies to reduce NOx emissions to comply with the applicable state and Federal NOx requirements. This includes selective catalytic reduction (SCR) technology on certain units and non-SCR technologies on a larger number of units. During 2001 SCR technology commenced operations on OPCo's Gavin Plant. Installation of SCR technology on Amos and Mountaineer plants was completed and commenced operation in May 2002. Construction of SCR technology at certain other AEP generating units continues. Non-SCR technologies have been installed and commenced operation on a number of units across the AEP System and additional units will be equipped with these technologies.

The AEP NOx compliance plan is a dynamic plan that is continually reviewed and revised as new information becomes available on the performance of installed technologies and the cost of planned technologies. Certain compliance steps may or may not be necessary as a result of this new information. Consequently, the plan has a range of possible outcomes. Our current estimates indicate that compliance with the NOx Rule, the Texas Commission on Environmental Quality rule and the Section 126 Rule could result in required capital expenditures in the range of $1.3 billion to $2 billion of which $843 million has been spent through December 31, 2002. The range of cost estimates reflects the uncertainty over the need for certain SCR projects.

Since compliance costs cannot be estimated with certainty, the actual cost to comply could be significantly different than the 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 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 did not properly find 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 required the SEC to revisit and identify factors supporting 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 support and explain its conclusions that the 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 – On October 15, 2002, certain subsidiaries of AEP filed claims against Enron and its subsidiaries in the bankruptcy proceeding filed by the Enron entities which are pending in the U.S. Bankruptcy Court for the Southern District of New York. 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 Company (HPL) from Enron. Various HPL related contingencies and indemnities remained unsettled at the date of Enron's bankruptcy. The timing of the resolution of the claims by the Bankruptcy Court is not certain.

In connection with the 2001 acquisition of HPL, we acquired exclusive rights to use and operate the underground Bammel gas storage facility pursuant to an agreement with BAM Lease Company, a now-bankrupt subsidiary of Enron. This exclusive right to use the referenced facility is for a term of 30 years, with a renewal right for another 20 years and includes the use of the Bammel storage reservoir and the related compression, treating and delivery systems. We have engaged in preliminary discussions with Enron concerning the possible purchase of the residual interest held by Enron in the Bammel storage facility and the possible resolution of outstanding issues between AEP and Enron relating to our acquisition of its interest in the Bammel storage facility. We are unable to predict whether these discussions will lead to an agreement on these subjects. If these discussions do not lead to an agreement, there may be a dispute with Enron concerning our ability to continue utilization of the Bammel storage facility under the existing agreement.

We also entered into an agreement with BAM Lease Company which grants HPL the right to use approximately 65 billion cubic feet of cushion gas (or pad gas) required for the normal operation of the Bammel gas storage facility. The Bammel Gas Trust, which purportedly owned approximately 55 billion cubic feet of the gas, had entered into a financing arrangement in 1997 with Enron and a group of banks. These banks purported to have certain rights to the gas in certain events of default. In connection with AEP's acquisition of HPL, the banks entered into an agreement granting HPL's use of the cushion gas and released HPL from liabilities and obligations under the financing arrangement. HPL was thereafter informed by the banks of a purported default by Enron under the terms of the referenced financing arrangement. In July 2002 the banks filed a lawsuit against HPL seeking a declaratory judgment that they have a valid and enforceable security interest in this cushion gas which would permit them to cause the withdrawal of this gas from the storage facility. In September 2002 HPL filed a general denial and certain counterclaims against the banks. Management is unable to predict the outcome of this lawsuit or its impact on results of operations and cash flows.

In 2001 AEP expensed $47 million ($31 million net of tax) for our estimated loss from the Enron bankruptcy. In 2002 AEP expensed an additional $6 million for a cumulative loss of $53 million ($34 million net of tax). The amounts expensed were based on an analysis of contracts where AEP and Enron entities are counterparties, the offsetting of receivables and payables, the application of deposits from Enron entities and management's analysis of the HPL related purchase contingencies and indemnifications.

Enron has recently instituted proceedings against other energy trading counter-parties challenging the practice of utilizing offsetting receivables and payables and related collateral across various Enron entities. We believe that we have the right to utilize similar procedures in dealing with payables, receivables and collateral with Enron entities by offsetting approximately $110 million of trading payables owed to various Enron entities against trading receivables due to us. We believe we have legal defenses to any challenge that may be made to the utilization of such offsets but at this time are unable to predict the ultimate resolution of this issue.

Shareholder Lawsuits – In the fourth quarter of 2002 lawsuits alleging securities law violations and seeking class action certification were filed in federal District Court, Columbus, Ohio against AEP, certain AEP executives, and in some of the lawsuits, members of the AEP Board of Directors and certain investment banking firms. The lawsuits claim that AEP failed to disclose that alleged "round trip" trades resulted in an overstatement of revenues, that AEP failed to disclose that AEP traders falsely reported energy prices to trade publications that published gas price indices and that AEP failed to disclose that it did not have in place sufficient management controls to prevent round trip trades or false reporting of energy prices. The plaintiffs seek recovery of an unstated amount of compensatory damages, attorney fees and costs. The cases are presently pending a decision by the Court on competing motions by certain plaintiffs and groups of plaintiffs' for designation as lead plaintiff. Once the Court selects a lead plaintiff, that lead plaintiff will file an amended complaint. AEP intends to vigorously defend against these actions. Also in the fourth quarter of 2002, two shareholder derivative actions were filed in state court in Columbus, Ohio against AEP and its Board of Directors alleging a breach of fiduciary duty for failure to establish and maintain adequate internal controls over AEP's gas trading operations; and, a lawsuit was filed against AEP, certain AEP executives and AEP's ERISA Plan Administrator in federal District Court for the Southern District of New York (subsequently transferred to federal District Court in Columbus, Ohio) alleging violations of the Employee Retirement Income Security Act in the selection of AEP stock as a investment alternative and in the allocation of assets to AEP stock. These cases are in the initial pleading stage. AEP intends to vigorously defend against these actions.

California Lawsuit – In November 2002 Cruz Bustamante, Lieutenant Governor of California, filed a lawsuit in Los Angeles County, California Superior Court against forty energy companies including AEP and two publishing companies alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. This case is in the initial pleading stage. AEP intends to vigorously defend against this action.

Arbitration of Williams Claim – In October 2002 AEP filed its demand for arbitration with the American Arbitration Association to initiate formal arbitration proceedings in a dispute with the Williams Companies (Williams). The proceeding results from Williams' repudiation of its obligations to provide physical power deliveries to AEP and Williams' failure to provide the monetary security required for natural gas deliveries by AEP. Consequently, both parties claimed default and terminated all outstanding natural gas and electric power trading deals among the various Williams and AEP affiliates. Williams claimed that AEP owes approximately $130 million in connection with the termination and liquidation of all trading deals. AEP believes it has valid claims arising from Williams' actions and is seeking, in part, a determination that either no amount is due or that a lesser amount is due from AEP to Williams (which is fully reserved by AEP) and the extent of any other damages and legal or equitable relief available. Although management is unable to predict the outcome of this matter, it is not expected to have a material impact on results of operations, cash flows or financial condition.

Energy Market Investigations – In February 2002 the FERC issued an order directing its Staff to conduct a fact-finding investigation into whether any entity, including Enron, manipulated short-term prices in electric energy or natural gas markets in the West or otherwise exercised undue influence over wholesale prices in the West, for the period January 1, 2000, forward. In April 2002 AEP furnished certain information to the FERC in response to their related data request.

Pursuant to the FERC's February order, on May 8, 2002, the FERC issued further data requests, including requests for admissions, with respect to certain trading strategies engaged in by Enron and, allegedly, traders of other companies active in the wholesale electricity and ancillary services markets in the West, particularly California, during the years 2000 and 2001. This data request was issued to AEP as part of a group of over 100 entities designated by the FERC as all sellers of wholesale electricity and/or ancillary services to the California Independent System Operator and/or the California Power Exchange.

The May 8, 2002 FERC data request required senior management to conduct an investigation into our trading activities during 2000 and 2001 and to provide an affidavit as to whether we engaged in certain trading practices that the FERC characterized in the data request as being potentially manipulative. Senior management complied with the order and denied our involvement with those trading practices.

On May 21, 2002, the FERC issued a further data request with respect to this matter to us and over 100 other market participants requesting information for the years 2000 and 2001 concerning "wash," "round trip" or "sale/buy back" trading in the Western System Coordinating Council (WSCC), which involves the sale of an electricity product to another company together with a simultaneous purchase of the same product at the same price (collectively, "wash sales"). Similarly, on May 22, 2002, the FERC issued an additional data request with respect to this matter to us and other market participants requesting similar information for the same period with respect to the sale of natural gas products in the WSCC and Texas. After reviewing our records, we responded to the FERC that we did not participate in any "wash sale" transactions involving power or gas in the relevant market. We further informed the FERC that certain of our traders did engage in trades on the Intercontinental Exchange, an electronic electricity trading platform owned by a group of electricity trading companies, including us, on September 21, 2001, the day on which all brokerage commissions for trades on that exchange were donated to charities for the victims of the September 11, 2001 terrorist attacks, which do not meet the FERC criteria for a "wash sale" but do have certain characteristics in common with such sales. In response to a request from the California attorney general for a copy of AEP's responses to the FERC inquires, we provided the pertinent information.

The PUCT also issued similar data requests to AEP and other power marketers. AEP responded to such data requests by the July 2, 2002 response date. The U.S. Commodity Futures Trading Commission (CFTC) issued a subpoena to us on June 17, 2002 requesting information with respect to "wash sale" trading practices. We responded to CFTC. In addition, the U.S. Department of Justice made a civil investigation demand to us and other electric generating companies concerning their investigation of the Intercontinental Exchange. We have completed a review of our trading activities in the United States for the last three years involving sequential trades with the same terms and counterparties. The revenue from such trading is not material to our financial statements. We believe that substantially all these transactions involve economic substance and risk transference and do not constitute "wash sales".

In August 2002 we received an informal data request from the SEC asking us to voluntarily provide documents related to "round trip" or "wash" trades. We have provided the requested information to the SEC.

In September 2002 we received a subpoena from FERC requesting information about our natural gas transactions and their potential impact on gas commodity prices in the New York City area. We responded to the subpoena in October 2002.

In October 2002 AEP dismissed several employees involved in natural gas marketing and trading after the Company determined that they provided inaccurate price information for use in indexes compiled and published by trade publications. AEP, subsequently, instituted measures that require all price information for use in market indexes be verified and reported through AEP's Chief Risk Officer's organization. We have and will continue to provide to the FERC, the SEC and the CFTC information relating to price data given to energy industry publications.

FERC Proposed Standard Market Design – In July 2002, the FERC issued its Standard Market Design (SMD) notice of proposed rulemaking, one of the most sweeping rulemaking proposals in its history. The proposed SMD rule seeks to standardize the structure and operation of wholesale electricity markets across the country. Key elements of FERC's proposal include standard rules and processes for all users of the electricity transmission grid, new transmission rules and policies, and the creation of certain markets to be operated by independent administrators of the grid in all regions. The FERC recently indicated that it would issue a white paper on the proposal in April 2003, in response to the numerous comments by FERC received on its proposal. The FERC is expected to issue its final rule in mid to late 2003. Because the rule is not yet finalized, management cannot predict the effect of the final rule on cash flows and results of operations.

FERC Proposed Security Standards – The FERC published for comment its proposed security standards as part of the SMD. These standards are intended to ensure all market participants have a basic security program that effectively protects the electric grid and related market activities. They require compliance by January 1, 2004. The impact of these proposed standards is far-reaching and includes significant penalties for non-compliance. These standards apply to market operations and transmission owners. For the AEP System this includes: power generation plants, transmission systems, distribution systems and related areas of business. FERC is considering new proposals to modify the scope and timetable for compliance with the standards. Unless FERC changes the scope and timing of the original proposed standards, those standards could result in significant expenditures and operational changes in a compressed time frame, and may adversely affect our results of operations and cash flows if such costs are not recovered from customers.

FERC Market Power Mitigation – A FERC order issued in November 2001 on AEP's triennial market based wholesale power rate authorization update required certain mitigation actions that AEP would need to take for sales/purchases within its control area and required AEP to post information on its website regarding its power system's status. As a result of a request for rehearing filed by AEP and other market participants, FERC issued an order delaying the effective date of the mitigation plan until after a planned technical conference on market power determination. No such conference has been held and management is unable to predict the timing of any further action by the FERC or its affect on future results of operations and cash flows.

Other – We are 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 results of operations, cash flows or financial condition.

10. Guarantees

In November 2002 the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45) which clarifies the accounting to recognize a liability related to issuing a guarantee, as well as additional disclosures of guarantees. This new guidance is an interpretation of SFAS 5, 57, and 107 and a rescission of FIN 34. The initial recognition and initial measurement provisions of FIN 45 is effective on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements of FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002.

There are no liabilities recorded for all of the guarantees described below in accordance with FIN 45 as these guarantees were entered into prior to December 31, 2002. There is no collateral held in relation to these guarantees and there is no recourse to third parties in the event these guarantees are drawn.

Certain AEP subsidiaries have entered into standby letters of credit (LOC) with third parties. These LOCs cover gas and electricity trading contracts, construction contracts, insurance programs, security deposits, debt service reserves, drilling funds and credit enhancements for issued bonds. All of these LOCs were issued at a subsidiary level of AEP in the subsidiaries' ordinary course of business. TCC issued one of the LOCs for credit enhancement of issued bonds. The maximum future payments of all the LOCs are approximately $166 million with maturities ranging from January 2003 to December 2007. Since AEP is the parent to all these subsidiaries, it holds all assets of the subsidiary as collateral. There is no recourse to third parties in the event these letters of credit are drawn.

The following AEP subsidiaries have entered into guarantees of third party obligations:

CSW Energy and CSW International have guaranteed 50% of the required debt service reserve of Sweeny Cogeneration, an IPP of which

CSW Energy is a 50% owner. The guarantee was provided in lieu of Sweeny funding the debt reserve as a part of financing. In the event that Sweeny does not make the required debt payments, CSW Energy and CSW International have a maximum future payment exposure of approximately $3.7 million, which expires June 2020.

Additionally, CSW guaranteed 50% of the required debt service reserve for Polk Power Partners, another IPP of which CSW Energy owns 50%. In the event that Polk Power does not make the required debt payments, CSW has a maximum future payment exposure of approximately $4.7 million, which expires July 2010.

In connection with reducing the cost of the lignite mining contract for its Henry W. Pirkey Power Plant, SWEPCo has agreed under certain conditions, to assume the revolving credit agreement, capital lease obligations, and term loan payments of the mining contractor. In the event the mining contractor defaults under any of these agreements, SWEPCo's total future maximum payment exposure is approximately $74 million with maturity dates ranging from April 2003 to February 2012.

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 approximately $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, 2002 the cost to reclaim the mine is estimated to be approximately $36 million. This guarantee ends upon depletion of reserves estimated at 2035 plus 6 years to complete reclamation.

In connection with the ability for Mutual Energy CPL L.P. (former subsidiary of AEP sold to Centrica on December 23, 2002) to compete in the CPL territory and to secure transition charges, AEP provided a guarantee that AEP would pay transition charges if Mutual Energy CPL failed to meet certain obligations. At the time of sale this guarantee (matures in February 2003) was not revoked. The future maximum payment exposure is $12.2 million. In February 2003, the guarantee matured and no payments under the guarantee were required.

In connection with the ERCOT transmission congestion auction, AEP has guaranteed the obligations of Mutual Energy CPL L.P. (former subsidiary of AEP sold to Centrica on December 23, 2002) and Mutual Energy WTU L.P. (former subsidiary of AEP sold to Centrica on December 23, 2002). At the time of sale these guarantees were not revoked. The total future maximum payment exposure for both companies is approximately $0.6 million. In January 2003 these guarantees matured and no payments under the guarantees were required.

See Note 26 "Minority Interest in Finance Subsidiary" for disclosure of the guaranteed support of AEP for Caddis Partners, LLC.

AEP and all its registrant and non-registrant subsidiaries enter into several types of contracts, which would require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. At this time AEP cannot estimate the maximum potential payment for any of these indemnifications due to the uncertainty of future events. In addition, as of December 31, 2002, there are no liabilities required for any indemnifications.

AEP and its regulated and non-regulated subsidiaries lease certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, we have committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. At December 31, 2002, the maximum potential loss for these lease agreements was approximately

$50 million assuming the fair market value of the equipment is zero at the end of the lease term.

11. Sustained Earnings Improvement Initiative:

In response to difficult conditions in AEP's business, a Sustained Earnings Improvement (SEI) initiative was undertaken company-wide in the fourth quarter of 2002, as a cost-saving and revenue-building effort to build long-term earnings growth.

Termination benefits expense relating to 1,120 terminated employees totaling $75.4 million pre-tax was recorded in the fourth quarter of 2002. Of this amount, AEP paid $9.5 million to 312 terminated employees and recorded a provision for $65.9 million related to 808 terminated employees. The payments and accruals were classified as Maintenance and Other Operation expense on the Consolidated Statements of Operations. We determined that the termination of the employees under our SEI initiative did not constitute a curtailment under the provisions of SFAS No. 88 "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits".

In addition, certain buildings and corporate aircraft are being sold in an effort to reduce ongoing operating expenses.

12. Acquisitions, Dispositions and Discontinued Operations:

Acquisitions

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

2002

Acquisition of Nordic Trading

In January 2002 AEP acquired for $2.2 million and other assumed liabilities the trading operations, including key staff, of Enron's Norway and Sweden-based energy trading businesses (Nordic Trading). Results of operations are included in AEP's Consolidated Statements of Operations from the date of acquisition. The excess of cost over fair value of the net assets acquired was approximately $4.0 million which was recorded as Goodwill. Subsequently in the fourth quarter of 2002, a decision was made to exit the non-core trading business in Europe and to close or sell Nordic Trading as discussed under the "Discontinued Operations" section of this note.

Acquisition of USTI

In January 2002 AEP acquired 100% of the stock of United Sciences Testing, Inc. (USTI) for $12.5 million. USTI provides equipment and services related to automated emission monitoring of combustion gases to both AEP affiliates and external customers. Results of operations are included in AEP's Consolidated Statements of Operations from the date of acquisition.

2001

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 determined by independent appraisal or by Company's management based on information currently available and on current assumptions as to future operations. Based on a final purchase price allocation the excess of cost over fair value of the net assets acquired was approximately $153 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.

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:

- SWEPCo, an AEP subsidiary, purchased the Dolet Hills mining operations and assumed the existing mine reclamation liabilities at its jointly owned lignite reserves in Louisiana.

- Quaker Coal Company as part of a bankruptcy proceeding settlement. AEP also 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 continues to operate the mines and facilities which employ over 800 individuals. See Note 13b "Asset Impairments and Investment Value Losses".
- MEMCO Barge Line added 1,200 hopper barges and 30 towboats to AEP's existing barging fleet. MEMCO's 450 employees operate the barge line. MEMCO added major barging operations on the Mississippi and Ohio rivers to AEP's barging operations on the Ohio and Kanawha rivers.
- U.K. Generation added 4,000 megawatts of coal-fired generation from 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. See Note 13b "Asset Impairments and Investment Value Losses".
- A 20% equity interest in Caiua, a Brazilian electric operating company which is a subsidiary of Vale. See Note 21, "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. See Note 13b "Asset Impairments and Investment Value Losses".
- Indian Mesa Wind Project consisting of 160 megawatts of wind generation located near Fort Stockton, Texas.
- Acquired existing contracts and hired key staff from Enron's London-based international coal trading group.

Regarding the 2002 and 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.

<u>Dispositions</u>

2002

In 2002, AEP completed a number of disposals of assets determined to be non-core:

Disposal of SEEBOARD

On June 18, 2002, AEP, through a wholly owned subsidiary, entered into an agreement, subject to European Union (EU) approval, to sell its consolidated subsidiary SEEBOARD, a U.K. electricity supply and distribution company. EU approval was received July 25, 2002 and the sale was completed on July 29, 2002. AEP received approximately $941 million in net cash from the sale, subject to a working capital true up, and the buyer assumed SEEBOARD debt of approximately $1.12 billion, resulting in a net loss of $345 million at June 30, 2002. In accordance with SFAS 144 the results of operations of SEEBOARD have been classified as Discontinued Operations for all years presented. A net loss of $22 million was classified as Discontinued Operations in the second quarter of 2002. The remaining $323 million of the net loss has been classified as a transitional impairment loss from the adoption of SFAS 142 (see Notes 2 and 3) and has been reported as a Cumulative Effect of Accounting Change retroactive to January 1, 2002. A $59 million reduction of the net loss was recognized in the second half of 2002 to reflect changes in exchange rates to closing, settlement of working capital true-up and selling expenses. The net total loss recognized on the disposal of SEEBOARD was $286 million. Proceeds from the sale of SEEBOARD were used to pay down bank facilities and short-term debt.

The assets and liabilities of SEEBOARD were aggregated on AEP's Consolidated Balance Sheets as Assets of Discontinued Operations and Liabilities of Discontinued Operations as of December 31, 2001. The major classes of SEEBOARD's assets and liabilities of discontinued operations were:

	December 31, 2001 (in millions)
Assets:	
Current Assets	$ 324
Plant,Property and Equipment, Net	1,283
Goodwill	1,129
Other Assets	96
Total Assets of Discontinued Operations	$2,832
Liabilities:	
Current Liabilities	$ 752
Long-term Debt	701
Deferred Income Taxes	268
Other Liabilities	77
Total Liabilities of Discontinued Operations	$1,798

Disposal of CitiPower

On July 19, 2002, AEP, through a wholly owned subsidiary entered into an agreement to sell Citipower, a retail electricity and gas supply and distribution subsidiary in Australia. AEP completed the sale on August 30, 2002 and received net cash of approximately $175 million and the buyer assumed CitiPower debt of approximately $674 million. AEP recorded a net charge totaling $125 million as of June 30, 2002. The charge included an impairment loss of $98 million on the remaining carrying value of an intangible asset related to a distribution license for CitiPower. The remaining $27 million of net loss was classified as a transitional goodwill impairment loss from the adoption of SFAS 142 (see Notes 2 and 3) and was recorded as a cumulative effect of a change in accounting principle retroactive to January 1, 2002.

The loss on the sale of CitiPower increased $24 million to $149 million in the second half of 2002 based on actual closing amounts and exchange rates.

CitiPower's results of operations have been reclassified as Discontinued Operations in accordance with SFAS 144. The assets and liabilities of Citipower have been aggregated on the December 31, 2001, balance sheet as Assets of Discontinued Operations and Liabilities of Discontinued Operations. The major classes of CitiPower's assets and liabilities of discontinued operations are:

	December 31, 2001 (in millions)
Assets:	
Current Assets	$ 138
Plant, Property and Equipment, Net	495
Goodwill/Intangibles	466
Other Assets	23
Total Assets of Discontinued Operations	$1,122
Liabilities:	
Current Liabilities	$ 83
Long-term Debt	612
Deferred Income Taxes	55
Other Liabilities	34
Total Liabilities of Discontinued Operations	$784

Total revenues and pretax profit (loss) of the discontinued operations of SEEBOARD and CitiPower were:

	SEEBOARD (in millions)
Revenues:	
12 months ended 12/31/02	$ 694
12 months ended 12/31/01	1,451
12 month ended 12/31/00	1,596
Pretax Profit:	
12 months ended 12/31/02	$ 180
12 months ended 12/31/01	104
12 months ended 12/31/00	91

	CitiPower (in millions)
Revenues:	
12 months ended 12/31/02	$ 204
12 months ended 12/31/01	350
12 months ended 12/31/00	338
Pretax Profit:	
12 months ended 12/31/02	$ (190)
12 months ended 12/31/01	(4)
12 months ended 12/31/00	20

Disposition of Texas REPs

In April 2002 AEP reached a definitive agreement, subject to regulatory approval, to sell two of its Texas retail electric providers (REPs) to Centrica, a provider of retail energy and other consumer services. PUCT regulatory approval for the sale was obtained in December 2002. On December 23, 2002 AEP sold to Centrica, the general partner interests and the limited partner interests in Mutual Energy CPL L.P. and Mutual Energy WTU L.P. for a base purchase price paid in cash at closing and certain additional payments, including a net working capital payment. Centrica paid a base purchase price of $145.5 million which was based on a fair market value per customer established by an independent appraiser and an agreed customer count. AEP recorded a net gain totaling $83.7 million in Other Income. AEP will provide Centrica with a power supply contract for the two REPs and back-office services related to these customers for a two-year period. In addition, AEP retained the right to share in earnings from the two REPs above a threshold amount through 2006 in the event the Texas retail market develops increased earnings opportunities. Under the Texas Legislation, REPs are subject to a clawback liability if customer change does not attain thresholds required by the legislation. AEP is responsible for a portion of such liability, if any, for the period it operated the REPs in the Texas competitive retail market (January 1, 2002 through December 23, 2002). In addition, AEP retained responsibility for regulatory obligations arising out of operations before closing. AEP's wholly-owned subsidiary Mutual Energy Service Company LLC (MESC) received an up-front payment of approximately $30 million from Centrica associated with the back-office service agreement, and MESC deferred its right to receive payment of an additional amount of approximately $9 million to secure certain contingent obligations. These prepaid service revenues were deferred on the books of MESC to be amortized over the two-year term of the back office service agreement.

2001

In March 2001 CSWE, a subsidiary company, 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 OPCo, an AEP subsidiary, 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, resulting in an after tax gain of approximately $7 million. During 2002, due to decreasing market value of the shares, we have reduced the value of them to zero.

2000

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 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 writedown is included in Other Income on AEP's Consolidated Statements of Operations. 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, a subsidiary company 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 Accumulated 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).

Discontinued Operations

The operations shown below were discontinued or classified as held for sale in 2002. Results of operations of these businesses have been reclassified as shown in the following table.

(in millions)	SEE-BOARD	CitiPower	Pushan	Eastex	Total
2002 Revenue	$ 694	$204	$57	$ 73	$1,028
2001 Revenue	1,451	350	57	-	1,858
2000 Revenue	1,596	338	57	-	1,991
2002 Earnings (Loss) After Tax	96	(123)	(7)	(156)	(190)
2001 Earnings (Loss) After Tax	88	(6)	4	-	86
2000 Earnings (Loss) After Tax	99	17	7	(1)	122

13. Asset Impairments and Investment Value Losses:

In 2002 AEP recorded pre-tax impairments of assets (including goodwill) and investments totaling $1.426 billion (consisting of approximately $866.6 million related to asset impairments, $321.1 million related to Investment Value and Other Impairment Losses, and $238.7 million related to Discontinued Operations) that reflected downturns in energy trading markets, projected long-term decreases in electricity prices, and other factors. These impairments exclude the transitional impairment loss from adoption of SFAS142 (see Notes 2 and 3). The categories of impairments included:

	2002 Pre-Tax Estimated Loss (in millions)
Asset Impairments Held for Sale	$ 483.1
Asset Impairments Held and Used	651.4
Investment Value Losses	291.9
Total	$1,426.4

a. Assets Held for Sale

In 2002, AEP recorded the following estimated loss on disposal of assets (including Goodwill) held for sale:

Assets Held for Sale	2002 Pre-Tax Estimated Loss on Disposal (in millions)	Business
Eastex	$218.7	Wholesale
Pushan Power	20.0	Other
Total Impairment Losses Included in Discontinued Operations	$238.7	
Telecommunication – AEPC/C3	$158.5	Other
Newgulf Facility	11.8	Wholesale
Nordic Trading	5.3	Wholesale
Excess Equipment	23.9	Wholesale
Excess Real Estate	15.7	Wholesale
Total Included in Asset Impairment Losses	$215.2	
Telecommunications – AFN	$ 13.8	Other
Water Heater Program	3.2	Wholesale
Gas Power Systems	12.2	Wholesale
Total Included in Investment Value and Other Impairment Losses	$ 29.2	
Total-All Held for Sale Losses	$483.1	

Eastex

In 1998, CSW began construction of a natural gas-fired cogeneration facility (Eastex) located near Longview, Texas and commercial operations commenced in December 2001. In June 2002, AEP requested that the FERC allow it to modify the FERC Merger Order and substitute Eastex as a required divestiture under the order, due to the fact that the agreed upon market-power related divestiture of a plant in Oklahoma was no longer feasible. The FERC approved the request at the end of September 2002. Subsequently, in the fourth quarter of 2002 AEP solicited bids for the sale of Eastex and several interested buyers were identified by December 2002. A sale of assets is expected to be completed by the end of 2003 with an estimated pre-tax loss on sale of $218.7 million included in Discontinued Operations in the Consolidated Statements of Operations. The estimated loss was based on the estimated fair value of the facility and indicative bids by interested buyers.

Results of operations of Eastex have been reclassified as Discontinued Operations in accordance with SFAS 144 as shown in Note 12. The assets and liabilities of Eastex have been included on AEP's Consolidated Balance Sheets as held for sale. The major classes of assets and liabilities held for sale are:

	2002	2001
	(in millions)	
Assets:		
Current Assets	$15	$ -
Property, Plant and Equipment, Net	-	217
Other Assets	-	3
Total Assets Held for Sale	$15	$220
Liabilities:		
Current Liabilities	$ 8	$ 5
Other Liabilities	4	1
Total Liabilities Held for Sale	$12	$ 6

Pushan Power Plant

In the fourth quarter of 2002, AEP began active negotiations to sell its interest in the Pushan Power Plant (Pushan) in Nanyang, China to the minority interest partner. Negotiations are expected to be completed by the second quarter of 2003 with an estimated pre-tax loss on disposal of $20.0 million, based on an indicative price expression. The estimated pre-tax loss on disposal is classified in Discontinued Operations in the Consolidated Statements of Operations.

Results of operations of Pushan have been reclassified as Discontinued Operations in accordance with SFAS 144 as discussed in Note 12. The assets and liabilities of Pushan have been classified on AEP's Consolidated Balance Sheets as held for sale. The major classes of assets and liabilities held for sale are:

	2002	2001
	(in millions)	
Assets:		
Current Assets	$ 19	$ 17
Property, Plant and Equipment, Net	132	161
Total Assets Held for Sale	$151	$178
Liabilities:		
Current Liabilities	$ 28	$ 27
Long-term Debt	25	30
Other Liabilities	26	24
Total Liabilities Held for Sale	$ 79	$ 81

Telecommunications

AEP had developed businesses to provide telecommunication services to businesses and to other telecommunication companies through broadband fiber optic networks operated in conjunction with AEP's electric transmission and distribution lines. The businesses included AEP Communications, LLC (AEPC), C3 Communications, Inc. (C3), and a 50% share of AFN Networks, LLC (AFN), a joint venture. Due to the difficult economic conditions in these businesses and the overall telecommunications industry, and other operating problems, the AEP Board approved in December 2002 a plan to cease operations of these businesses. AEP took steps to market the assets of the businesses to potential interested buyers in the fourth quarter of 2002. A number of potential buyers have made offers for the assets of C3. Potential buyers have indicated interest in the assets of AFN. A formal offering of the assets of AEPC will begin early in 2003. The complete sale of all telecommunication assets is expected to be completed by the end of 2003 with an estimated pre-tax impairment loss of $158.5 million (related to AEPC and C3) classified in Asset Impairments in the Consolidated Statements of Operations and an estimated pre-tax loss in value of the investment in AFN of $13.8 million classified in Investment Value and Other Impairment Losses in the Consolidated Statement of Operations. The estimated losses are based on indicative bids by potential buyers.

$6 million and $182 million of Property, Plant and Equipment, net of accumulated depreciation of the telecommunication businesses have been classified on AEP's Consolidated Balance Sheets as held for sale in 2002 and 2001, respectively.

Newgulf Facility
In 1995, CSW purchased an 85 MW gas-fired peaking electrical generation facility located near Newgulf, Texas (Newgulf). In October 2002 AEP began negotiations with a likely buyer of the facility. A sale is now expected to be completed by the end of 2003 with an estimated pre-tax loss on sale of $11.8 million based on an indicative bid by the likely buyer. The estimated loss on disposal is classified in Asset Impairments on the Consolidated Statements of Operations. Newgulf's Property, Plant and Equipment, net of accumulated depreciation, of $6 million in 2002 and $17 million in 2001 has been classified on AEP's Consolidated Balance Sheets as held for sale.

Nordic Trading
In October 2002 AEP announced that its ongoing energy trading operations would be centered around its generation assets. As a result, AEP took steps to exit its coal, gas, and electricity trading activities in Europe, except for those activities necessary to support the U.K. Generation operations. The Nordic Trading business acquired earlier in 2002 (see Note 12) was made available for sale to potential buyers. The estimated pre-tax loss on disposal in 2002 of $5.3 million, consisted of impairment of goodwill of $4.0 million (see Note 3) and impairment of assets of $1.3 million. The estimated loss of $5.3 million is included in Asset Impairments on the Consolidated Statements of Operations. Management's determination of a zero fair value was based on discussions with a potential buyer. There are no assets and liabilities of Nordic Trading to be classified on AEP's Consolidated Balance Sheets as held for sale.

Excess Equipment
In November 2002, as a result of a cancelled development project, AEP obtained title to a surplus gas turbine generator. AEP has been unsuccessful in finding potential buyers of the unit, including its own internal generation operators, due to an over-supply of generation equipment available for sale. Sale of the turbine is now projected before the end of 2003 with an estimated 2002 pre-tax loss on disposal of $23.9 million, based on market prices of similar equipment. The loss is included in Asset Impairments on the Consolidated Statements of Operations. The Other asset of $12 million in 2002 and $31 million in 2001 has been classified on AEP's Consolidated Balance Sheets as held for sale.

Excess Real Estate
In the fourth quarter of 2002, AEP began to market an under-utilized office building in Dallas, TX obtained through the merger with CSW. One prospective buyer has executed an option to purchase the building. Sale of the facility is projected by second quarter 2003 and an estimated 2002 pre-tax loss on disposal of $15.7 million has been recorded, based on the option sale price. The estimated loss is included in Asset Impairments on the Consolidated Statements of Operations. The Property asset of $18 million in 2002 and $36 million in 2001 has been classified on AEP's Consolidated Balance Sheets as held for sale.

Water Heater Program
AEP operated a program to lease electric water heaters to residential and commercial customers until a decision was reached in the fourth quarter of 2002 to discontinue the program and to offer the assets for sale. Negotiations are underway with a qualified buyer, and sale of the assets is projected by the end of the first quarter of 2003. The estimated 2002 pre-tax loss on disposal of $3.2 million was based on the expected contract sales price. The loss is included in Investment Value and Other Impairment Losses on the Consolidated Statements of Operations. The assets and liabilities have been classified on AEP's Consolidated Balance Sheets as held for sale. The major classes of assets held for sale are:

	2002	2001
	(in millions)	
Assets:		
Current Assets	$ 1	$ 2
Property, Plant and Equipment, Net	38	48
Total Assets Held for Sale	$39	$50

Gas Power Systems
AEP acquired in 2001 a 75% interest in a startup company seeking to develop low-cost peaking generator sets powered by surplus jet turbine engines. The first quarter of 2002, AEP recognized a goodwill impairment loss of $12.2 million due to technological and operating problems (See Note 3). The loss was recorded in Investment Value and Other Impairment Losses on the Consolidated Statements of Operations. The fair values of the remaining assets and liabilities were excluded from AEP's Consolidated Balance Sheets as held for sale, as the impact was insignificant. AEP's remaining interest was sold in January 2003.

b. Assets Held and Used

In 2002, AEP recorded the following impairments related to assets (including Goodwill) held and used to Asset Impairments on the Consolidated Statements of Operations:

Assets Held and Used	2002 Pre-Tax Loss	Business Segment
	(in millions)	
U.K. Generation	$548.7	Wholesale
AEP Coal	59.9	Wholesale
Texas Plants	38.1	Wholesale
Ft. Davis Wind Farm	4.7	Wholesale
Total – ALL Held and Used Losses	$ 651.4	

U.K. Generation Plants
In December 2001, AEP acquired two coal-fired generation plants (U.K. Generation) in the U.K. for a cash payment of $942.3 million and assumption of certain liabilities. Subsequently and continuing through 2002, wholesale U.K. electric power prices declined sharply as a result of domestic over-capacity and static demand. External industry forecasts and AEP's own projections made during the fourth quarter of 2002 indicate that this situation may extend many years into the future. As a result, the U.K. Generation fixed asset carrying value at year-end 2002 was substantially impaired. A December 2002 probability-weighted discounted cash flow analysis of the fair value of our U.K. Generation indicated a 2002 pre-tax impairment

loss of $548.7 million, including a goodwill impairment of $166.1 million as discussed in Note 3. The cash flow analysis used a discount rate of 6% over the remaining life of the assets and reflected assumptions for future electricity prices and plant operating costs. This impairment loss is included in Asset Impairments on the Consolidated Statements of Operations.

AEP Coal

In October 2001, AEP acquired out of bankruptcy certain assets and assumed certain liabilities of nineteen coal mine companies formerly known as "Quaker Coal" and re-identified as "AEP Coal". During 2002 the coal operations suffered a decline in forward prices and adverse mining factors that culminated in the fourth quarter of 2002 and significantly reduced mine productivity and revenue. Based on an extensive review of economically accessible reserves and other factors, future mine productivity and production is expected to continue to be below historical levels. In December 2002, a probability-weighted discounted cash flow analysis of fair value of the mines was performed which indicated a 2002 pre-tax impairment loss of $59.9 million including a goodwill impairment of $3.6 million as discussed in Note 3. This impairment loss is included in Asset Impairments on the Consolidated Statements of Operations.

Texas Plants

In September 2002 AEP proposed closing 16 gas-fired power plants in the ERCOT control area of Texas (8 TNC plants and 8 TCC plants). ERCOT indicated that it may designate some of those plants as "reliability must run" (RMR) status. In October ERCOT designated seven RMR plants (3 TNC plants and 4 TCC plants) and approved AEP's plan to inactivate nine other plants (5 TNC plants and 4 TCC plants). The process of moving the plants to inactive status took approximately two months. Employees of the plants moved to inactive status (approximately 180) were eligible for severance and outplacement services.

As a result of the decision to inactivate TNC plants, a write-down of utility assets of approximately $34.2 million (pre-tax) was recorded in Asset Impairments expense during the third quarter 2002. The decision to inactivate the TCC plants resulted in a write-down of utility assets of approximately $95.6 million (pre-tax), which was deferred and recorded in Regulatory Assets during the third quarter 2002.

During the fourth quarter 2002, evaluations continued as to whether assets remaining at the inactivated plants, including materials, supplies and fuel oil inventories, could be utilized elsewhere within the AEP System. As a result of such evaluations, TNC recorded an additional asset impairment charge to Asset Impairments expense of $3.9 million (pre-tax) in the fourth quarter 2002. In addition TNC recorded related inventory write-downs of $2.6 million ($1.2 million in Fuel and Purchased Energy: Electricity and $1.4 million in Maintenance and Other Operation expense). Similarly, TCC recorded an additional asset impairment write-down of $6.7 million (pre-tax), which was deferred and recorded in Regulatory Assets in the fourth quarter 2002. TCC also recorded related inventory write-downs of $14.9 million which was deferred and recorded in Regulatory Assets in the fourth quarter 2002.

The total Texas plant asset impairment of $38.1 million in 2002 (all related to TNC) is included in Asset Impairments on the Consolidated Statement of Operations.

RMR plants are required to ensure the reliability of the power grid, even if electricity from those plants is not required to meet market needs. ERCOT and AEP negotiated interim contracts for the seven RMR plants through December 2003, however, ERCOT has the right to terminate the plants from RMR status upon 90 days written notice.

In December 2002, TCC filed a plan of divestiture with the PUCT proposing to sell all of its power generation assets, including the eight gas-fired generating plants that were either inactivated or designated as RMR status. See Texas Restructuring section of the "Customer Choice and Industry Restructuring" Note 8 for further discussion of the divestiture plan and anticipated timeline.

Ft. Davis Wind Farm
In the 1990's, CSW developed a 6 MW facility wind energy project located on a lease site near Ft. Davis, Texas. In the fourth quarter of 2002 AEP engineering staff determined that operation of the facility was no longer technically feasible and the lease of the underlying site should not be renewed. Dismantling of the facility will be complete by the end of 2003 with an estimated 2002 pre-tax loss on abandonment of $4.7 million. The loss was recorded in Asset Impairments on the Consolidated Statements of Operations. The facility will continue to be classified as held and used until disposal is complete.

c. Investment Values

In 2002, AEP recorded the following declines in fair value on investments accounted for under APB 18 that were considered to be other than temporarily impaired as shown in the table below:

Investment Value Impairment Loss Items	2002 Pre-Tax Estimated Loss (in millions)	Business Segment
Grupo Rede Investment – Brazil	$217.0	Other
South Coast Power	63.2	Other
Misc. Technology Investments	11.7	Other
Total	$291.9	

Grupo Rede Investment
In December 2002, AEP recorded an other than temporary impairment totaling $141.0 million ($217.0 million net of federal income tax benefit of $76.0 million) of its 44% equity investment in Vale and its 20% equity interest in Caiua, both Brazilian electric operating companies (referred to as Grupo Rede). This amount is included in Investment Value and Other Impairment Losses on the Consolidated Statements of Operations. As of September 30, 2002, AEP had not recognized its cumulative equity share of operating and foreign currency translation losses of approximately $88 million and $105 million, respectively, due to the existence of a put option that permits AEP to require Grupo Rede to purchase our equity at a minimum price equal to the U.S. dollar equivalent of the original purchase price. In January 2002 AEP evaluated through an independent credit assessment the ability of Grupo Rede to fulfill its responsibilities under the put option and concluded that the carrying value of the original investment was reasonable.

During 2002, there has been a continuing decline in the Brazilian power industry and the value of the local currency. Events in the fourth quarter of 2002 led us to change our view that Grupo Rede would be able to fulfill its responsibilities under the put option. These events included two downgrades of Caiua debt by Moody's, resulting in a rating of Caa1. Caiua is an intermediate holding company which owns substantially all of the utility companies in the Grupo Rede system. The downgrading of Caiua's credit ratings to a level well below investment grade casts significant doubt on the ability of Grupo Rede to honor the put option. Grupo Rede is in the process of restructuring some of its debts, and as a condition for participating in the restructuring, during November 2002 a creditor of Grupo Rede requested that AEP agree not to exercise the put option prior to March 31, 2007. AEP agreed and in exchange received an extension of the put option from the previous end date of 2009 through 2019. Based on the factors noted above, AEP could no longer reasonably believe that our investment could be recovered, resulting in the recording of the impairment.

South Coast Power Investment
South Coast Power is a 50% owned joint venture that was formed in 1996 to build and operate a merchant closed-cycle gas turbine generator at Shoreham, U.K.. South Coast Power is subject to the same adverse wholesale electric power rates described for U.K. Generation above. A December 2002 projected cash flow estimate of the fair value of the investment indicated a 2002 pre-tax other than temporary impairment of the equity interest (which included the fair value of supply contracts held by South Coast Power and accounted for in accordance with SFAS 133) in the amount of $63.2 million. This loss of investment value is included in Investment Value and Other Impairment Losses on the Consolidated Statements of Operations.

Technology Investments
AEP previously made investments totaling $11.7 million in four early-stage or startup technologies involving pollution control and procurement. An analysis in December 2002 of the viability of the underlying technologies and the projected performance of the investee companies indicated that the investments were unlikely to be recovered, and an other than temporary impairment of the entire amount of the equity interest under APB 18 was recorded. The loss of investment value is included in Investment Value and Other Impairment Losses on the Consolidated Statements of Operations.

14. Benefit Plans:

Pension and Other Postretirement Benefits

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 either one qualified plan or both a qualified and a nonqualified pension plan. Other postretirement benefit (OPEB) plans are sponsored by the AEP System to provide medical and death benefits for retired employees in the U.S.

AEP also has a foreign pension plan for employees of AEP Energy Services U.K. Generation Limited (Genco) in the U.K. Genco employees participate in their existing pension plan acquired as part of AEP's purchase of two generation plants in the U.K. in December 2001.

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, 2002, and a statement of the funded status as of December 31 for both years:

	U.S. Pension Plans		U.S. OPEB Plans		
	2002	2001	2002	2001	
	(in millions)				
Reconciliation of Benefit Obligation:					
Obligation at January 1	$3,292	$3,161	$ 1,645	$1,668	
Service Cost	72	69	34	30	
Interest Cost	241	232	114	114	
Participant Contributions	-	-	13	8	
Plan Amendments	(2)	-	-	7	(a)
Actuarial (Gain) Loss	258	121	152	192	
Divestitures	-	-	-	(287)	(b)
Benefit Payments	(278)	(291)	(81)	(88)	
Curtailments	-	-	-	1	
Obligation at December 31	$3,583	$3,292	$ 1,877	$1,645	
Reconciliation of Fair Value of Plan Assets:					
Fair Value of Plan Assets at January 1	$3,438	$3,911	$ 711	$ 704	
Actual Return on Plan Assets	(371)	(182)	(57)	(31)	
Company Contributions	6	-	137	118	
Participant Contributions	-	-	13	8	
Benefit Payments	(278)	(291)	(81)	(88)	
Fair Value of Plan Assets at December 31	$2,795	$3,438	$ 723	$ 711	

Funded Status:				
Funded Status at December 31	$ (788)	$ 146	$(1,154)	$ (934)
Unrecognized Net Transition (Asset) Obligation	(7)	(15)	233	263
Unrecognized Prior-Service Cost	(13)	(12)	6	7
Unrecognized Actuarial (Gain) Loss	1,020	35	896	649
Prepaid Benefit (Accrued Liability)	$ 212	$ 154	$ (19)	$ (15)

(a) Related to the purchase of Houston Pipe Line Company and MEMCO Barge Line.
(b) Related to the sale 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 2001 and 2002 were recorded in 2002.

	U.S. Pension Plans		U.S. OPEB Plans	
	2002	2001	2002	2001
	(in millions)			
Prepaid Benefit Costs	$ 255	$ 205	$ -	$ 1
Accrued Benefit Liability	(44)	(51)	(19)	(16)
Additional Minimum Liability	(944)	(15)	N/A	N/A
Intangible Asset	45	9	N/A	N/A
Accumulated Other Comprehensive Income	900	6	N/A	N/A
Net Asset (Liability)	$ 212	$ 154	$(19)	$ (15)
Other Comprehensive (Income) Expense Attributable to Change in Additional Pension Liability Recognition	$ 894	$(4)	N/A	N/A

N/A = Not Applicable

The value of our qualified plans' assets has decreased from $3.438 billion at December 31, 2001 to $2.795 billion at December 31, 2002. The qualified plans paid $272 million in benefits to plan participants during 2002 (nonqualified plans paid $6 million in benefits). The investment returns and declining discount rates have changed the status of our qualified plans from overfunded (plan assets in excess of projected benefit obligations) by $146 million at December 31, 2001 to an underfunded position (plan assets are less than projected benefit obligations) of $788 million at December 31, 2002. Due to the qualified plans currently being underfunded, the Company recorded a charge to Other Comprehensive Income (OCI) of $585 million, and a Deferred Income Tax Asset of $315 million, offset by a Minimum Pension Liability of $662 million and reduction to prepaid costs and intangible assets of $238 million. The charge to OCI does not affect earnings or cash flow. Also, because of the recent reductions in the funded status of our qualified plans, we expect to make cash contributions to our qualified plans of approximately $66 million in 2003 increasing to approximately $108 million per year by 2005.

The AEP System's qualified pension plans had accumulated benefit obligations in excess of plan assets of $661 million at December 31, 2002.

The AEP System's nonqualified pension plans had accumulated benefit obligations in excess of plan assets of $72 million at December 31, 2002 and $66 million at December 31, 2001. There are no assets in the nonqualified plans.

The AEP System's OPEB plans had accumulated benefit obligations in excess of plan assets of $1,154 million and $934 million at December 31, 2002 and 2001, respectively.

The Genco pension plan had $7 million and $10 million at December 31, 2002 and 2001, respectively, of accumulated benefit obligations in excess of plan assets.

The following table provides the components of AEP's net periodic benefit cost (credit) for the plans for fiscal years 2002, 2001 and 2000:

	U.S. Pension Plans			U.S. OPEB Plans		
	2002	2001	2000	2002	2001	2000
	(in millions)					
Service Cost	$ 72	$ 69	$ 60	$ 34	$ 30	$ 29
Interest Cost	241	232	227	114	114	106
Expected Return on Plan Assets	(337)	(338)	(321)	(62)	(61)	(57)
Amortization of Transition (Asset) Obligation	(9)	(8)	(8)	29	30	41
Amortization of Prior-service Cost	(1)	-	13	-	-	-
Amortization of Net Actuarial (Gain) Loss	(10)	(24)	(39)	27	18	4
Net Periodic Benefit Cost (Credit)	(44)	(69)	(68)	142	131	123
Curtailment Loss (a)	-	-	-	-	1	79
Net Periodic Benefit Cost (Credit) after Curtailments	$ (44)	$ (69)	$ (68)	$142	$132	$202

(a) Curtailment charges were recognized during 2000 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			U.S. OPEB Plans		
	2002	2001	2000	2002	2001	2000
	%	%	%	%	%	%
Discount Rate	6.75	7.25	7.50	6.75	7.25	7.50
Expected Return on Plan Assets	9.00	9.00	9.00	8.75	8.75	8.75
Rate of Compensation Increase	3.7	3.7	3.2	N/A	N/A	N/A

In determining the discount rate in the calculation of future pension obligations we review the interest rates of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. As a result of a decrease in this benchmark rate during 2002, we determined that a decrease in our discount rate from 7.25% at December 31, 2001 to 6.75% at December 31, 2002 was appropriate.

For OPEB measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003. The rate was assumed to decrease gradually each year to a rate of 5% through 2008 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	$ 21	$ (17)
Effect on the health care component of the accumulated postretirement benefit obligation	237	(193)

AEP Savings Plans

AEP sponsors various defined contribution retirement savings plans eligible to substantially all non-United Mine Workers of America (UMWA) U.S. employees. These plans include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. Beginning in 2001, AEP's contributions to the two largest plans increased to 75 cents for every dollar of the first 6% of eligible employee compensation from the previous rate of 50 cents. The cost for contributions to these plans totaled $60.1 million in 2002, $55.6 million in 2001 and $36.8 million in 2000.

On January 1, 2003, the two major AEP Savings Plans merged into a single plan.

Other UMWA Benefits

AEP and OPCo, a subsidiary company, provide 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 2002, 2001 and 2000. In July 2001, OPCo sold certain coal mines in Ohio and West Virginia.

15. Stock-Based Compensation:

The American Electric Power System 2000 Long-Term Incentive Plan was approved by shareholders at the Company's annual meeting in 2000 and authorizes the use of 15,700,000 shares of AEP common stock for various types of stock-based compensation awards, including stock option awards, to key employees. The plan was adopted in 2000.

Under the plan, the exercise price of all stock option grants must equal or exceed the market price of AEP's common stock on the date of grant. AEP generally grants options that have a ten-year life and vest, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st following the first, second and third anniversary of the grant date.

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. Outstanding CSW stock options will continue in effect until all options are exercised, cancelled or expired. Under the CSW stock option plan, the option price was equal to the fair market value of the stock on the grant date. All CSW options fully vested upon the completion of the merger and expire 10 years after their original grant date.

A summary of stock option transactions in fiscal periods 2002, 2001 and 2000 is as follows:

	2002		2001		2000	
	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	6,822	$37	6,610	$36	825	$40
Granted	2,923	$27	645	$45	6,046	$36
Exercised	(600)	$36	(216)	$38	(26)	$36
Forfeited	(358)	$41	(217)	$37	(235)	$39
Outstanding at end of year	8,787	$34	6,822	$37	6,610	$36
Options exercisable at end of year	2,481	$36	395	$43	588	$41
Weighted average Exercise price of options:						
-Granted above Market Price		$27		-		-
-Granted at Market Price		$27		$45		$36

The following table summarizes information about stock options outstanding at December 31, 2002:

Options Outstanding

Range of Exercise Prices	Number Outstanding	Life in Years	Exercise Price
$27.06-35.625	8,047,058	8.4	$ 32.54
40.69-49.00	739,483	7.1	44.84
$27.06-49.00	8,786,541	8.3	$ 33.58

Options Exercisable

Range of Exercise Prices	Number Outstanding	Weighted-Average Exercise Price
$27.06-35.625	2,230,000	$35.51
40.69-49.00	251,327	43.66
$27.06-49.00	2,481,327	$36.33

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 in the following table:

	2002	2001	2000
	(in millions except per share amounts)		
Net (loss) income:			
As reported	$ (519)	$ 971	$ 267
Pro forma	(528)	959	264
Basic (loss) earnings per share:			
As reported	$(1.57)	$3.01	$0.83
Pro forma	(1.59)	2.98	0.82
Diluted (loss) earnings per share:			
As reported	$(1.57)	$3.01	$0.83
Pro forma	(1.59)	2.97	0.82

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:

	2002	2001	2000
Risk Free Interest Rate	3.53%	4.87%	5.02%
Expected Life	7 years	7 years	7 years
Expected Volatility	29.78%	28.40%	24.75%
Expected Dividend Yield	6.15%	6.05%	6.02%
Weighted average fair value of options:			
-Granted above Market Price	$4.58	-	-
-Granted at Market Price	$4.37	$8.01	$5.50

16. Business Segments:

In 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 and 2002, we moved toward a goal of functionally and structurally separating 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
- Gas pipeline and storage services
- Marketing and trading of electricity, gas, coal and other commodities
- Coal mining, bulk commodity barging operations and other energy supply related businesses

Energy Delivery
- Domestic electricity transmission
- Domestic electricity distribution

Other
- Energy services

Segment results of operations for the twelve months ended December 31, 2002, 2001 and 2000 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 income and deductions from income. It differs from net income in that it does not take into account interest expense, income taxes and the effect of discontinued operations, extraordinary items and the cumulative effect of a change in accounting principle. EBIT is believed to be a reasonable gauge of results of operations. By excluding interest expense 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 Statements of Operations. By excluding discontinued operations, extraordinary items, and the cumulative effect of changes in accounting principles, EBIT gives more focused guidance on segment operating performance.

Year	Wholesale	Energy Delivery	Other	Reconciling Adjustments	AEP Consolidated
		(in millions)			
2002					
Revenues from:					
External unaffiliated customers	$10,988	$ 3,551	$ 16	$ -	$14,555
Transactions with other operating segments	2,314	20	46	(2,380)	-
Segment EBIT	645	970	(549)	-	1,066
Depreciation, depletion and amortization expense	842	519	16	-	1,377
Total assets	22,622	11,624	248	247(a)	34,741
Investments in equity method subsidiaries	115	-	57	-	172
Gross property additions	1,072	638	12	-	1,722
2001					
Revenues from:					
External unaffiliated customers	$ 9,297	$ 3,356	$ 114	$ -	$12,767
Transactions with other operating segments	2,708	20	1,155	(3,883)	-
Segment EBIT	1,302	986	42	-	2,330
Depreciation, depletion and amortization expense	597	632	14	-	1,243
Total assets	21,947	12,455	220	4,675(a)	39,297
Investments in equity method subsidiaries	242	-	370	-	612
Gross property additions	610	844	200	-	1,654
2000					
Revenues from:					
External unaffiliated customers	$ 7,834	$ 3,174	$ 105	$ -	$11,113
Transactions with other operating segments	1,726	2	750	(2,478)	-
Segment EBIT	686	1,017	89	-	1,792
Depreciation, depletion and amortization expense	556	506	29	-	1,091
Total assets	24,172	14,876	2,625	4,960(a)	46,633
Investments in equity method subsidiaries	140	-	296	-	436
Gross property additions	366	961	141	-	1,468

(a) Reconciling adjustments for Total Assets include Assets Held for Sale and/or Assets of Discontinued Operations.

17. 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 Executive Committee and are administered by the Chief Risk Officer. The Risk Executive 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. of 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	Trading and hedging
Credit Risk	Non-performance on contracts with counterparties	Guarantees and 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 other commodities and as a result we are subject to price risk. The amount of risk taken by the traders is controlled by the management of the trading operations and the Chief Risk Officer and his staff. If the risk from trading activities exceeds certain pre-determined limits, the positions are modified or hedged to reduce the risk to be within the limits unless specifically approved by the Risk Executive Committee.

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 a settlement agreement in Michigan, capped in Indiana and fixed (subject to future commission action) in West Virginia. To the extent all fuel supply for 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 Arkansas, Kentucky, Louisiana, Oklahoma, Virginia and the SPP area of Texas.

We enter into currency and interest rate forward and swap transactions to hedge the currency and interest rate exposures created by commodity transactions. These transactions are marked-to-market to match the change in value in the transactions they hedge which are also marked-to-market. We employ forward contracts as cash flow hedges and swaps as cash flow or fair value hedges to mitigate changes in interest rates or fair values on Short-Term Debt 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.

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 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.

Option 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, the implied volatility curve and the implied correlation curve. Volatility and correlation prices may be quoted in the market. Significant estimates in valuing these contracts include forward price curves, volumes, and other volatilities.

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

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. When this occurs, we use our best judgment to estimate the curve values. 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 curve to the market. All fair value amounts are net of adjustments for items such as credit quality of the counterparty (credit risk) and liquidity risk.

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.

Results of Risk Management Activities

The amounts of net revenue margins (sales less purchases) in 2002, 2001, and 2000 for trading activities were:

	2002	2001	2000
		(in millions)	
Net Revenue Margins	$53	$402	$233

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 internally developed price curves for open long-term trading contracts. The following table does not reflect derivative contracts designated as hedges or firm transmission rights contracts. As a result, the totals will not agree to the Consolidated Balance Sheets. The fair values of trading contracts at December 31 are:

	2002 Fair Value (in millions)	2001 Fair Value (in millions)
Trading Assets		
Electricity and Other		
Physicals	$ 846	$ 966
Financials	226	170
Total Trading Assets	$1,072	$ 1,136
Gas		
Physicals	$ 105	$ 196
Financials	685	1,587
Total Trading Assets	$ 790	$ 1,783
Trading Liabilities		
Electricity and Other		
Physicals	$ (534)	$ (760)
Financials	(126)	(87)
Total Trading Liabilities	$ (660)	$ (847)
Gas		
Physicals	$ (191)	$ (38)
Financials	(761)	(1,586)
Total Trading Liabilities	$ (952)	$(1,624)

Credit Risk

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 counterparties depending upon credit quality 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 are not material to our financial condition at December 31, 2002. At December 31, 2002, less than 7% of our exposure was below investment grade as expressed in terms of Net Mark to Market Assets. Net Mark to Market Assets represents the aggregate difference between the forward market price for the remaining term of the contract and the contractual price per counterparty. The following table approximates counterparty credit quality and exposure for AEP based on netting across AEP entities, commodities and instruments.

Counterparty Credit Quality: Year Ending December 31, 2002	Futures, Forward and Swap Contracts	Options	Total
		(in millions)	
AAA/Exchanges	$ 26	$ 2	$ 28
AA	307	33	340
A	448	26	474
BBB	700	101	801
Below Investment Grade	107	11	118
Total	$1,588	$173	$1,761

We enter into transactions for electricity and natural gas as part of wholesale trading operations. Electricity 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 U.S. 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, 2002 and 2001 were $109 million and $55 million. These margin accounts are restricted and therefore are not included in Cash and Cash Equivalents on the Consolidated Balance Sheets. AEP and its subsidiaries 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. 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.

Certain derivatives may be designated for accounting purposes as a hedge of either the fair value of an asset, liability, 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 to determine whether the hedge will be or 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 the 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. 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 (Loss) on the Consolidated Balance Sheets at December 31, 2002 are:

	Hedging Assets	Hedging Liabilities (in millions)	Accumulated Other Comprehensive Income (Loss) After Tax
Electricity and Gas	$6	$ (8)	$ (2)
Interest Rate	-	(13)*	(12)
Foreign Currency	-	(2)	(2)
			$(16)

* Includes $6 million loss recorded in an equity investment.

The following table represents the activity in Other Comprehensive Income (Loss) related to the effect of adopting SFAS 133 for derivative contracts that qualify as cash flow hedges at December 31, 2002:

	(in millions)
AEP Consolidated	
Beginning Balance, January 1, 2002	$ (3)
Changes in fair value	(56)
Reclasses from OCI to net loss	43
Accumulated OCI derivative loss, December 31, 2002	$(16)

Approximately $9 million of net losses from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2002 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 five years.

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 for AEP at December 31, 2002 and 2001 are summarized in the following tables.

	2002		2001	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)		(in millions)	
Long-term Debt	$10,125	$10,470	$9,505	$9,542
Preferred Stock	84	77	95	93
Trust Preferred Securities	321	324	321	321

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 "Accounting for Certain Investments in Debt and Equity Securities". At December 31, 2002 and 2001, the fair values of the trust investments were $969 million and $933 million, respectively, and had a cost basis of $909 million and $839 million, respectively. The change in market value in 2002, 2001, and 2000 was a net unrealized holding loss of $33 million and $11 million and a net unrealized holding gain of $6 million, respectively.

18. Income Taxes:

The details of AEP's consolidated income taxes before discontinued operations, extraordinary items, and cumulative effect as reported are as follows:

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
Federal:			
Current	$ 330	$404	$ 793
Deferred	(192)	60	(236)
Total	138	464	557
State:			
Current	32	61	47
Deferred	30	34	(6)
Total	62	95	41
International:			
Current	13	(13)	4
Deferred	1	-	-
Total	14	(13)	4
Total Income Tax as Reported Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$ 214	$546	$ 602

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

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
Net Income (Loss)	$(519)	$ 971	$267
Discontinued Operations (net of income tax of $73 million in 2002, $22 million in 2001 and $5 million in 2000)	190	(86)	(122)
Extraordinary Items (net of income tax of $20 million in 2001 and $44 million in 2000)	-	50	35
Cumulative Effect of Accounting Change (net of income tax of $2 million in 2001)	350	(18)	-
Preferred Stock Dividends	11	10	11
Income Before Preferred Stock Dividends of Subsidiaries	32	927	191
Income Taxes Before Discontinued Operations, Extraordinary Items and Cumulative Effect	214	546	602
Pre-Tax Income	$ 246	$1,473	$793
Income Taxes on Pre-Tax Income at Statutory Rate *(35%)*	$ 86	$ 516	$278
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	32	48	77
Corporate Owned Life Insurance	-	4	247
Investment Tax Credits (net)	(35)	(37)	(36)
Tax Effects of International Operations	123	(12)	(1)
Energy Production Credits	(14)	-	-
Merger Transaction Costs	-	-	49
State Income Taxes	40	62	26
Other	(18)	(35)	(38)
Total Income Taxes as Reported before Discontinued Operations, Extraordinary Items and Cumulative Effect	$ 214	$ 546	$602
Effective Income Tax Rate	87.0%	37.1%	75.9%

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

	December 31,	
	2002	2001
	(in millions)	
Deferred Tax Assets	$ 2,189	$ 1,216
Deferred Tax Liabilities	(6,105)	(5,716)
Net Deferred Tax Liabilities	$(3,916)	$(4,500)
Property Related Temporary Differences	$(3,612)	$(3,674)
Amounts Due From Customers For Future Federal Income Taxes	(360)	(245)
Deferred State Income Taxes	(422)	(314)
Transition Regulatory Assets	(234)	(268)
Regulatory Assets Designated for Securitization	(310)	(332)
Asset Impairments and Investment Value Losses	417	-
Deferred Income Taxes on Other Comprehensive Loss	326	3
All Other (net)	279	330
Net Deferred Tax Liabilities	$(3,916)	$(4,500)

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.

19. Basic and Diluted Earnings Per Share:

The calculation of basic and diluted earnings (loss) per common share (EPS) is based on the amounts of Net Income (Loss) and weighted average common shares shown in the table below:

	2002	2001	2000
	(in millions - except per share amounts)		
Income:			
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$ 21	$ 917	$ 180
Discontinued Operations	(190)	86	122
Income (Loss) Before Extraordinary Item And Cumulative Effect	(169)	1,003	302
Extraordinary Losses (net of tax):			
Discontinuance of Regulatory Accounting For Generation	-	(48)	(35)
Loss on Reacquired Debt	-	(2)	-
Cumulative Effect of Accounting Change (net of tax)	(350)	18	-
Net Income (Loss)	$(519)	$ 971	$ 267
Weighted Average Shares:			
Average Common Shares Outstanding	332	322	322
Assumed Conversion of Dilutive Stock Options (see Note 15)	-	1	-
Diluted Average Common Shares Outstanding	332	323	322
Basic and Diluted Earnings Per Common Share:			
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	$ 0.06	$2.85	$0.56
Discontinued Operations	(0.57)	0.26	0.38
Income (Loss) Before Extraordinary Item and Cumulative Effect	(0.51)	3.11	0.94
Extraordinary Losses (net of tax):			
Discontinuance of Regulatory Accounting For Generation	-	(0.15)	(0.11)
Loss on Reacquired Debt	-	(0.01)	-
Cumulative Effect of Accounting Change (net of tax)	(1.06)	0.06	-
	$(1.57)	$3.01	$0.83

The assumed conversion of stock options does not affect net earnings (loss) for purposes of calculating diluted earnings per share. Basic and diluted EPS are the same in 2002, 2001 and 2000 since the effect on weighted average common shares outstanding is minimal.

Had AEP recognized net income in fiscal 2002, incremental shares attributable to the assumed exercise of outstanding stock options would have increased diluted common shares outstanding by 398,000 shares.

Options to purchase 8.8 million, 0.7 million and 6.4 million shares of common stock were outstanding at December 31, 2002, 2001 and 2000, respectively, but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the year-end market price of the common shares and, therefore, the effect would be antidilutive.

In addition, there is no effect on diluted earnings per share related to our equity units (issued in 2002) unless the market value of AEP common stock exceeds $49.08 per share. There were no dilutive effects from equity units at December 31, 2002. If our common stock value exceeds $49.08 we would apply the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contracts are used to repurchase outstanding shares. Also see Note 27.

20. Supplementary Information:

	Year Ended December 31,		
	2002	2001	2000
	(in millions)		
AEP Consolidated Purchased Power – Ohio Valley Electric Corporation (44.2% owned by AEP System)	$142	$127	$86
Cash was Paid for:			
Interest (net of capitalized amounts)	792	972	842
Income Taxes	336	569	449
Noncash Investing and Financing Activities:			
Acquisitions under Capital Leases	6	17	118
Assumption of Liabilities Related to Acquisitions	1	171	-
Exchange of Communication Investment for Common Stock	-	5	-

21. Power and Distribution 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 1,113 MW.

Investments in power projects that are 50% or less owned are accounted for by the equity method and reported in Investments in Power and Distribution Projects on the Consolidated Balance Sheets (see "Eastex" within the Assets Held for Sale section of Note 13), except for Eastex Cogeneration which, due to its structure, is consolidated. At December 31, 2002, six domestic power projects and three international power investments 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 either Qualifying Facilities (QFs) or Exempt Wholesale Generators (EWGs) under PURPA. The three international power investments are classified as Foreign Utility Companies (FUCO) under the Energy Policies Act of 1992. Two of the international investments are power projects and the other international investment is a company which owns an interest in four additional power projects. All of the power projects accounted for under the equity method have unrelated third-party partners.

Seven of the above power projects have project-level financing, which is non-recourse to AEP. AEP or AEP subsidiaries have guaranteed $58 million of domestic partnership obligations for performance under power purchase agreements and for debt service reserves in lieu of cash deposits.

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. In December 2002, AEP recorded an other than temporary impairment totaling $141.1 million (after federal income tax benefit of $76 million) of its 44% equity investment in Vale and its 20% equity interest in Caiua. See "Grupo Rede Investment" within the Investment Values section of Note 13 "Asset Impairments and Investment Value Losses", for further information on the 2002 impairment of our Vale and Caiua investments.

22. Leases:

Leases of property, plant and equipment are for periods up to 99 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 generally 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 rental costs are as follows:

	Year Ended December 31,		
	2002	2001	2000
	(in millions)		
Lease Payments on Operating Leases	$346	$293	$246
Amortization of Capital Leases	65	82	118
Interest on Capital Leases	14	22	36
Total Lease Rental Costs	$425	$397	$400

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

	December 31, 2002	2001
	(in millions)	
Property, Plant and Equipment:		
Production	$ 40	$ 39
Distribution	15	15
Other	687	723
Total Property, Plant and Equipment	742	777
Accumulated Amortization	299	250
Net Property, Plant and Equipment	$443	$527
Obligations Under Capital Leases:		
Noncurrent Liability	$170	$219
Liability Due Within One Year	58	75
Total	$228	$294

Future minimum lease payments consisted of the following at December 31, 2002

	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2003	$ 70	$ 305
2004	53	271
2005	37	252
2006	29	242
2007	21	237
Later Years	59	2,462
Total Future Minimum Lease Payments	269	$3,769
Less Estimated Interest Element	41	
Estimated Present Value of Future Minimum Lease Payments	$228	

OPCo has entered into an agreement with JMG Funding LLP (JMG) an unrelated unconsolidated special purpose entity. JMG has a capital structure of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from pollution control bonds and other bonds. JMG owns the Gavin Scrubber and leases it to OPCo. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. Payments under the operating lease are based on JMG's cost of financing (both debt and equity) and include an amortization component plus the cost of administration. Neither OPCo nor AEP has an ownership interest in JMG and does not guarantee JMG's debt.

At any time during the lease, OPCo has the option to purchase the Gavin Scrubber for the greater of its fair market value or adjusted acquisition cost (equal to the unamortized debt and equity of JMG) or sell the Gavin Scrubber. The initial 15-year lease term is non-cancelable. At the end of the initial term, OPCo can renew the lease, purchase the Gavin Scrubber (terms previously mentioned), or sell the Gavin Scrubber. In case of a sale at less than the adjusted acquisition cost, OPCo must pay the difference to JMG.
The use of JMG allows AEP to enter into an operating lease while keeping the tax benefits otherwise associated with a capital lease. As of December 31, 2002, unless the structure of this arrangement is changed, it is reasonably possible that AEP will consolidate JMG in the third quarter of 2003 as a result of the issuance of FIN 46. Upon consolidation, AEP would record the assets, liabilities, depreciation expense, minority interest and debt interest expense of JMG. AEP would eliminate operating lease expense. AEP's maximum exposure to loss as a result of its involvement with JMG is approximately $560 million of outstanding debt and equity of JMG as of December 31, 2002.

AEGCo and I&M entered into a sale and leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee) an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the plant). Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the plant and leases it to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the lease footnote. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the plant. AEGCo, I&M nor AEP has ownership interest in the Owner Trustee and do not guarantee its debt.

23. Lines of Credit and Sale of Receivables:

Lines of Credit – AEP System

The AEP System uses short-term debt, primarily commercial paper and revolving credit facilities, to meet fluctuations in working capital requirements and other interim capital needs. AEP has established a utility money pool and a non-utility money pool to coordinate short-term borrowings for certain subsidiaries. AEP also incurs borrowings outside of the money pool for other subsidiaries. As of December 31, 2002, AEP had revolving credit facilities totaling $3.5 billion to support its commercial paper program. At December 31, 2002, AEP had $3.2 billion outstanding in short-term borrowings of which $1.4 billion was commercial paper supported by the revolving credit facilities. The maximum amount of commercial paper outstanding during the year, which had a weighted average interest rate during 2002 of 2.47%, was $3.3 billion during April 2002. On December 11, 2002, Moody's Investor Services placed AEP's Prime-2 short-term rating for commercial paper under review for possible downgrade. On January 24, 2003, Standard & Poor's Rating Services placed AEP's A-2 short-term rating for commercial paper under review for possible downgrade. On February 10, 2003, Moody's Investor Services downgraded AEP's short-term rating for commercial paper to Prime-3 from Prime-2. As a result, AEP's access to the commercial paper market will be limited and AEP will use other sources of funds as necessary.

Outstanding Short-term Debt for AEP Consolidated consisted of:

	December 31, 2002	December 31, 2001
	(in millions)	
Balance Outstanding:		
Notes Payable	$1,747	$1,063
Commercial paper	1,417	2,948
Total	$3,164	$4,011

Sale of Receivables – AEP Credit

AEP Credit entered into a sale of receivables agreement with a group of banks and commercial paper conduits. Under the sale of receivables agreement, which expires May 28, 2003, AEP Credit sells an interest in the receivables it acquires 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 and allowing AEP Credit to repay any debt obligations. 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. This off-balance sheet transaction was entered into to allow AEP credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate its cash collections.

At December 31, 2002, the sale of receivables agreement provided the banks and commercial paper conduits would purchase a maximum of $600 million of receivables from AEP Credit, of which $454 million was outstanding. As collections from receivables sold occur and are remitted, the outstanding balance for sold receivables is reduced and as new receivables are sold, the outstanding balance of sold receivables increases. All of the receivables sold represented affiliate receivables. The commitment's new term under the sale of receivables agreement will remain at $600 million until May 28, 2003. 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 receivables less an allowance for anticipated uncollectible accounts.

AEP Credit purchases accounts receivable through purchase agreements with affiliated companies and, until the first quarter of 2002, with non-affiliated companies. As a result of the restructuring of electric utilities in the State of Texas, the purchase agreement between AEP Credit and Reliant Energy, Incorporated was terminated as of January 25, 2002 and the purchase agreement between AEP Credit and Texas-New Mexico Power Company, the last remaining non-affiliated company, was terminated on February 7, 2002. In addition, the purchase agreements between AEP Credit and its Texas affiliates AEP Texas Central Company (formerly Central Power and Light Company) and AEP Texas North Company (formerly West Texas Utilities Company) were terminated effective March 20, 2002.

Comparative accounts receivable information for AEP Credit:

	Year Ended December 31, 2002	2001
	(in millions)	
Proceeds from Sale of Accounts Receivable	$5,513	$1,134
Accounts Receivable Retained Interest Less Uncollectible Accounts and Amounts Pledged as Collateral	76	143
Deferred Revenue from Servicing Accounts Receivable	1	5
Loss on Sale of Accounts Receivable	4	8
Average Variable Discount Rate	1.92%	2.28%
Retained Interest if 10% Adverse Change in Uncollectible Accounts	74	142
Retained Interest if 20% Adverse Change in Uncollectible Accounts	72	140

Historical loss and delinquency amount for the AEP System's customer accounts receivable managed portfolio:

	Face Value Year Ended December 31, 2002	2001
	(in millions)	
Customer Accounts Receivable Retained	$ 466	$ 343
Miscellaneous Accounts Receivable Retained	1,394	1,365
Allowance for Uncollectible Accounts Retained	(119)	(69)
Total Net Balance Sheet Accounts Receivable	1,741	1,639
Customer Accounts Receivable Securitized (Affiliate)	454	560
Customer Accounts Receivable Securitized (Non-Affiliate)	-	485
Total Accounts Receivable Managed	$2,195	$2,684
Net Uncollectible Accounts Written Off	$ 49	$ 87

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

At December 31, 2002, delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors was $30 million.

24. Unaudited Quarterly Financial Information:

The unaudited quarterly financial information for AEP Consolidated follows:

(In Millions - Except Per Share Amounts)	2002 Quarterly Periods Ended March 31	June 30	Sept. 30	Dec. 31
Revenues	$ 3,169	$ 3,575	$ 3,870	$ 3,941
Operating Income (Loss)	459	427	782	(405)
Income (Loss) Before Discontinued Operations, Extraordinary Items and Cumulative Effect	159	158	386	(682)
Net Income (Loss)	(169)	62	425	(837)
Earnings (Loss) per Share Before Discontinued Operations, Extraordinary Items And Cumulative Effect*	0.49	0.49	1.14	(2.01)
Earnings (Loss) per Share**	(0.53)	0.19	1.25	(2.47)

(In Millions - Except Per Share Amounts)	2001 Quarterly Periods Ended March 31	June 30	Sept. 30	Dec. 31
Revenues	$2,910	$3,259	$ 3,733	$ 2,865
Operating Income	521	622	824	215
Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect	230	251	399	37
Net Income	266	232	421	52
Earnings per Share Before Discontinued Operations, Extraordinary Items and Cumulative Effect***	0.72	0.77	1.23	0.12
Earnings per Share****	0.83	0.72	1.31	0.16

* Amounts for 2002 do not add to $0.06 earnings per share before discontinued operations, extraordinary items and cumulative effect due to rounding and the dilutive effect of shares issued in 2002.

**Amounts for 2002 do not add to $(1.57) earnings per share due to rounding.

***Amounts for 2001 do not add to $2.85 earnings per share before discontinued operations, extraordinary items and cumulative effect due to rounding.

****Amounts for 2001 do not add to $3.01 earnings per share due to rounding.

Income Before Discontinued Operations, Extraordinary Items and Cumulative Effect for the fourth quarter 2002 decreased $896 million from the prior year due to the impairment loss and impairment value losses of approximately $1,188 million (pre-tax) to reduce the valuation of under-performing assets. In addition to the impairments that were booked during the fourth quarter, a change in other comprehensive income of $585 million for pension liability had a negative effect on the Consolidated Balance Sheets.

25. Trust Preferred Securities:

The following Trust Preferred Securities issued by the wholly-owned statutory business trusts of PSO, SWEPCo and TCC were outstanding at December 31, 2002 and December 31, 2001. They are classified on the Consolidated 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. TCC reacquired 490,000 trust preferred units during 2001.

Business Trust	Security	Units Issued/ Outstanding At 12/31/02	Amount at December 31, 2002	2001	Description of Underlying Debentures of Registrant
			(in millions)		
CPL Capital I	8.00%, Series A	5,450,000	$136	$136	TCC, $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	$321	

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.

26. Minority Interest in Finance Subsidiary:

In August 2001 AEP formed AEP Energy Services Gas Holding Co. II, LLC (SubOne) and Caddis Partners, LLC (Caddis). SubOne is a wholly owned consolidated subsidiary of AEP that was capitalized with the assets of Houston Pipe Line Company, Louisiana Interstate Gas Company (AEP subsidiaries) and $321.4 million of AEP Energy Services Gas Holding Company (AEP Gas Holding is an AEP subsidiary and parent of SubOne) preferred stock, that is convertible into AEP common stock at market price on a dollar-for-dollar basis. Caddis was capitalized with $2 million cash and a subscription agreement that represents an unconditional obligation to fund $83 million from SubOne and $750 million from Steelhead Investors LLC ("Steelhead" - non-controlling preferred member interest). As managing member, SubOne consolidates Caddis. Steelhead is an unconsolidated special purpose entity and has a capital structure of $750 million of which 3% is equity from investors with no relationship to AEP or any of its subsidiaries and 97% is debt from a syndicate of banks. The use of Steelhead allows AEP to limit its risk associated with Houston Pipe Line Company and Louisiana Intrastate Gas Company.

Under the provisions of the Caddis formation agreements, Steelhead receives a quarterly preferred return equal to an adjusted floating reference rate (4.784% and 4.413% for the quarters ended December 31, 2002 and 2001, respectively). Caddis has the right to redeem Steelhead's interest at any time.

The $750 million invested in Caddis by Steelhead was loaned to SubOne. This intercompany loan to SubOne is due August 2006, and is supported by the natural gas pipeline assets of SubOne, a cash reserve fund of SubOne and SubOne's $321.4 million of preferred stock in AEP Gas Holding. The preferred stock is convertible into AEP common stock upon the occurrence of certain events including AEP's stock price closing below $18.75 for ten consecutive trading days. AEP can elect not to have the transaction supported by such preferred stock if SubOne were to reduce its loan with Caddis by $225 million. The credit agreement between Caddis and SubOne contains covenants that restrict certain incremental liens and indebtedness, asset sales, investments, acquisitions, and distributions. The credit agreement also contains covenants that impose minimum financial ratios. Non-performance of these covenants may result in an event of default under the credit agreement. Through December 31, 2002, we have complied with the covenants contained in the credit agreement. In addition, a default under any other agreement or instrument relating to AEP and certain subsidiaries' debt outstanding in excess of $50 million is an event of default under the credit agreement.

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

Steelhead has certain rights as a preferred member in 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 AEP Gas Holding preferred stock into AEP common stock. If Steelhead exercised its rights to force Caddis to liquidate under these conditions, then AEP would evaluate whether to refinance at that time or relinquish the assets that support the intercompany loan to Caddis. Liquidation of Caddis could negatively impact AEP's liquidity.

Caddis and SubOne 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 SubOne are consolidated with AEP for financial reporting purposes. Steelhead's investment in Caddis and payments made to Steelhead from Caddis are currently reported on AEP's income statement and balance sheet as Minority Interest in Finance Subsidiary.

AEP's maximum exposure to loss as a result of its involvement with Steelhead is $321.4 million of preferred stock, $83 million under the subscription agreement to Caddis for any losses incurred by Caddis and the cash reserve fund balance of $34 million (as of December 31, 2002) due Caddis for default under the intercompany loan agreement. AEP can reduce its maximum exposure related to the preferred stock by a reduction of $225 million of the intercompany loan.

As of December 31, 2002, we are continuing to review the application of FIN 46 as it relates to the Steelhead transaction.

27. Equity Units

In June 2002, AEP issued 6.9 million equity units at $50 per unit and received proceeds of $345 million. Each equity unit consists of a forward purchase contract and a senior note.

The forward purchase contracts obligate the holders to purchase shares of AEP common stock on August 16, 2005. The purchase price per equity unit is $50. The number of shares to be purchased under the forward purchase contract will be determined under a formula based upon the average closing price of AEP common stock near the stock purchase date. Holders may satisfy their obligation to purchase AEP common stock under the forward purchase contracts by allowing the senior notes to be remarketed or by continuing to hold the senior notes and using other resources as consideration for the purchase of stock. If the holders elect to allow the notes to be remarketed, the proceeds from the remarketing will be used to purchase a portfolio of U.S. treasury securities that the holders will pledge to AEP in order to meet their obligations under the forward purchase contracts.

The senior notes have a principal amount of $50 each and mature on August 16, 2007. The senior notes are the collateral that secures the holders' requirement to purchase common stock under the forward purchase contracts.

AEP will make quarterly interest payments on the senior notes at the initial annual rate of 5.75%. The interest rate can be reset through a remarketing, which is initially scheduled for May 2005. AEP will make contract adjustment payments to the purchaser at the annual rate of 3.50% on the forward purchase contracts. The present value of the contract adjustment payments has been recorded as a $31 million liability in Equity Unit Senior Notes offset by a charge to Paid-in Capital. Interest payments on the senior notes are reported as interest expense. Accretion of the contract adjustment payment liability is reported as interest expense.

AEP applies the treasury stock method to the equity units to calculate diluted earnings per share. This method of calculation theoretically assumes that the proceeds received as a result of the forward purchase contract are used to repurchase outstanding shares.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Schedule of Consolidated Cumulative Preferred Stocks of Subsidiaries

	December 31, 2002			
	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	608,150	$ 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	51
Total Subject to Mandatory Redemption (c)				84
Total Preferred Stock				$145

	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
Total Preferred Stock				$156

NOTES TO SCHEDULE OF CONSOLIDATED 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, 2002 the subsidiaries had 13,749,202, 22,200,000 and 7,713,501 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.
(d) Not callable prior to 2003, after that the call price is $100 per share plus accrued dividends.
(e) With sinking fund.
(f) The number of shares of preferred stock redeemed is 106,458 shares in 2002, 50,000 shares in 2001 and 209,563 shares in 2000.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
Schedule of Consolidated Long-term Debt of Subsidiaries

Maturity	Weighted Average Interest Rate December 31, 2002	Interest Rates at December 31, 2002	Interest Rates at December 31, 2001	December 31, 2002 (in millions)	December 31, 2001 (in millions)
FIRST MORTGAGE BONDS (a)					
2002-2004	6.87%	6.00%-7.85%	6.00%-7.85%	$ 648	$ 1,246
2005-2008	6.90%	6.20%-8%	6.20%-8%	463	699
2022-2025	7.66%	6.875%-8.7%	6-7/8%-8.80%	773	850
INSTALLMENT PURCHASE CONTRACTS (b)					
2002-2009	4.62%	3.75%-7.70%	1.80%-7.70%	396	446
2011-2030	5.83%	1.35%-8.20%	1.55%-8.20%	1,284	1,234
NOTES PAYABLE (c)					
2002-2021	5.54%	3.732%-9.60%	4.048%-9.60%	520	217
SENIOR UNSECURED NOTES					
2002-2005	5.53%	2.12%-7.45%	2.31%-7.45%	1,834	1,910
2006-2012	5.91%	4.31%-6.91%	6.125%-6.91%	2,295	1,727
2032-2038	6.64%	6.00%-7-3/8%	7.20%-7-3/8%	690	340
JUNIOR DEBENTURES					
2025-2038	7.90%	7.60%-8.72%	7.60%-8.72%	205	618
SECURITIZATION BONDS					
2003-2016	5.40%	3.54%-6.25%	-	797	-
OTHER LONG-TERM DEBT (d)				247	258
Unamortized Discount (net)				(32)	(40)
Total Long-term Debt Outstanding				10,120	9,505
Less Portion Due Within One Year				1,633	1,095
Long-term Portion				$ 8,487	$ 8,410
EQUITY UNIT SENIOR NOTES					
2007	5.75%	5.75%	-	$ 376	$ -

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 consists of a liability along with accrued interest for disposal of spent nuclear fuel (see Note 9 of the Notes to Consolidated Financial Statements) and financing obligation under sale lease back agreements.

Long-term debt outstanding at December 31, 2002
(includes Equity Unit Senior Notes) is payable as follows:

	(in millions)
2003	$ 1,633
2004	824
2005	993
2006	1,611
2007	1,081
Later Years	4,386
	10,528
Unamortized Discount	32
Total	$10,496

MANAGEMENT'S RESPONSIBILITY

The management of American Electric Power Company, Inc. has prepared the financial statements and schedules herein and 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 United States of America, 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 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 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 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 accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of operations, cash flows and common shareholders' equity and comprehensive income, for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Company adopted SFAS 142, "Goodwill and Other Intangible Assets," effective January 1, 2002.

As discussed in Note 13 to the consolidated financial statements, the Company recorded certain impairments of goodwill, long-lived assets and other investments in the fourth quarter of 2002.

Deloitte & Touche LLP

Deloitte & Touche LLP
Columbus, Ohio
February 21, 2003

INVESTOR INQUIRIES

Investors should direct inquiries to Investor Relations using the toll free number, 1-800-237-2667 or by writing to:

Bette Jo Rozsa
Managing Director of Investor Relations
American Electric Power Service Corporation
28th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

FORM 10-K ANNUAL REPORT

The Annual Report (Form 10-K) to the Securities and Exchange Commission will be available in April 2003 at no cost to shareholders. Please address requests for copies to:

R. Todd Rimmer
Director of Financial Reporting
American Electric Power Service Corporation
26th Floor
1 Riverside Plaza
Columbus, OH 43215-2373

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