APCo's 2009 Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo's March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of $320 million and a first-year increase of $112 million, effective October 2009.

In June 2010, the WVPSC approved a settlement agreement for $86 million, including $9 million of construction surcharges related to APCo's second year ENEC increase. The settlement agreement allows APCo to accrue a weighted average cost of capital carrying charge on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of accumulated deferred income taxes. The new rates became effective in July 2010.

In June 2011, the WVPSC issued an order approving an $88 million annual increase including $7 million of construction surcharges and $7 million of carrying charges related to APCo's third year ENEC increase. The order also allows APCo to accrue a fixed annual carrying cost rate of 4%. The new rates became effective in July 2011. Additionally, the order approved APCo's request to purchase the Dresden Plant from AEGCo and approved deferral of post in-service Dresden Plant costs, including a return, for future recovery. APCo purchased the Dresden Plant from AEGCo in August 2011 for $302 million. As of December 31, 2011, APCo's ENEC under-recovery balance of $359 million was recorded in Regulatory Assets on the balance sheet, excluding $7 million of unrecognized equity carrying costs. If the WVPSC were to disallow a portion of APCo's deferred ENEC costs, it could reduce future net income and cash flows and impact financial condition.

WPCo Merger with APCo

In a November 2009 proceeding established by the WVPSC to explore options to meet WPCo's future power supply requirements, the WVPSC issued an order approving a joint stipulation among APCo, WPCo, the WVPSC staff and the Consumer Advocate Division. The order approved the recommendation of the signatories to the stipulation that WPCo merge into APCo and be supplied from APCo's existing power resources. Merger approvals from the WVPSC, Virginia SCC and the FERC are required. In December 2011 and February 2012, APCo filed merger applications with the WVPSC and the FERC, respectively.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and the Oklahoma Industrial Energy Consumers (OIEC) recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate fuel transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. The testimony included unquantified refund recommendations relating to re-pricing of those ERCOT trading contracts. Hearings were held in June 2011. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

Michigan 2009 and 2010 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Cook Plant Unit 1 (Unit 1) outage from mid-December 2008 through December 2009, the period during which I&M received and recognized accidental outage insurance proceeds. In October 2010, a settlement agreement was filed with the MPSC which included deferring the Unit 1 outage issue to the 2010 PSCR reconciliation. In November 2011, the MPSC approved a settlement agreement for the 2010 PSCR reconciliation which resolved the Unit 1 outage issue by ordering no disallowances associated with the Unit 1 outage issue. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 5.

2011 Michigan Base Rate Case

In July 2011, I&M filed a request with the MPSC for an annual increase in Michigan base rates of $25 million and a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $6 million increase in annual depreciation expense. An interim rate increase of $16 million annually was implemented in January 2012, subject to refund.

In February 2012, the MPSC approved a settlement agreement which increased annual base rates by approximately $15 million, effective April 2012, based upon a return on common equity of 10.2% and included a $5 million annual increase in depreciation rates. The approved settlement agreement also excluded the Michigan jurisdictional share of the net costs of the Cook Plant Unit 1 (Unit 1) turbine replacement from rate base but provided for a return on and of the net cost as a regulatory asset, effective February 2012. As of December 31, 2011, the Michigan jurisdictional share of the net costs of the Unit 1 turbine replacement was $9 million. Future rate recovery of the regulatory asset will be reviewed in a future rate proceeding.

2011 Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The request included an increase in depreciation rates that would result in a $25 million increase in annual depreciation expense.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund – Affecting APCo, I&M and OPCo

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million. APCo's, I&M's and OPCo's portions of recognized gross SECA revenues are as follows:

Company	(in millions)	
APCo	$	70.2
I&M		41.3
OPCo		92.1

In 2006, a FERC Administrative Law Judge issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supported AEP's position and required a compliance filing to be filed with the FERC by August 2010.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. APCo's, I&M's and OPCo's portions of the provision are as follows:

Company	(in millions)
APCo	$ 14.1
I&M	8.3
OPCo	18.5

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of December 31, 2011 was $32 million. APCo's, I&M's and OPCo's reserve balances as of December 31, 2011 were:

Company	December 31, 2011
	(in millions)
APCo	$ 10.0
I&M	5.9
OPCo	13.2

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. A decision is pending from the FERC. APCo's, I&M's and OPCo's portions of potential refund payments and potential payments to be received are as follows:

Company	Potential Refund Payments	Potential Payments to be Received
	(in millions)	
APCo	$ 6.4	$ 3.2
I&M	3.7	1.9
OPCo	8.3	4.2

Based on the analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Possible Termination of the Interconnection Agreement – Affecting APCo, I&M and OPCo

In December 2010, each of the AEP Power Pool members gave notice to AEPSC and each other of their decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by FERC, subject to state regulatory input. In February 2012, an application was filed with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo. If any of the AEP Power Pool members experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows. As a result of the February 2012 ESP rehearing order, management is in the process of withdrawing the PUCO and FERC applications. See "January 2012 – May 2016 ESP" section of the OPCo rate matters.

PJM/MISO Market Flow Calculation Settlement Adjustments - Affecting APCo, I&M and OPCo

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. In June 2011, the FERC approved the settlement agreement.

Modification of the Transmission Coordination Agreement (TCA) – Affecting PSO and SWEPCo

PSO, SWEPCo and TNC are parties to the TCA, originally dated January 1, 1997, as amended. The TCA provides for the allocation among the parties of revenues collected for transmission and ancillary services provided under the Open Access Transmission Tariff (OATT).

In April 2011, the FERC accepted proposed revisions to the TCA. Under this amendment, TNC was removed from the TCA. In addition, the amended TCA provides for the allocation of SPP OATT revenues between PSO and SWEPCo based on the SPP formula rate revenue requirements for transmission investment and related expenses of each company. The amended TCA was effective May 1, 2011.

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	APCo			I&M		
Regulatory Assets:	December 31, 2011	December 31, 2010	Remaining Recovery Period	December 31, 2011	December 31, 2010	Remaining Recovery Period
	(in thousands)			(in thousands)		
Current Regulatory Assets						
Under-recovered Fuel Costs - earns a return	$ 41,105	$ 18,300	1 year	$ -	$ -	
Under-recovered Fuel Costs - does not earn a return	-	-		8,876	8,467	1 year
Total Current Regulatory Assets	$ 41,105	$ 18,300		$ 8,876	$ 8,467	
Noncurrent Regulatory Assets						
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:						
Regulatory Assets Currently Not Earning a Return						
Deferred Wind Power Costs	$ 38,192	$ 28,584		$ -	$ -	
Virginia Environmental Rate Adjustment Clause	17,950	55,724		-	-	
Mountaineer Carbon Capture and Storage Product Validation Facility	14,155	59,866		-	-	
Special Rate Mechanism for Century Aluminum	12,811	12,628		-	-	
Transmission Agreement Phase-In	1,925	288		-	-	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	1,335	-		1,680	-	
Litigation Settlement	-	-		10,803	-	
Storm Related Costs	-	25,225		-	-	
Other Regulatory Assets Not Yet Being Recovered	1,010	316		-	-	
Total Regulatory Assets Not Yet Being Recovered	87,378	182,631		12,483	-	
Regulatory assets being recovered:						
Regulatory Assets Currently Earning a Return						
Expanded Net Energy Charge	326,766	361,314	2 years	-	-	
Storm Related Costs	25,225	-	7 years	-	-	
Unamortized Loss on Reacquired Debt	13,592	12,679	31 years	17,355	18,507	21 years
RTO Formation/Integration Costs	5,194	5,952	8 years	3,858	4,437	8 years
Customer Choice Implementation Costs	-	-		4,680	6,767	2 years
Other Regulatory Assets Being Recovered	-	-		-	1,103	
Regulatory Assets Currently Not Earning a Return						
Income Taxes, Net	512,025	523,009	30 years	188,749	159,453	37 years
Pension and OPEB Funded Status	362,322	335,105	13 years	291,392	268,080	13 years
Expanded Net Energy Charge	31,979	-	6 years	-	-	
Virginia Environmental Rate Adjustment Clause	23,844	-	2 years	-	-	
Postemployment Benefits	22,645	25,484	4 years	9,137	8,968	4 years
Virginia Transmission Rate Adjustment Clause	19,553	19,271	2 years	-	-	
Storm Related Costs	16,324	-	7 years	-	-	
Deferred Restructuring Costs	12,537	-	7 years	4,952	6,217	4 years
Asset Retirement Obligation	10,524	12,560	6 years	3,396	2,700	9 years
Deferred Wind Power Costs	6,284	-	2 years	-	-	
Virginia Environmental and Reliability Costs Recovery	3,838	4,421	2 years	-	-	
Cook Nuclear Plant Refueling Outage Levelization	-	-		40,551	53,795	2 years
Deferred PJM Fees	-	-		21,746	7,078	1 year
River Transportation Division Expenses	-	-		1,899	339	1 year
West Virginia Reliability Expense	-	3,158		-	-	
Off-system Sales Margin Sharing	-	-		-	13,091	
Other Regulatory Assets Being Recovered	1,163	1,041	various	2,781	5,719	various
Total Regulatory Assets Being Recovered	1,393,815	1,303,994		590,496	556,254	
Total Noncurrent Regulatory Assets	$ 1,481,193	$ 1,486,625		$ 602,979	$ 556,254	

Regulatory Liabilities:	APCo December 31, 2011	APCo December 31, 2010	APCo Remaining Refund Period	I&M December 31, 2011	I&M December 31, 2010	I&M Remaining Refund Period
	(in thousands)			(in thousands)		
Current Regulatory Liabilities						
Over-recovered Fuel Costs - pays a return	$ -	$ -		$ 25	$ 1	1 year
Total Current Regulatory Liabilities	$ -	$ -		$ 25	$ 1	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits						
Regulatory liabilities not yet being paid:						
Regulatory Liabilities Currently Paying a Return						
Other Regulatory Liabilities Not Yet Being Paid	$ -	$ -		$ 318	$ -	
Regulatory Liabilities Currently Not Paying a Return						
Other Regulatory Liabilities Not Yet Being Paid	327	-		136	147	
Total Regulatory Liabilities Not Yet Being Paid	327	-		454	147	
Regulatory liabilities being paid:						
Regulatory Liabilities Currently Paying a Return						
Asset Removal Costs	526,885	500,667	(a)	362,134	357,493	(a)
Deferred Investment Tax Credits	3,231	5,097	9 years	-	-	
Regulatory Liabilities Currently Not Paying a Return						
Deferred State Income Tax Coal Credits	28,727	28,900	10 years	-	-	
Unrealized Gain on Forward Commitments	15,597	25,799	5 years	21,785	28,045	5 years
Deferred Investment Tax Credits	1,214	1,918	9 years	52,633	55,416	75 years
Energy Efficiency/Peak Demand Reduction	811	-	1 year	11,078	1,287	1 year
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	-	-		377,162	353,689	(b)
Spent Nuclear Fuel Liability	-	-		42,603	41,932	(b)
Off-system Sales Margin Sharing	-	-		5,892	-	1 year
Indiana Clean Coal Technology Rider Liability	-	-		1,242	2,494	1 year
Over-recovery of PJM Expenses	-	-		-	11,671	
Other Regulatory Liabilities Being Paid	-	-		219	23	various
Total Regulatory Liabilities Being Paid	576,465	562,381		874,748	852,050	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 576,792	$ 562,381		$ 875,202	$ 852,197	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

	OPCo		
	December 31,		Remaining Recovery Period
Regulatory Assets:	2011	2010	
	(In thousands)		
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Economic Development Rider	$ 12,572	$ 6,114	
Customer Choice Deferrals	-	58,857	
Line Extension Carrying Costs	-	54,955	
Storm Related Costs	-	30,143	
Acquisition of Monongahela Power	-	7,929	
Other Regulatory Assets Not Yet Being Recovered	-	678	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	8,375	-	
Acquisition of Monongahela Power	-	4,052	
Other Regulatory Assets Not Yet Being Recovered	-	101	
Total Regulatory Assets Not Yet Being Recovered	20,947	162,829	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Fuel Adjustment Clause	506,607	475,835	7 years
Distribution Asset Recovery Rider	173,274	-	7 years
Transmission Cost Recovery Rider	28,404	383	2 years
Unamortized Loss on Reacquired Debt	14,552	15,889	27 years
Economic Development Rider	11,738	1,406	1 year
RTO Formation/Integration Costs	7,836	8,967	8 years
Acquisition of Monongahela Power	-	504	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	389,712	363,831	13 years
Income Taxes, Net	190,981	182,286	20 years
Unrealized Loss on Forward Commitments	9,930	5,788	1 year
Postemployment Benefits	8,669	8,806	4 years
Enhanced Service Reliability Plan	4,454	3,377	1 year
Deferred Contribution Expense	3,400	-	4 years
Energy Efficiency/Peak Demand Reduction	-	2,221	
Total Regulatory Assets Being Recovered	1,349,557	1,069,293	
Total Noncurrent Regulatory Assets	$ 1,370,504	$ 1,232,122	

	OPCo		
	December 31,		Remaining Refund Period
	2011	2010	
Regulatory Liabilities:	(in thousands)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
IGCC Preconstruction Costs	$ 4,196	$ -	
Regulatory Liabilities Currently Not Paying a Return			
Over-recovery of Costs Related to gridSMART®	-	6,182	
Low Income Customers/Economic Recovery	-	3,420	
Other Regulatory Liabilities Not Yet Being Paid	216	3,166	
Total Regulatory Liabilities Not Yet Being Paid	4,412	12,768	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	251,100	256,546	(a)
Economic Development Rider	2,428	336	1 year
Deferred Investment Tax Credits	549	1,085	8 years
Transmission Cost Recovery Rider	542	2,419	1 year
Regulatory Liabilities Currently Not Paying a Return			
Energy Efficiency/Peak Demand Reduction	19,124	2,245	3 years
Deferred Investment Tax Credits	12,944	14,787	13 years
Over-recovery of Costs Related to gridSMART®	7,504	-	2 years
Low Income Customers/Economic Recovery	2,521	-	5 years
Unrealized Gain on Forward Commitments	-	105	
Total Regulatory Liabilities Being Paid	296,712	277,523	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 301,124	$ 290,291	

(a) Relieved as removal costs are incurred.

	PSO			SWEPCo		
	December 31,		Remaining Recovery	December 31,		Remaining Recovery
	2011	2010	Period	2011	2010	Period
Regulatory Assets:	(in thousands)			(in thousands)		
Current Regulatory Assets						
Under-recovered Fuel Costs - earns a return	$ 4,313	$ 37,262	1 year	$ 10,843	$ 758	1 year
Noncurrent Regulatory Assets						
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:						
Regulatory Assets Currently Not Earning a Return						
Mountaineer Carbon Capture and Storage Commercial Scale Facility	$ -	$ -		$ 2,380	$ -	
Storm Related Costs	-	17,256		-	1,239	
Other Regulatory Assets Not Yet Being Recovered	-	574		1,699	613	
Total Regulatory Assets Not Yet Being Recovered	-	17,830		4,079	1,852	
Regulatory assets being recovered:						
Regulatory Assets Currently Earning a Return						
Storm Related Costs	38,659	38,499	2 years	965	-	2 years
Unamortized Loss on Reacquired Debt	12,538	8,277	21 years	10,768	12,422	32 years
Red Rock Generating Facility	10,180	10,406	45 years	-	-	
Acquisition of Valley Electric Membership Corporation (VEMCO)	-	-		8,789	6,500	4 years
Regulatory Assets Currently Not Earning a Return						
Pension and OPEB Funded Status	178,295	166,333	13 years	176,587	163,870	13 years
Vegetation Management	11,196	13,303	1 year	-	-	
Deferral of Major Generation Overhauls	6,133	4,083	6 years	-	-	
Energy Efficiency/Peak Demand Reduction	4,394	3,705	1 year	1,284	495	1 year
Income Taxes, Net	2,923	691	33 years	178,826	132,118	28 years
Unrealized Loss on Forward Commitments	1,706	285	2 years	4,684	2,975	2 years
Rate Case Expense	216	-	2 years	3,602	4,606	2 years
Storm Related Costs	-	-		2,556	4,800	2 years
Dolet Hills Deferred Fuel	-	-		1,886	2,725	3 years
Other Regulatory Assets Being Recovered	305	133	various	250	335	various
Total Regulatory Assets Being Recovered	266,545	245,715		390,197	330,846	
Total Noncurrent Regulatory Assets	$ 266,545	$ 263,545		$ 394,276	$ 332,698	

	PSO			SWEPCo		
	December 31,		Remaining Refund	December 31,		Remaining Refund
	2011	2010	Period	2011	2010	Period
Regulatory Liabilities:	(in thousands)			(in thousands)		
Current Regulatory Liabilities						
Over-recovered Fuel Costs - pays a return	$ -	$ -		$ 5,032	$ 16,432	1 year
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits						
Regulatory liabilities not yet being paid:						
Regulatory Liabilities Currently Paying a Return						
Refundable Construction Financing Costs	$ -	$ -		$ 52,594	$ 20,139	
Regulatory Liabilities Currently Not Paying a Return						
Over-recovery of Costs Related to gridSMART®	4,232	3,806		-	-	
Storm Related Costs	2,248	3,493		-	-	
Other Regulatory Liabilities Not Yet Being Paid	-	-		806	806	
Total Regulatory Liabilities Not Yet Being Paid	6,480	7,299		53,400	20,945	
Regulatory liabilities being paid:						
Regulatory Liabilities Currently Paying a Return						
Asset Removal Costs	280,491	284,230	(a)	353,067	346,402	(a)
Excess Earnings	-	-		3,047	3,119	42 years
Other Regulatory Liabilities Being Paid	-	-		1,305	1,667	various
Regulatory Liabilities Currently Not Paying a Return						
Deferred Investment Tax Credits	40,310	41,166	37 years	13,318	13,868	27 years
Energy Efficiency/Peak Demand Reduction	6,444	4,266	1 year	-	-	
Vegetation Management	-	-		3,158	5,672	1 year
Other Regulatory Liabilities Being Paid	1,087	-	various	1,276	2,000	various
Total Regulatory Liabilities Being Paid	328,332	329,662		375,171	372,728	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 334,812	$ 336,961		$ 428,571	$ 393,673	

(a) Relieved as removal costs are incurred.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The Registrant Subsidiaries are subject to certain claims and legal actions arising in their ordinary course of business. In addition, their business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements.

COMMITMENTS

Construction and Commitments – Affecting APCo, I&M, OPCo, PSO and SWEPCo

The Registrant Subsidiaries have substantial construction commitments to support their operations and environmental investments. In managing the overall construction program and in the normal course of business, the Registrant Subsidiaries contractually commit to third-party construction vendors for certain material purchases and other construction services. The following table shows the forecasted construction expenditures, excluding equity AFUDC and capitalized interest, by Registrant Subsidiary for 2012:

Company	Forecasted Construction Expenditures
	(in millions)
APCo	$ 449
I&M	468
OPCo	569
PSO	204
SWEPCo	475

The Registrant Subsidiaries also purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following tables summarize the Registrant Subsidiaries' actual contractual commitments at December 31, 2011:

Contractual Commitments - APCo	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 702,667	$ 884,784	$ 444,453	$ 233,099	$ 2,265,003
Energy and Capacity Purchase Contracts (b)	14,154	26,779	27,508	172,766	241,207
Construction Contracts for Capital Assets (c)	3,891	-	-	-	3,891
Total	$ 720,712	$ 911,563	$ 471,961	$ 405,865	$ 2,510,101

Contractual Commitments - I&M	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 331,673	$ 427,890	$ 276,480	$ 45,700	$ 1,081,743
Energy and Capacity Purchase Contracts (b)	1,068	612	326	-	2,006
Construction Contracts for Capital Assets (c)	1,217	-	-	-	1,217
Total	$ 333,958	$ 428,502	$ 276,806	$ 45,700	$ 1,084,966

Contractual Commitments - OPCo	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 1,210,682	$ 2,120,731	$ 1,716,511	$ 2,732,577	$ 7,780,501
Energy and Capacity Purchase Contracts (b)	12,745	6,676	6,017	35,845	61,283
Construction Contracts for Capital Assets (c)	11,509	-	-	-	11,509
Total	$ 1,234,936	$ 2,127,407	$ 1,722,528	$ 2,768,422	$ 7,853,293

Contractual Commitments - PSO		Less Than 1 year		2-3 years		4-5 years		After 5 years		Total
						(in thousands)				
Fuel Purchase Contracts (a)	$	180,454	$	137,450	$	82,450	$	41,225	$	441,579
Energy and Capacity Purchase Contracts (b)		55,550		139,468		143,326		593,040		931,384
Construction Contracts for Capital Assets (c)		1,272		-		-		-		1,272
Total	$	237,276	$	276,918	$	225,776	$	634,265	$	1,374,235

Contractual Commitments - SWEPCo		Less Than 1 year		2-3 years		4-5 years		After 5 years		Total
						(in thousands)				
Fuel Purchase Contracts (a)	$	260,709	$	269,631	$	50,567	$	54,930	$	635,837
Energy and Capacity Purchase Contracts (b)		19,349		39,169		39,946		264,706		363,170
Construction Contracts for Capital Assets (c)		10,712		-		-		-		10,712
Total	$	290,770	$	308,800	$	90,513	$	319,636	$	1,009,719

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of projects costs.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit – Affecting APCo, I&M, OPCo and SWEPCo

Certain Registrant Subsidiaries enter into standby letters of credit with third parties. These letters of credit are issued in the ordinary course of business and cover items such as insurance programs, security deposits and debt service reserves.

AEP has credit facilities totaling $3.25 billion, under which up to $1.35 billion may be issued as letters of credit. In July 2011, AEP replaced the $1.5 billion facility due in 2012 with a new $1.75 billion facility maturing in July 2016 and extended the $1.5 billion facility due in 2013 to expire in June 2015. As of December 31, 2011, the maximum future payments of the letters of credit were as follows:

Company		Amount	Maturity
		(in thousands)	
I&M	$	150	March 2012
SWEPCo		4,448	March 2012

In March 2011, the Registrant Subsidiaries and certain other companies in the AEP System terminated a $478 million credit agreement that was scheduled to mature in April 2011 and was used to support $472 million of variable rate Pollution Control Bonds. In March 2011, certain of these variable rate Pollution Control bonds were remarketed and supported by bilateral letters of credit for $361 million while others were reacquired and are being held in trust as follows:

Company		Remarketed		Reacquired and Held in Trust		Bilateral Letters of Credit	Maturity of Bilateral Letters of Credit
				(in thousands)			
APCo	$	229,650	$	-	$	232,293	March 2013 to March 2014
I&M		77,000		-		77,886	March 2013
OPCo		50,000		115,000		50,575	March 2013

Guarantees of Third-Party Obligations – Affecting SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation. In July 2011, SWEPCo's guarantee was increased from $65 million to $100 million due to expansion of the mining area. 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 Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, it is estimated the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of December 31, 2011, SWEPCo has collected approximately $54 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $22 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $30 million is recorded in Asset Retirement Obligations on SWEPCo's balance sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees – Affecting APCo, I&M, OPCo, PSO and SWEPCo

Contracts

The Registrant Subsidiaries enter into certain types of contracts which 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. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2011, there were no material liabilities recorded for any indemnifications.

APCo, I&M and OPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies related to purchase power and sale activity pursuant to the SIA. PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

Lease Obligations

Certain Registrant Subsidiaries lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 12 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims – Affecting APCo, I&M, OPCo, PSO and SWEPCo

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. In 2010, the U.S. Supreme Court granted the defendants' petition for review. In June 2011, the U.S. Supreme Court reversed and remanded the case to the Court of Appeals, finding that plaintiffs' federal common law claims are displaced by the regulatory authority granted to the Federal EPA under the CAA. After the remand, the plaintiffs asked the Second Circuit to return the case to the district court so that they could withdraw their complaints. The cases were returned to the district court and the plaintiffs' federal common law claims were dismissed in December 2011.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. Management believes the claims are without merit, and in addition to other defenses, are barred by the doctrine of collateral estoppel and the applicable statute of limitations. Management intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims – Affecting APCo, I&M, OPCo, PSO and SWEPCo

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. The court accepted supplemental briefing on the impact of the Supreme Court's decision and heard oral argument in November 2011. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation – Affecting APCo, I&M, OPCo, PSO and SWEPCo

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 treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. The Registrant Subsidiaries currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2011, APCo is named as a Potentially Responsible Party (PRP) for one site and OPCo is named a PRP for three sites by the Federal EPA. There are eight additional sites for which APCo, I&M, OPCo, and SWEPCo have received information requests which could lead to PRP designation. I&M and SWEPCo have also been named potentially liable at two sites each under state law including the I&M site discussed in the next paragraph. In those instances where the Registrant Subsidiaries have been named a PRP or defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ and recorded a provision of approximately $10 million. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. Management cannot predict the amount of additional cost, if any.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be 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. At present, management's estimates do not anticipate material cleanup costs for identified Superfund sites, except the I&M site discussed above.

Amos Plant – State and Federal Enforcement Proceedings – Affecting APCo and OPCo

In March 2010, APCo and OPCo received a letter from the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), alleging that at various times in 2007 through 2009 the units at Amos Plant reported periods of excess opacity (indicator of compliance with particulate matter emission limits) that lasted for more than 30 consecutive minutes in a 24-hour period and that certain required notifications were not made. Management met with representatives of DAQ to discuss these occurrences and the steps taken to prevent a recurrence. DAQ indicated that additional enforcement action may be taken, including imposition of a civil penalty of approximately $240 thousand. APCo and OPCo denied that violations of the reporting requirements occurred and maintain that the proper reporting was done. In March 2011, APCo and OPCo resolved these issues through the entry of a consent order that included the payment of a $75 thousand civil penalty and certain improvements in the opacity reports.

In March 2010, APCo and OPCo received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting APCo and OPCo to engage in settlement negotiations. The request includes a proposed civil penalty of approximately $300 thousand. Management provided additional information to representatives of the Federal EPA. Based on the information, the Federal EPA determined that it will not further pursue enforcement for several alleged violations and management agreed to resolve the remaining allegations through a consent order that includes payment of a $36 thousand civil penalty by APCo and OPCo.

NUCLEAR CONTINGENCIES – AFFECTING I&M

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2009. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $831 million to $1.5 billion in 2009 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was $14 million in 2011, $14 million in 2010 and $16 million in 2009. Reduced annual decommissioning cost recovery amounts reflect the units' longer estimated life and operating licenses granted by the NRC. Decommissioning costs recovered from customers are deposited in external trusts.

At December 31, 2011 and 2010, the total decommissioning trust fund balance was $1.3 billion and $1.2 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2011 and 2010, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $308 million and $307 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the Federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $14 million to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2013. The proceeds reduced capital costs for dry cask storage.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $41 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 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 $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, net income, cash flows and financial condition could be adversely affected.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1.

I&M maintains insurance through NEIL. As of December 31, 2011, I&M recorded $64 million on its balance sheet representing amounts due from NEIL under the insurance policies. Through December 31, 2011, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

I&M also maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by $78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The review by NEIL includes the timing of the unit's return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses – Affecting APCo, I&M, OPCo, PSO and SWEPCo

The Registrant Subsidiaries maintain insurance coverage normal and customary for electric utilities, subject to various deductibles. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by the Registrant Subsidiaries. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote for a discussion of I&M's nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on net income, cash flows and financial condition.

Fort Wayne Lease – Affecting I&M

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease and reached an agreement (subject to IURC approval) in 2010. The agreement required I&M to purchase the remaining leased property and settled claims Fort Wayne asserted. The agreement provided that I&M pay Fort Wayne a total of $39 million, including interest, over 15 years and Fort Wayne recognized that I&M is the exclusive electricity supplier in the Fort Wayne area. In August 2011, the IURC approved a settlement agreement with the Indiana Office of Utility Consumer Counselor. The transaction is final.

Coal Transportation Rate Dispute – Affecting PSO

In 1985, the Burlington Northern Railroad Co. (now BNSF) entered into a coal transportation agreement with PSO. The agreement contained a base rate subject to adjustment, a rate floor, a reopener provision and an arbitration provision. In 1992, PSO reopened the pricing provision. The parties failed to reach an agreement and the matter was arbitrated, with the arbitration panel establishing a lowered rate as of July 1, 1992 (the 1992 Rate) and modifying the rate adjustment formula. The decision did not mention the rate floor. From April 1996 through the contract termination in December 2001, the 1992 Rate exceeded the adjusted rate determined according to the decision. PSO paid the adjusted rate and contended that the panel eliminated the rate floor. BNSF invoiced at the 1992 Rate and contended that the 1992 Rate was the new rate floor. PSO terminated the contract by paying a termination fee, as required by the agreement. BNSF contends that the termination fee should have been calculated on the 1992 Rate, not the adjusted rate, resulting in an underpayment of approximately $9.5 million, including interest.

This matter was submitted to an arbitration board. In April 2006, the arbitration board filed its decision, denying BNSF's underpayments claim. PSO filed a request for an order confirming the arbitration award and a request for entry of judgment on the award with the U.S. District Court for the Northern District of Oklahoma. On July 14, 2006, the U.S. District Court issued an order confirming the arbitration award. BNSF pursued the matter by filing a Motion to Reconsider, which was granted, but in August 2009, the U.S. District Court upheld the arbitration board's decision. BNSF further pursued the decision by appealing to the U.S. Court of Appeals, where in December 2010, the Tenth Circuit Court of Appeals affirmed the U.S. District Court's order confirming the arbitration award. PSO then sought and received approval for reimbursement for attorneys' fees and expenses related to the proceedings at the district court and appellate courts. This matter is resolved.

6. ACQUISITIONS AND IMPAIRMENTS

2011

Dresden Plant - Affecting APCo

In August 2011, APCo purchased the partially completed Dresden Plant from AEGCo, at cost, for $302 million. The Dresden Plant was completed and placed in service in January 2012. The Dresden Plant is located near Dresden, Ohio and is a natural gas, combined cycle power plant with a generating capacity of 580 MW.

2010

Valley Electric Membership Corporation – Affecting SWEPCo

In October 2010, SWEPCo purchased certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO) for approximately $102 million and began serving VEMCO's 30,000 customers in Louisiana.

<u>2009</u>

Oxbow Lignite Company and Red River Mining Company – Affecting SWEPCo

In December 2009, SWEPCo purchased 50% of the Oxbow Lignite Company, LLC (OLC) membership interest for $13 million. CLECO acquired the remaining 50% membership interest in the OLC for $13 million. The Oxbow Mine is located near Coushatta, Louisiana and is used as one of the fuel sources for SWEPCo's and CLECO's jointly-owned Dolet Hills Generating Station. SWEPCo accounts for OLC as an equity investment. Also, in December 2009, DHLC purchased mining equipment and assets for $16 million from the Red River Mining Company.

IMPAIRMENTS

<u>2011</u>

Turk Plant (Utility Operations segment) – Affecting SWEPCo

In the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statements of income related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Muskingum River Plant Unit 5 FGD Project (MR5) – Affecting OPCo

In September 2011, subsequent to the stipulation agreement filed with the PUCO, management determined that OPCo was not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statements of income.

Sporn Plant Unit 5 – Affecting OPCo

In the third quarter of 2011, management decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the AEP Power Pool. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statements of income.

7. <u>BENEFIT PLANS</u>

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

The Registrant Subsidiaries participate in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. The Registrant Subsidiaries also participate in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

Due to the Registrant Subsidiaries' participation in AEP's benefits plans, the assumptions used by the actuary and the accounting for the plans by each subsidiary are the same. This section details the assumptions that apply to all Registrant Subsidiaries and the rate of compensation increase for each subsidiary.

The Registrant Subsidiaries recognize the funded status associated with defined benefit pension and OPEB plans in their balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. The Registrant Subsidiaries recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrant Subsidiaries record a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of the Registrant Subsidiaries' benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
Assumption	**2011**	**2010**	**2011**	**2010**
Discount Rate	4.55 %	5.05 %	4.75 %	5.25 %

	Pension Plans	
Assumption - Rate of Compensation Increase (a)	**2011**	**2010**
APCo	4.65 %	4.70 %
I&M	4.90 %	4.90 %
OPCo	4.95 %	5.05 %
PSO	4.85 %	4.95 %
SWEPCo	4.70 %	4.80 %

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate is the same for each Registrant Subsidiary.

For 2011, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrant Subsidiary's population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of each Registrant Subsidiary's benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
Assumptions	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
Discount Rate	5.05 %	5.60 %	6.00 %	5.25 %	5.85 %	6.10 %
Expected Return on Plan Assets	7.75 %	8.00 %	8.00 %	7.50 %	8.00 %	7.75 %

	Pension Plans		
Assumption - Rate of Compensation Increase	**2011**	**2010**	**2009**
APCo	4.65 %	4.35 %	5.65 %
I&M	4.90 %	4.55 %	5.85 %
OPCo	4.95 %	4.70 %	6.00 %
PSO	4.85 %	4.60 %	5.90 %
SWEPCo	4.70 %	4.45 %	5.75 %

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth. The expected return on plan assets is the same for each Registrant Subsidiary.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2011	2010
Initial	7.50 %	8.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	2016

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:

	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost:					
1% Increase	$ 3,806	$ 2,972	$ 5,188	$ 1,300	$ 1,500
1% Decrease	(3,015)	(2,367)	(4,110)	(1,036)	(1,195)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation:					
1% Increase	$ 50,216	$ 33,657	$ 65,251	$ 15,088	$ 17,499
1% Decrease	(40,748)	(27,448)	(53,015)	(12,314)	(14,281)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. At December 31, 2011, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2011 and 2010

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 652,219	$ 632,832	$ 383,152	$ 348,787
Service Cost	7,199	12,908	4,983	5,722
Interest Cost	32,293	33,956	19,468	20,300
Actuarial Loss	29,137	28,909	41,306	33,656
Plan Amendment Prior Service Credit	-	-	(31,145)	(4,257)
Benefit Payments	(39,398)	(56,386)	(30,040)	(27,677)
Participant Contributions	-	-	6,005	4,782
Medicare Subsidy	-	-	1,753	1,839
Benefit Obligation at December 31	$ 681,450	$ 652,219	$ 395,482	$ 383,152
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 512,836	$ 474,657	$ 243,771	$ 217,160
Actual Gain (Loss) on Plan Assets	36,970	57,745	(4,102)	29,112
Company Contributions	60,348	36,820	14,101	20,394
Participant Contributions	-	-	6,005	4,782
Benefit Payments	(39,398)	(56,386)	(30,040)	(27,677)
Fair Value of Plan Assets at December 31	$ 570,756	$ 512,836	$ 229,735	$ 243,771
Underfunded Status at December 31	$ (110,694)	$ (139,383)	$ (165,747)	$ (139,381)

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 560,982	$ 526,363	$ 266,742	$ 241,847
Service Cost	9,447	15,284	6,119	6,750
Interest Cost	27,726	29,085	13,610	14,164
Actuarial Loss	17,289	40,694	28,876	20,980
Plan Amendment Prior Service Credit	-	-	(24,846)	(4,273)
Benefit Payments	(33,767)	(50,444)	(18,387)	(17,439)
Participant Contributions	-	-	4,112	3,526
Medicare Subsidy	-	-	1,127	1,187
Benefit Obligation at December 31	$ 581,677	$ 560,982	$ 277,353	$ 266,742
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 451,688	$ 379,562	$ 188,690	$ 166,682
Actual Gain (Loss) on Plan Assets	32,773	50,811	(3,946)	20,983
Company Contributions	53,232	71,759	10,768	14,938
Participant Contributions	-	-	4,112	3,526
Benefit Payments	(33,767)	(50,444)	(18,387)	(17,439)
Fair Value of Plan Assets at December 31	$ 503,926	$ 451,688	$ 181,237	$ 188,690
Underfunded Status at December 31	$ (77,751)	$ (109,294)	$ (96,116)	$ (78,052)

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 984,089	$ 981,481	$ 506,255	$ 457,872
Service Cost	10,230	17,254	7,827	8,187
Interest Cost	48,350	51,900	25,497	26,498
Actuarial Loss	42,693	31,409	49,132	45,633
Plan Amendment Prior Service Credit	-	-	(42,357)	(6,039)
Curtailment	-	-	605	-
Benefit Payments	(64,472)	(97,955)	(38,347)	(35,673)
Participant Contributions	-	-	8,828	7,253
Medicare Subsidy	-	-	2,452	2,524
Benefit Obligation at December 31	$ 1,020,890	$ 984,089	$ 519,892	$ 506,255
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 799,281	$ 756,768	$ 333,198	$ 299,551
Actual Gain (Loss) on Plan Assets	63,181	81,765	(6,589)	38,466
Company Contributions	127,949	58,703	14,746	23,601
Participant Contributions	-	-	8,828	7,253
Benefit Payments	(64,472)	(97,955)	(38,347)	(35,673)
Fair Value of Plan Assets at December 31	$ 925,939	$ 799,281	$ 311,836	$ 333,198
Underfunded Status at December 31	$ (94,951)	$ (184,808)	$ (208,056)	$ (173,057)

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 268,180	$ 285,592	$ 116,935	$ 108,220
Service Cost	5,760	6,052	2,621	2,815
Interest Cost	13,285	14,888	6,046	6,360
Actuarial (Gain) Loss	7,679	(1,047)	16,705	7,540
Plan Amendment Prior Service Credit	-	-	(11,612)	(2,408)
Benefit Payments	(17,456)	(37,305)	(8,110)	(8,049)
Participant Contributions	-	-	1,926	1,763
Medicare Subsidy	-	-	653	694
Benefit Obligation at December 31	$ 277,448	$ 268,180	$ 125,164	$ 116,935
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 213,576	$ 216,966	$ 83,917	$ 75,700
Actual Gain on Plan Assets	16,430	21,040	646	6,357
Company Contributions	33,219	12,875	4,711	8,146
Participant Contributions	-	-	1,926	1,763
Benefit Payments	(17,456)	(37,305)	(8,110)	(8,049)
Fair Value of Plan Assets at December 31	$ 245,769	$ 213,576	$ 83,090	$ 83,917
Underfunded Status at December 31	$ (31,679)	$ (54,604)	$ (42,074)	$ (33,018)

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	2011	2010	2011	2010
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 267,206	$ 288,081	$ 129,726	$ 118,571
Service Cost	6,573	7,046	3,029	3,108
Interest Cost	13,331	15,093	6,969	6,940
Actuarial (Gain) Loss	7,861	(2,014)	24,547	9,084
Plan Amendment Prior Service Credit	-	-	(13,534)	(2,399)
Benefit Payments	(17,377)	(41,000)	(8,226)	(8,125)
Participant Contributions	-	-	2,041	1,907
Medicare Subsidy	-	-	608	640
Benefit Obligation at December 31	$ 277,594	$ 267,206	$ 145,160	$ 129,726
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 224,618	$ 212,626	$ 93,097	$ 82,940
Actual Gain on Plan Assets	17,283	23,854	3,797	8,150
Company Contributions	31,337	29,138	5,655	8,225
Participant Contributions	-	-	2,041	1,907
Benefit Payments	(17,377)	(41,000)	(8,226)	(8,125)
Fair Value of Plan Assets at December 31	$ 255,861	$ 224,618	$ 96,364	$ 93,097
Underfunded Status at December 31	$ (21,733)	$ (42,588)	$ (48,796)	$ (36,629)

Amounts Recognized on the Registrant Subsidiaries' Balance Sheets as of December 31, 2011 and 2010

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
APCo	2011	2010	2011	2010
	(in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (34)	$ (34)	$ (2,956)	$ (2,854)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(110,660)	(139,349)	(162,791)	(136,527)
Underfunded Status	$ (110,694)	$ (139,383)	$ (165,747)	$ (139,381)

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
I&M	2011	2010	2011	2010
	(in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (14)	$ (57)	$ (308)	$ (313)
Deferred Credits and Other Noncurrent Liabilities Accrued Long-term Benefit Liability	(77,737)	(109,237)	(95,808)	(77,739)
Underfunded Status	$ (77,751)	$ (109,294)	$ (96,116)	$ (78,052)

OPCo	Pension Plans 2011	Pension Plans 2010	Other Postretirement Benefit Plans 2011	Other Postretirement Benefit Plans 2010
	December 31, (in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (62)	$ (59)	$ (991)	$ (667)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(94,889)	(184,749)	(207,065)	(172,390)
Underfunded Status	$ (94,951)	$ (184,808)	$ (208,056)	$ (173,057)

PSO	Pension Plans 2011	Pension Plans 2010	Other Postretirement Benefit Plans 2011	Other Postretirement Benefit Plans 2010
	December 31, (in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (88)	$ (68)	$ -	$ -
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(31,591)	(54,536)	(42,074)	(33,018)
Underfunded Status	$ (31,679)	$ (54,604)	$ (42,074)	$ (33,018)

SWEPCo	Pension Plans 2011	Pension Plans 2010	Other Postretirement Benefit Plans 2011	Other Postretirement Benefit Plans 2010
	December 31, (in thousands)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (78)	$ (73)	$ -	$ -
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(21,655)	(42,515)	(48,796)	(36,629)
Underfunded Status	$ (21,733)	$ (42,588)	$ (48,796)	$ (36,629)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2011 and 2010

APCo	Pension Plans 2011	Pension Plans 2010	Other Postretirement Benefit Plans 2011	Other Postretirement Benefit Plans 2010
Components	December 31, (in thousands)			
Net Actuarial Loss	$ 308,223	$ 290,798	$ 174,615	$ 115,350
Prior Service Cost (Credit)	1,393	2,310	(33,060)	(2,086)
Transition Obligation	-	-	780	1,947
Recorded as				
Regulatory Assets	$ 305,558	$ 289,214	$ 56,764	$ 45,891
Deferred Income Taxes	1,420	1,366	29,951	23,881
Net of Tax AOCI	2,638	2,528	55,620	45,439

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
Components	(in thousands)			
Net Actuarial Loss	$ 216,107	$ 208,879	$ 121,238	$ 78,483
Prior Service Cost (Credit)	1,307	2,051	(27,491)	(2,882)
Transition Obligation	-	-	132	320
Recorded as				
Regulatory Assets	$ 207,237	$ 199,982	$ 84,155	$ 68,098
Deferred Income Taxes	3,561	3,830	3,403	2,737
Net of Tax AOCI	6,616	7,118	6,321	5,086

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
Components	(in thousands)			
Net Actuarial Loss	$ 517,180	$ 497,032	$ 231,189	$ 158,876
Prior Service Cost (Credit)	2,025	3,499	(44,742)	(2,597)
Transition Obligation	-	-	104	254
Recorded as				
Regulatory Assets	$ 305,240	$ 292,702	$ 84,472	$ 71,129
Deferred Income Taxes	74,888	72,741	35,728	29,888
Net of Tax AOCI	139,077	135,088	66,351	55,516

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
Components	(in thousands)			
Net Actuarial Loss	$ 136,056	$ 134,101	$ 54,516	$ 33,922
Prior Service Cost (Credit)	181	(769)	(12,458)	(921)
Recorded as				
Regulatory Assets	$ 136,237	$ 133,332	$ 42,058	$ 33,001

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2011	2010	2011	2010
Components	(in thousands)			
Net Actuarial Loss	$ 133,542	$ 131,343	$ 59,541	$ 37,707
Prior Service Cost (Credit)	560	(235)	(10,762)	(1,095)
Recorded as				
Regulatory Assets	$ 134,102	$ 131,108	$ 31,407	$ 23,842
Deferred Income Taxes	-	-	6,081	4,469
Net of Tax AOCI	-	-	11,291	8,301

Components of the change in amounts included in AOCI and Regulatory Assets by Registrant Subsidiary during the years ended December 31, 2011 and 2010 are as follows:

Pension Plans - Components	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Actuarial Loss During the Year	$ 33,995	$ 21,372	$ 44,976	$ 8,712	$ 8,958
Amortization of Actuarial Loss	(16,570)	(14,144)	(24,828)	(6,757)	(6,759)
Amortization of Prior Service Cost (Credit)	(917)	(744)	(1,474)	950	795
Change for the Year Ended December 31, 2011	$ 16,508	$ 6,484	$ 18,674	$ 2,905	$ 2,994

Pension Plans - Components	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Actuarial Loss (Gain) During the Year	$ 14,769	$ 24,732	$ 26,308	$ (2,346)	$ (6,379)
Amortization of Actuarial Loss	(11,842)	(10,065)	(18,150)	(5,188)	(5,242)
Amortization of Prior Service Cost (Credit)	(917)	(744)	(1,474)	950	796
Change for the Year Ended December 31, 2010	$ 2,010	$ 13,923	$ 6,684	$ (6,584)	$ (10,825)

Other Postretirement Benefit Plans - Components	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Actuarial Loss During the Year	$ 65,104	$ 46,321	$ 79,611	$ 22,147	$ 23,619
Amortization of Actuarial Loss	(5,839)	(3,566)	(7,298)	(1,553)	(1,785)
Prior Service Credit	(31,145)	(24,846)	(42,357)	(11,612)	(9,409)
Amortization of Prior Service Cost (Credit)	171	237	212	75	(258)
Amortization of Transition Obligation	(1,167)	(188)	(150)	-	-
Change for the Year Ended December 31, 2011	$ 27,124	$ 17,958	$ 30,018	$ 9,057	$ 12,167

Other Postretirement Benefit Plans - Components	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Actuarial Loss During the Year	$ 23,876	$ 13,372	$ 31,207	$ 7,283	$ 7,570
Amortization of Actuarial Loss	(5,410)	(3,526)	(6,877)	(1,573)	(1,711)
Prior Service Credit	(4,257)	(4,273)	(6,039)	(2,408)	(2,399)
Amortization of Transition Obligation	(5,244)	(2,814)	(6,642)	(2,805)	(2,461)
Change for the Year Ended December 31, 2010	$ 8,965	$ 2,759	$ 11,649	$ 497	$ 999

Pension and Other Postretirement Plans' Assets

The following tables present the classification of pension plan assets within the fair value hierarchy by Registrant Subsidiary at December 31, 2011:

APCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 192,957	$ -	$ -	$ -	$ 192,957	33.8 %
International	52,904	-	-	-	52,904	9.3 %
Real Estate Investment Trusts	13,794	-	-	-	13,794	2.4 %
Common Collective Trust - International	-	17,038	-	-	17,038	3.0 %
Subtotal - Equities	259,655	17,038	-	-	276,693	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	3,483	-	-	3,483	0.6 %
United States Government and Agency Securities	-	75,042	-	-	75,042	13.2 %
Corporate Debt	-	130,606	846	-	131,452	23.0 %
Foreign Debt	-	25,289	-	-	25,289	4.4 %
State and Local Government	-	6,374	-	-	6,374	1.1 %
Other - Asset Backed	-	3,449	-	-	3,449	0.6 %
Subtotal - Fixed Income	-	244,243	846	-	245,089	42.9 %
Real Estate	-	-	21,666	-	21,666	3.8 %
Alternative Investments	-	-	21,269	-	21,269	3.7 %
Securities Lending	-	28,488	-	-	28,488	5.0 %
Securities Lending Collateral (a)	-	-	-	(31,276)	(31,276)	(5.5)%
Cash and Cash Equivalents	-	12,306	-	-	12,306	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(3,479)	(3,479)	(0.6)%
Total	$ 259,655	$ 302,075	$ 43,781	$ (34,755)	$ 570,756	100.0 %

I&M

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 170,364	$ -	$ -	$ -	$ 170,364	33.8 %
International	46,709	-	-	-	46,709	9.3 %
Real Estate Investment Trusts	12,179	-	-	-	12,179	2.4 %
Common Collective Trust - International	-	15,043	-	-	15,043	3.0 %
Subtotal - Equities	229,252	15,043	-	-	244,295	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	3,075	-	-	3,075	0.6 %
United States Government and Agency Securities	-	66,255	-	-	66,255	13.2 %
Corporate Debt	-	115,313	747	-	116,060	23.0 %
Foreign Debt	-	22,328	-	-	22,328	4.4 %
State and Local Government	-	5,628	-	-	5,628	1.1 %
Other - Asset Backed	-	3,045	-	-	3,045	0.6 %
Subtotal - Fixed Income	-	215,644	747	-	216,391	42.9 %
Real Estate	-	-	19,129	-	19,129	3.8 %
Alternative Investments	-	-	18,779	-	18,779	3.7 %
Securities Lending	-	25,153	-	-	25,153	5.0 %
Securities Lending Collateral (a)	-	-	-	(27,614)	(27,614)	(5.5)%
Cash and Cash Equivalents	-	10,865	-	-	10,865	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(3,072)	(3,072)	(0.6)%
Total	$ 229,252	$ 266,705	$ 38,655	$ (30,686)	$ 503,926	100.0 %

OPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 313,034	$ -	$ -	$ -	$ 313,034	33.8 %
International	85,825	-	-	-	85,825	9.3 %
Real Estate Investment Trusts	22,379	-	-	-	22,379	2.4 %
Common Collective Trust - International	-	27,641	-	-	27,641	3.0 %
Subtotal - Equities	421,238	27,641	-	-	448,879	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	5,650	-	-	5,650	0.6 %
United States Government and Agency Securities	-	121,741	-	-	121,741	13.2 %
Corporate Debt	-	211,883	1,372	-	213,255	23.0 %
Foreign Debt	-	41,027	-	-	41,027	4.4 %
State and Local Government	-	10,341	-	-	10,341	1.1 %
Other - Asset Backed	-	5,595	-	-	5,595	0.6 %
Subtotal - Fixed Income	-	396,237	1,372	-	397,609	42.9 %
Real Estate	-	-	35,148	-	35,148	3.8 %
Alternative Investments	-	-	34,505	-	34,505	3.7 %
Securities Lending	-	46,217	-	-	46,217	5.0 %
Securities Lending Collateral (a)	-	-	-	(50,739)	(50,739)	(5.5)%
Cash and Cash Equivalents	-	19,964	-	-	19,964	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(5,644)	(5,644)	(0.6)%
Total	$ 421,238	$ 490,059	$ 71,025	$ (56,383)	$ 925,939	100.0 %

PSO

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 83,086	$ -	$ -	$ -	$ 83,086	33.8 %
International	22,781	-	-	-	22,781	9.3 %
Real Estate Investment Trusts	5,940	-	-	-	5,940	2.4 %
Common Collective Trust - International	-	7,337	-	-	7,337	3.0 %
Subtotal - Equities	111,807	7,337	-	-	119,144	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	1,500	-	-	1,500	0.6 %
United States Government and Agency Securities	-	32,313	-	-	32,313	13.2 %
Corporate Debt	-	56,239	364	-	56,603	23.0 %
Foreign Debt	-	10,890	-	-	10,890	4.4 %
State and Local Government	-	2,745	-	-	2,745	1.1 %
Other - Asset Backed	-	1,485	-	-	1,485	0.6 %
Subtotal - Fixed Income	-	105,172	364	-	105,536	42.9 %
Real Estate	-	-	9,329	-	9,329	3.8 %
Alternative Investments	-	-	9,159	-	9,159	3.7 %
Securities Lending	-	12,267	-	-	12,267	5.0 %
Securities Lending Collateral (a)	-	-	-	(13,467)	(13,467)	(5.5)%
Cash and Cash Equivalents	-	5,299	-	-	5,299	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(1,498)	(1,498)	(0.6)%
Total	$ 111,807	$ 130,075	$ 18,852	$ (14,965)	$ 245,769	100.0 %

SWEPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 86,499	$ -	$ -	$ -	$ 86,499	33.8 %
International	23,716	-	-	-	23,716	9.3 %
Real Estate Investment Trusts	6,184	-	-	-	6,184	2.4 %
Common Collective Trust - International	-	7,638	-	-	7,638	3.0 %
Subtotal - Equities	116,399	7,638	-	-	124,037	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	1,561	-	-	1,561	0.6 %
United States Government and Agency Securities	-	33,640	-	-	33,640	13.2 %
Corporate Debt	-	58,549	379	-	58,928	23.0 %
Foreign Debt	-	11,337	-	-	11,337	4.4 %
State and Local Government	-	2,857	-	-	2,857	1.1 %
Other - Asset Backed	-	1,546	-	-	1,546	0.6 %
Subtotal - Fixed Income	-	109,490	379	-	109,869	42.9 %
Real Estate	-	-	9,712	-	9,712	3.8 %
Alternative Investments	-	-	9,535	-	9,535	3.7 %
Securities Lending	-	12,771	-	-	12,771	5.0 %
Securities Lending Collateral (a)	-	-	-	(14,020)	(14,020)	(5.5)%
Cash and Cash Equivalents	-	5,517	-	-	5,517	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(1,560)	(1,560)	(0.6)%
Total	$ 116,399	$ 135,416	$ 19,626	$ (15,580)	$ 255,861	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following tables set forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy by Registrant Subsidiary for pension assets:

APCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 11,060	$ 17,281	$ 28,341
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	2,952	1,142	4,094
Relating to Assets Sold During the Period	-	-	392	392
Purchases and Sales	-	7,654	2,454	10,108
Transfers into Level 3	846	-	-	846
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 846	$ 21,666	$ 21,269	$ 43,781

I&M	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 9,742	$ 15,220	$ 24,962
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	2,612	1,019	3,631
Relating to Assets Sold During the Period	-	-	350	350
Purchases and Sales	-	6,775	2,190	8,965
Transfers into Level 3	747	-	-	747
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 747	$ 19,129	$ 18,779	$ 38,655

OPCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 17,239	$ 26,933	$ 44,172
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	4,985	2,167	7,152
Relating to Assets Sold During the Period	-	-	744	744
Purchases and Sales	-	12,924	4,661	17,585
Transfers into Level 3	1,372	-	-	1,372
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 1,372	$ 35,148	$ 34,505	$ 71,025

PSO	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 4,606	$ 7,197	$ 11,803
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,314	561	1,875
Relating to Assets Sold During the Period	-	-	193	193
Purchases and Sales	-	3,409	1,208	4,617
Transfers into Level 3	364	-	-	364
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 364	$ 9,329	$ 9,159	$ 18,852

SWEPCo	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 4,844	$ 7,569	$ 12,413
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,355	563	1,918
Relating to Assets Sold During the Period	-	-	194	194
Purchases and Sales	-	3,513	1,209	4,722
Transfers into Level 3	379	-	-	379
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 379	$ 9,712	$ 9,535	$ 19,626

The following tables present the classification of OPEB plan assets within the fair value hierarchy by Registrant Subsidiary at December 31, 2011:

APCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 56,670	$ -	$ -	$ -	$ 56,670	24.7 %
International	61,982	-	-	-	61,982	27.0 %
Common Collective Trust - Global	-	16,159	-	-	16,159	7.0 %
Subtotal - Equities	118,652	16,159	-	-	134,811	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	11,279	-	-	11,279	4.9 %
United States Government and Agency Securities	-	13,165	-	-	13,165	5.7 %
Corporate Debt	-	24,792	-	-	24,792	10.8 %
Foreign Debt	-	5,256	-	-	5,256	2.3 %
State and Local Government	-	1,371	-	-	1,371	0.6 %
Other - Asset Backed	-	312	-	-	312	0.1 %
Subtotal - Fixed Income	-	56,175	-	-	56,175	24.4 %
Trust Owned Life Insurance:						
International Equities	-	7,533	-	-	7,533	3.3 %
United States Bonds	-	25,719	-	-	25,719	11.2 %
Cash and Cash Equivalents	2,739	3,816	-	-	6,555	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(1,058)	(1,058)	(0.5)%
Total	$ 121,391	$ 109,402	$ -	$ (1,058)	$ 229,735	100.0 %

I&M

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 44,707	$ -	$ -	$ -	$ 44,707	24.7 %
International	48,897	-	-	-	48,897	27.0 %
Common Collective Trust - Global	-	12,748	-	-	12,748	7.0 %
Subtotal - Equities	93,604	12,748	-	-	106,352	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	8,898	-	-	8,898	4.9 %
United States Government and Agency Securities	-	10,386	-	-	10,386	5.7 %
Corporate Debt	-	19,558	-	-	19,558	10.8 %
Foreign Debt	-	4,146	-	-	4,146	2.3 %
State and Local Government	-	1,082	-	-	1,082	0.6 %
Other - Asset Backed	-	246	-	-	246	0.1 %
Subtotal - Fixed Income	-	44,316	-	-	44,316	24.4 %
Trust Owned Life Insurance:						
International Equities	-	5,943	-	-	5,943	3.3 %
United States Bonds	-	20,290	-	-	20,290	11.2 %
Cash and Cash Equivalents	2,161	3,010	-	-	5,171	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(835)	(835)	(0.5)%
Total	$ 95,765	$ 86,307	$ -	$ (835)	$ 181,237	100.0 %

OPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 76,921	$ -	$ -	$ -	$ 76,921	24.7 %
International	84,133	-	-	-	84,133	27.0 %
Common Collective Trust - Global	-	21,934	-	-	21,934	7.0 %
Subtotal Equities	161,054	21,934	-	-	182,988	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	15,310	-	-	15,310	4.9 %
United States Government and Agency Securities	-	17,870	-	-	17,870	5.7 %
Corporate Debt	-	33,652	-	-	33,652	10.8 %
Foreign Debt	-	7,134	-	-	7,134	2.3 %
State and Local Government	-	1,861	-	-	1,861	0.6 %
Other - Asset Backed	-	424	-	-	424	0.1 %
Subtotal Fixed Income	-	76,251	-	-	76,251	24.4 %
Trust Owned Life Insurance:						
International Equities	-	10,225	-	-	10,225	3.3 %
United States Bonds	-	34,910	-	-	34,910	11.2 %
Cash and Cash Equivalents	3,718	5,180	-	-	8,898	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(1,436)	(1,436)	(0.5)%
Total	$ 164,772	$ 148,500	$ -	$ (1,436)	$ 311,836	100.0 %

PSO

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 20,497	$ -	$ -	$ -	$ 20,497	24.7 %
International	22,417	-	-	-	22,417	27.0 %
Common Collective Trust - Global	-	5,844	-	-	5,844	7.0 %
Subtotal - Equities	42,914	5,844	-	-	48,758	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	4,079	-	-	4,079	4.9 %
United States Government and Agency Securities	-	4,762	-	-	4,762	5.7 %
Corporate Debt	-	8,967	-	-	8,967	10.8 %
Foreign Debt	-	1,901	-	-	1,901	2.3 %
State and Local Government	-	496	-	-	496	0.6 %
Other - Asset Backed	-	113	-	-	113	0.1 %
Subtotal - Fixed Income	-	20,318	-	-	20,318	24.4 %
Trust Owned Life Insurance:						
International Equities	-	2,724	-	-	2,724	3.3 %
United States Bonds	-	9,302	-	-	9,302	11.2 %
Cash and Cash Equivalents	991	1,380	-	-	2,371	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(383)	(383)	(0.5)%
Total	$ 43,905	$ 39,568	$ -	$ (383)	$ 83,090	100.0 %

SWEPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 23,770	$ -	$ -	$ -	$ 23,770	24.7 %
International	25,999	-	-	-	25,999	27.0 %
Common Collective Trust - Global	-	6,778	-	-	6,778	7.0 %
Subtotal - Equities	49,769	6,778	-	-	56,547	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	4,731	-	-	4,731	4.9 %
United States Government and Agency Securities	-	5,522	-	-	5,522	5.7 %
Corporate Debt	-	10,399	-	-	10,399	10.8 %
Foreign Debt	-	2,205	-	-	2,205	2.3 %
State and Local Government	-	575	-	-	575	0.6 %
Other - Asset Backed	-	131	-	-	131	0.1 %
Subtotal - Fixed Income	-	23,563	-	-	23,563	24.4 %
Trust Owned Life Insurance:						
International Equities	-	3,160	-	-	3,160	3.3 %
United States Bonds	-	10,788	-	-	10,788	11.2 %
Cash and Cash Equivalents	1,149	1,601	-	-	2,750	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(444)	(444)	(0.5)%
Total	$ 50,918	$ 45,890	$ -	$ (444)	$ 96,364	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following tables present the classification of pension plan assets within the fair value hierarchy by Registrant Subsidiary at December 31, 2010:

APCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 179,421	$ 366	$ -	$ -	$ 179,787	35.1 %
International	53,559	-	-	-	53,559	10.4 %
Real Estate Investment Trusts	14,932	-	-	-	14,932	2.9 %
Common Collective Trust - International	-	21,619	-	-	21,619	4.2 %
Subtotal - Equities	247,912	21,985	-	-	269,897	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	84,280	-	-	84,280	16.4 %
Corporate Debt	-	89,296	-	-	89,296	17.4 %
Foreign Debt	-	16,900	-	-	16,900	3.3 %
State and Local Government	-	3,021	-	-	3,021	0.6 %
Other - Asset Backed	-	6,798	-	-	6,798	1.3 %
Subtotal - Fixed Income	-	200,295	-	-	200,295	39.0 %
Real Estate	-	-	11,060	-	11,060	2.2 %
Alternative Investments	-	-	17,281	-	17,281	3.4 %
Securities Lending	-	33,804	-	-	33,804	6.6 %
Securities Lending Collateral (a)	-	-	-	(36,664)	(36,664)	(7.1)%
Cash and Cash Equivalents (b)	-	16,870	-	212	17,082	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	81	81	- %
Total	$ 247,912	$ 272,954	$ 28,341	$ (36,371)	$ 512,836	100.0 %

I&M

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 158,027	$ 323	$ -	$ -	$ 158,350	35.1 %
International	47,173	-	-	-	47,173	10.4 %
Real Estate Investment Trusts	13,152	-	-	-	13,152	2.9 %
Common Collective Trust - International	-	19,041	-	-	19,041	4.2 %
Subtotal - Equities	218,352	19,364	-	-	237,716	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	74,231	-	-	74,231	16.4 %
Corporate Debt	-	78,649	-	-	78,649	17.4 %
Foreign Debt	-	14,885	-	-	14,885	3.3 %
State and Local Government	-	2,661	-	-	2,661	0.6 %
Other - Asset Backed	-	5,987	-	-	5,987	1.3 %
Subtotal - Fixed Income	-	176,413	-	-	176,413	39.0 %
Real Estate	-	-	9,742	-	9,742	2.2 %
Alternative Investments	-	-	15,220	-	15,220	3.4 %
Securities Lending	-	29,773	-	-	29,773	6.6 %
Securities Lending Collateral (a)	-	-	-	(32,292)	(32,292)	(7.1)%
Cash and Cash Equivalents (b)	-	14,859	-	186	15,045	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	71	71	- %
Total	$ 218,352	$ 240,409	$ 24,962	$ (32,035)	$ 451,688	100.0 %

OPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 279,635	$ 571	$ -	$ -	$ 280,206	35.1 %
International	83,473	-	-	-	83,473	10.4 %
Real Estate Investment Trusts	23,273	-	-	-	23,273	2.9 %
Common Collective Trust - International	-	33,695	-	-	33,695	4.2 %
Subtotal - Equities	386,381	34,266	-	-	420,647	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	131,355	-	-	131,355	16.4 %
Corporate Debt	-	139,172	-	-	139,172	17.4 %
Foreign Debt	-	26,340	-	-	26,340	3.3 %
State and Local Government	-	4,708	-	-	4,708	0.6 %
Other - Asset Backed	-	10,594	-	-	10,594	1.3 %
Subtotal - Fixed Income	-	312,169	-	-	312,169	39.0 %
Real Estate	-	-	17,239	-	17,239	2.2 %
Alternative Investments	-	-	26,933	-	26,933	3.4 %
Securities Lending	-	52,686	-	-	52,686	6.6 %
Securities Lending Collateral (a)	-	-	-	(57,142)	(57,142)	(7.1)%
Cash and Cash Equivalents (b)	-	26,293	-	330	26,623	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	126	126	- %
Total	$ 386,381	$ 425,414	$ 44,172	$ (56,686)	$ 799,281	100.0 %

PSO

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 74,721	$ 153	$ -	$ -	$ 74,874	35.1 %
International	22,305	-	-	-	22,305	10.4 %
Real Estate Investment Trusts	6,219	-	-	-	6,219	2.9 %
Common Collective Trust - International	-	9,004	-	-	9,004	4.2 %
Subtotal - Equities	103,245	9,157	-	-	112,402	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	35,099	-	-	35,099	16.4 %
Corporate Debt	-	37,188	-	-	37,188	17.4 %
Foreign Debt	-	7,038	-	-	7,038	3.3 %
State and Local Government	-	1,258	-	-	1,258	0.6 %
Other - Asset Backed	-	2,831	-	-	2,831	1.3 %
Subtotal - Fixed Income	-	83,414	-	-	83,414	39.0 %
Real Estate	-	-	4,606	-	4,606	2.2 %
Alternative Investments	-	-	7,197	-	7,197	3.4 %
Securities Lending	-	14,078	-	-	14,078	6.6 %
Securities Lending Collateral (a)	-	-	-	(15,269)	(15,269)	(7.1)%
Cash and Cash Equivalents (b)	-	7,026	-	88	7,114	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	34	34	- %
Total	$ 103,245	$ 113,675	$ 11,803	$ (15,147)	$ 213,576	100.0 %

SWEPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 78,585	$ 160	$ -	$ -	$ 78,745	35.1 %
International	23,458	-	-	-	23,458	10.4 %
Real Estate Investment Trusts	6,540	-	-	-	6,540	2.9 %
Common Collective Trust - International	-	9,469	-	-	9,469	4.2 %
Subtotal - Equities	108,583	9,629	-	-	118,212	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	36,914	-	-	36,914	16.4 %
Corporate Debt	-	39,111	-	-	39,111	17.4 %
Foreign Debt	-	7,402	-	-	7,402	3.3 %
State and Local Government	-	1,323	-	-	1,323	0.6 %
Other - Asset Backed	-	2,977	-	-	2,977	1.3 %
Subtotal - Fixed Income	-	87,727	-	-	87,727	39.0 %
Real Estate	-	-	4,844	-	4,844	2.2 %
Alternative Investments	-	-	7,569	-	7,569	3.4 %
Securities Lending	-	14,806	-	-	14,806	6.6 %
Securities Lending Collateral (a)	-	-	-	(16,058)	(16,058)	(7.1)%
Cash and Cash Equivalents (b)	-	7,389	-	93	7,482	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	36	36	- %
Total	$ 108,583	$ 119,551	$ 12,413	$ (15,929)	$ 224,618	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following tables set forth a reconciliation of changes in the fair value of real estate and alternative investments classified as Level 3 in the fair value hierarchy for pension assets by Registrant Subsidiary:

APCo	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2010	$ 12,623	$ 14,739	$ 27,362
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(1,563)	412	(1,151)
Relating to Assets Sold During the Period	-	134	134
Purchases and Sales	-	1,996	1,996
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 11,060	$ 17,281	$ 28,341

I&M	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2010	$ 10,094	$ 11,786	$ 21,880
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(352)	556	204
Relating to Assets Sold During the Period	-	181	181
Purchases and Sales	-	2,697	2,697
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 9,742	$ 15,220	$ 24,962

OPCo	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2010	$ 20,125	$ 23,498	$ 43,623
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(2,886)	557	(2,329)
Relating to Assets Sold During the Period	-	181	181
Purchases and Sales	-	2,697	2,697
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 17,239	$ 26,933	$ 44,172

PSO	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2010	$ 5,770	$ 6,737	$ 12,507
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(1,164)	75	(1,089)
Relating to Assets Sold During the Period	-	24	24
Purchases and Sales	-	361	361
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 4,606	$ 7,197	$ 11,803

SWEPCo	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2010	$ 5,654	$ 6,602	$ 12,256
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(810)	156	(654)
Relating to Assets Sold During the Period	-	51	51
Purchases and Sales	-	760	760
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 4,844	$ 7,569	$ 12,413

The following tables present the classification of OPEB plan assets within the fair value hierarchy by Registrant Subsidiary at December 31, 2010:

APCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 97,469	$ -	$ -	$ -	$ 97,469	40.0 %
International	36,792	-	-	-	36,792	15.1 %
Common Collective Trust - Global	-	19,153	-	-	19,153	7.9 %
Subtotal - Equities	134,261	19,153	-	-	153,414	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	7,966	-	-	7,966	3.3 %
United States Government and Agency Securities	-	15,636	-	-	15,636	6.4 %
Corporate Debt	-	18,365	-	-	18,365	7.5 %
Foreign Debt	-	4,140	-	-	4,140	1.7 %
State and Local Government	-	583	-	-	583	0.2 %
Other - Asset Backed	-	158	-	-	158	0.1 %
Subtotal - Fixed Income	-	46,848	-	-	46,848	19.2 %
Trust Owned Life Insurance:						
International Equities	-	8,189	-	-	8,189	3.3 %
United States Bonds	-	27,130	-	-	27,130	11.1 %
Cash and Cash Equivalents (a)	3,422	4,179	-	143	7,744	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	446	446	0.2 %
Total	$ 137,683	$ 105,499	$ -	$ 589	$ 243,771	100.0 %

I&M

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 75,446	$ -	$ -	$ -	$ 75,446	40.0 %
International	28,479	-	-	-	28,479	15.1 %
Common Collective Trust - Global	-	14,825	-	-	14,825	7.9 %
Subtotal - Equities	103,925	14,825	-	-	118,750	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	6,166	-	-	6,166	3.3 %
United States Government and Agency Securities	-	12,103	-	-	12,103	6.4 %
Corporate Debt	-	14,215	-	-	14,215	7.5 %
Foreign Debt	-	3,204	-	-	3,204	1.7 %
State and Local Government	-	452	-	-	452	0.2 %
Other - Asset Backed	-	122	-	-	122	0.1 %
Subtotal - Fixed Income	-	36,262	-	-	36,262	19.2 %
Trust Owned Life Insurance:						
International Equities	-	6,338	-	-	6,338	3.3 %
United States Bonds	-	21,000	-	-	21,000	11.1 %
Cash and Cash Equivalents (a)	2,649	3,234	-	111	5,994	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	346	346	0.2 %
Total	$ 106,574	$ 81,659	$ -	$ 457	$ 188,690	100.0 %

OPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 133,225	$ -	$ -	$ -	$ 133,225	40.0 %
International	50,290	-	-	-	50,290	15.1 %
Common Collective Trust - Global	-	26,179	-	-	26,179	7.9 %
Subtotal - Equities	183,515	26,179	-	-	209,694	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	10,889	-	-	10,889	3.3 %
United States Government and Agency Securities	-	21,372	-	-	21,372	6.4 %
Corporate Debt	-	25,102	-	-	25,102	7.5 %
Foreign Debt	-	5,658	-	-	5,658	1.7 %
State and Local Government	-	797	-	-	797	0.2 %
Other - Asset Backed	-	216	-	-	216	0.1 %
Subtotal - Fixed Income	-	64,034	-	-	64,034	19.2 %
Trust Owned Life Insurance:						
International Equities	-	11,192	-	-	11,192	3.3 %
United States Bonds	-	37,082	-	-	37,082	11.1 %
Cash and Cash Equivalents (a)	4,678	5,712	-	195	10,585	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	611	611	0.2 %
Total	$ 188,193	$ 144,199	$ -	$ 806	$ 333,198	100.0 %

PSO

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 33,555	$ -	$ -	$ -	$ 33,555	40.0 %
International	12,666	-	-	-	12,666	15.1 %
Common Collective Trust - Global	-	6,593	-	-	6,593	7.9 %
Subtotal - Equities	46,221	6,593	-	-	52,814	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	2,742	-	-	2,742	3.3 %
United States Government and Agency Securities	-	5,382	-	-	5,382	6.4 %
Corporate Debt	-	6,322	-	-	6,322	7.5 %
Foreign Debt	-	1,425	-	-	1,425	1.7 %
State and Local Government	-	201	-	-	201	0.2 %
Other - Asset Backed	-	54	-	-	54	0.1 %
Subtotal - Fixed Income	-	16,126	-	-	16,126	19.2 %
Trust Owned Life Insurance:						
International Equities	-	2,819	-	-	2,819	3.3 %
United States Bonds	-	9,339	-	-	9,339	11.1 %
Cash and Cash Equivalents (a)	1,178	1,438	-	49	2,665	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	154	154	0.2 %
Total	$ 47,399	$ 36,315	$ -	$ 203	$ 83,917	100.0 %

SWEPCo

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 37,225	$ -	$ -	$ -	$ 37,225	40.0 %
International	14,051	-	-	-	14,051	15.1 %
Common Collective Trust - Global	-	7,314	-	-	7,314	7.9 %
Subtotal - Equities	51,276	7,314	-	-	58,590	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	3,042	-	-	3,042	3.3 %
United States Government and Agency Securities	-	5,971	-	-	5,971	6.4 %
Corporate Debt	-	7,014	-	-	7,014	7.5 %
Foreign Debt	-	1,581	-	-	1,581	1.7 %
State and Local Government	-	223	-	-	223	0.2 %
Other - Asset Backed	-	60	-	-	60	0.1 %
Subtotal - Fixed Income	-	17,891	-	-	17,891	19.2 %
Trust Owned Life Insurance:						
International Equities	-	3,127	-	-	3,127	3.3 %
United States Bonds	-	10,361	-	-	10,361	11.1 %
Cash and Cash Equivalents (a)	1,307	1,596	-	55	2,958	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	170	170	0.2 %
Total	$ 52,583	$ 40,289	$ -	$ 225	$ 93,097	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

The determination of pension expense or income is based 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.

Accumulated Benefit Obligation	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Qualified Pension Plan	$ 672,967	$ 569,855	$ 1,005,608	$ 269,230	$ 269,809
Nonqualified Pension Plans	234	168	821	1,368	1,223
Total as of December 31, 2011	$ 673,201	$ 570,023	$ 1,006,429	$ 270,598	$ 271,032

Accumulated Benefit Obligation	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Qualified Pension Plan	$ 646,513	$ 551,702	$ 973,802	$ 261,535	$ 260,838
Nonqualified Pension Plans	221	994	799	1,326	1,133
Total as of December 31, 2010	$ 646,734	$ 552,696	$ 974,601	$ 262,861	$ 261,971

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans at December 31, 2011 and 2010 were as follows:

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Projected Benefit Obligation	$ 681,450	$ 581,677	$ 1,020,890	$ 277,448	$ 277,594
Accumulated Benefit Obligation	$ 673,201	$ 570,023	$ 1,006,429	$ 270,598	$ 271,032
Fair Value of Plan Assets	570,756	503,926	925,939	245,769	255,861
Underfunded Accumulated Benefit Obligation as of December 31, 2011	$ (102,445)	$ (66,097)	$ (80,490)	$ (24,829)	$ (15,171)

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Projected Benefit Obligation	$ 652,219	$ 560,982	$ 984,089	$ 268,180	$ 267,206
Accumulated Benefit Obligation	$ 646,734	$ 552,696	$ 974,601	$ 262,861	$ 261,971
Fair Value of Plan Assets	512,836	451,688	799,281	213,576	224,618
Underfunded Accumulated Benefit Obligation as of December 31, 2010	$ (133,898)	$ (101,008)	$ (175,320)	$ (49,285)	$ (37,353)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments for the unfunded plan and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may be made to the trust to maintain the funded status of the plan. The contributions to the OPEB plans are generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided in agreements with state regulatory authorities, plus the additional discretionary contribution of the Medicare subsidy receipts. The following table provides the estimated contributions and payments by Registrant Subsidiary for 2012:

Company	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
APCo	$ 33,442	$ 16,775
I&M	23,938	13,465
OPCo	39,095	19,705
PSO	11,612	5,982
SWEPCo	9,089	7,089

The tables below reflect the total benefits expected to be paid from the plan or from the Registrant Subsidiary's assets. The payments include the participants' contributions to the plan for their share of the cost. In December 2011, the prescription drug plan was amended for certain participants. The impact of the change is reflected in the Benefit Plan Obligation table as a plan amendment. As a result of this amendment to the plan, the Medicare subsidy receipts in the following table are reduced from prior published estimates. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2012	$ 44,506	$ 34,963	$ 69,978	$ 19,989	$ 19,329
2013	45,202	35,686	72,422	20,472	20,281
2014	47,192	37,289	76,712	22,199	22,080
2015	46,327	37,831	75,063	22,020	22,288
2016	48,178	39,781	75,042	21,847	22,331
Years 2017 to 2021, in Total	248,647	213,381	371,555	113,723	115,691

Other Postretirement Benefit Plans: Benefit Payments	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2012	$ 27,515	$ 17,849	$ 36,517	$ 7,833	$ 8,302
2013	27,741	18,289	36,412	8,120	8,628
2014	28,782	19,085	37,271	8,438	9,179
2015	29,668	20,117	38,306	8,934	9,598
2016	30,657	21,358	39,774	9,467	10,214
Years 2017 to 2021, in Total	168,810	123,258	218,695	54,491	61,146

Other Postretirement Benefit Plans: Medicare Subsidy Receipts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2012	$ 1,777	$ 1,096	$ 2,276	$ 618	$ 586
2013	272	28	43	-	-
2014	287	27	48	-	-
2015	298	26	59	-	-
2016	307	26	67	-	-
Years 2017 to 2021, in Total	1,578	110	536	-	-

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost by Registrant Subsidiary for the years ended December 31, 2011, 2010 and 2009:

APCo	**Pension Plans**			**Other Postretirement Benefit Plans**		
	Years Ended December 31,					
	2011	**2010**	**2009**	**2011**	**2010**	**2009**
	(in thousands)					
Service Cost	$ 7,199	$ 12,908	$ 12,689	$ 4,983	$ 5,722	$ 5,142
Interest Cost	32,293	33,956	34,050	19,468	20,300	19,710
Expected Return on Plan Assets	(41,833)	(43,805)	(44,885)	(17,985)	(17,628)	(13,531)
Amortization of Transition Obligation	-	-	-	1,167	5,244	5,244
Amortization of Prior Service Cost (Credit)	917	917	917	(171)	-	-
Amortization of Net Actuarial Loss	16,570	11,842	7,688	5,839	5,410	7,666
Net Periodic Benefit Cost	15,146	15,818	10,459	13,301	19,048	24,231
Capitalized Portion	(5,604)	(6,058)	(3,661)	(4,921)	(7,295)	(8,481)
Net Periodic Benefit Cost Recognized as Expense	$ 9,542	$ 9,760	$ 6,798	$ 8,380	$ 11,753	$ 15,750

I&M	**Pension Plans**			**Other Postretirement Benefit Plans**		
	Years Ended December 31,					
	2011	**2010**	**2009**	**2011**	**2010**	**2009**
	(in thousands)					
Service Cost	$ 9,447	$ 15,284	$ 14,002	$ 6,119	$ 6,750	$ 5,990
Interest Cost	27,726	29,085	28,520	13,610	14,164	13,675
Expected Return on Plan Assets	(36,856)	(35,040)	(35,733)	(13,886)	(13,397)	(10,259)
Amortization of Transition Obligation	-	-	-	188	2,814	2,814
Amortization of Prior Service Cost (Credit)	744	744	744	(237)	-	-
Amortization of Net Actuarial Loss	14,144	10,065	6,406	3,566	3,526	5,213
Net Periodic Benefit Cost	15,205	20,138	13,939	9,360	13,857	17,433
Capitalized Portion	(3,163)	(4,028)	(2,732)	(1,947)	(2,771)	(3,417)
Net Periodic Benefit Cost Recognized as Expense	$ 12,042	$ 16,110	$ 11,207	$ 7,413	$ 11,086	$ 14,016

OPCo	**Pension Plans**			**Other Postretirement Benefit Plans**		
	Years Ended December 31,					
	2011	**2010**	**2009**	**2011**	**2010**	**2009**
	(in thousands)					
Service Cost	$ 10,230	$ 17,254	$ 16,538	$ 7,827	$ 8,187	$ 7,347
Interest Cost	48,350	51,900	52,629	25,497	26,498	25,818
Expected Return on Plan Assets	(65,464)	(69,077)	(71,554)	(24,514)	(24,092)	(18,685)
Curtailment	-	-	-	605	-	-
Amortization of Transition Obligation	-	-	-	150	6,642	6,643
Amortization of Prior Service Cost (Credit)	1,474	1,474	1,475	(212)	-	-
Amortization of Net Actuarial Loss	24,828	18,150	11,931	7,298	6,877	9,988
Net Periodic Benefit Cost	19,418	19,701	11,019	16,651	24,112	31,111
Capitalized Portion	(6,932)	(6,843)	(3,901)	(5,944)	(8,334)	(10,913)
Net Periodic Benefit Cost Recognized as Expense	$ 12,486	$ 12,858	$ 7,118	$ 10,707	$ 15,778	$ 20,198

PSO	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	(in thousands)					
Service Cost	$ 5,760	$ 6,052	$ 5,744	$ 2,621	$ 2,815	$ 2,522
Interest Cost	13,285	14,888	15,369	6,046	6,360	6,154
Expected Return on Plan Assets	(17,464)	(19,739)	(20,438)	(6,264)	(6,110)	(4,695)
Amortization of Transition Obligation	-	-	-	-	2,805	2,805
Amortization of Prior Service Credit	(950)	(950)	(1,082)	(75)	-	-
Amortization of Net Actuarial Loss	6,757	5,188	3,487	1,553	1,573	2,348
Net Periodic Benefit Cost	7,388	5,439	3,080	3,881	7,443	9,134
Capitalized Portion	(2,379)	(1,806)	(1,087)	(1,249)	(2,471)	(3,224)
Net Periodic Benefit Cost Recognized as Expense	$ 5,009	$ 3,633	$ 1,993	$ 2,632	$ 4,972	$ 5,910

SWEPCo	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2011	2010	2009	2011	2010	2009
	(in thousands)					
Service Cost	$ 6,573	$ 7,046	$ 6,757	$ 3,029	$ 3,108	$ 2,817
Interest Cost	13,331	15,093	15,557	6,969	6,940	6,735
Expected Return on Plan Assets	(18,380)	(19,489)	(20,083)	(7,200)	(6,646)	(5,120)
Amortization of Transition Obligation	-	-	-	-	2,461	2,461
Amortization of Prior Service Cost (Credit)	(795)	(796)	(916)	258	-	-
Amortization of Net Actuarial Loss	6,759	5,242	3,516	1,785	1,711	2,560
Net Periodic Benefit Cost	7,488	7,096	4,831	4,841	7,574	9,453
Capitalized Portion	(2,636)	(2,406)	(1,546)	(1,704)	(2,568)	(3,025)
Net Periodic Benefit Cost Recognized as Expense	$ 4,852	$ 4,690	$ 3,285	$ 3,137	$ 5,006	$ 6,428

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on each Registrant Subsidiary's balance sheet during 2012 are shown in the following tables:

Pension Plan - Components	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Net Actuarial Loss	$ 19,816	$ 16,915	$ 29,690	$ 8,074	$ 8,077
Prior Service Cost (Credit)	475	407	743	(948)	(793)
Total Estimated 2012 Amortization	$ 20,291	$ 17,322	$ 30,433	$ 7,126	$ 7,284
Pension Plans - Expected to be Recorded as					
Regulatory Asset	$ 20,190	$ 16,303	$ 16,299	$ 7,126	$ 7,284
Deferred Income Taxes	35	357	4,947	-	-
Net of Tax AOCI	66	662	9,187	-	-
Total	$ 20,291	$ 17,322	$ 30,433	$ 7,126	$ 7,284

Other Postretirement Benefit Plans - Components	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
Net Actuarial Loss	$ 10,671	$ 7,325	$ 13,951	$ 3,296	$ 3,822
Prior Service Credit	(2,862)	(2,383)	(3,873)	(1,079)	(933)
Transition Obligation	780	132	104	-	-
Total Estimated 2012 Amortization	$ 8,589	$ 5,074	$ 10,182	$ 2,217	$ 2,889
Other Postretirement Benefit Plans - Expected to be Recorded as					
Regulatory Asset	$ 3,049	$ 4,400	$ 4,565	$ 2,217	$ 1,804
Deferred Income Taxes	1,939	236	1,966	-	380
Net of Tax AOCI	3,601	438	3,651	-	705
Total	$ 8,589	$ 5,074	$ 10,182	$ 2,217	$ 2,889

American Electric Power System Retirement Savings Plans

The Registrant Subsidiaries participate in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees who are not members of the United Mine Workers of America (UMWA). This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

The 2009 contributions below for SWEPCo include a legacy savings plan of an acquired subsidiary.

The following table provides the cost for matching contributions to the retirement savings plans by Registrant Subsidiary for the years ended December 31, 2011, 2010 and 2009:

Company	Years Ended December 31, 2011	2010 (in thousands)	2009
APCo	$ 7,432	$ 7,284	$ 8,673
I&M	9,541	8,969	10,315
OPCo	10,166	9,706	11,640
PSO	3,626	3,505	4,083
SWEPCo	4,438	3,866	5,269

UMWA Benefits

APCo, I&M and OPCo provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. APCo, I&M and OPCo administer the health and welfare benefits and pay them from their general assets.

The UMWA pension benefits are administered through a multiemployer plan that is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. Required contributions not made by an employer may result in other employers bearing the unfunded plan obligations, while a withdrawing employer may be subject to a withdrawal liability. UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), which under the Pension Protection Act of 2006 (PPA) was in Seriously Endangered Status for the plan years ending June 30, 2011 and 2010, without utilization of extended amortization provisions. The Plan is required under the PPA to adopt a funding improvement plan by May 25, 2012. Contributions in 2011, 2010 and 2009, which were made under a collective bargaining agreement that expires December 31, 2012, were immaterial and represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2011, 2010 and 2009. Contributions did not include a surcharge, and there are no minimum contributions for future years.

8. BUSINESS SEGMENTS

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business. The Registrant Subsidiaries' other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

The Registrant Subsidiaries are exposed to certain market risks as major power producers and marketers of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrant Subsidiaries due to changes in the underlying market prices or rates. AEPSC, on behalf of the Registrant Subsidiaries, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of the Registrant Subsidiaries.

Risk Management Strategies

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of the Registrant Subsidiaries, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of the Registrant Subsidiaries, enters into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with the Registrant Subsidiaries' commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of the Registrant Subsidiaries, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following tables represent the gross notional volume of the Registrant Subsidiaries' outstanding derivative contracts as of December 31, 2011 and 2010:

Notional Volume of Derivative Instruments
December 31, 2011

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity:						
Power	MWHs	169,459	109,326	229,468	39	49
Coal	Tons	3,714	1,920	8,337	3,574	2,974
Natural Gas	MMBtus	7,923	5,081	10,728	115	145
Heating Oil and Gasoline	Gallons	1,057	525	1,254	618	569
Interest Rate	USD	$ 31,029	$ 19,890	$ 42,093	$ 175	$ 203
Interest Rate and Foreign Currency	USD	$ -	$ 200,000	$ -	$ -	$ 200,069

Notional Volume of Derivative Instruments
December 31, 2010

Primary Risk Exposure	Unit of Measure	APCo	I&M	OPCo	PSO	SWEPCo
				(in thousands)		
Commodity:						
Power	MWHs	194,217	117,862	248,616	21	34
Coal	Tons	11,195	6,571	28,583	4,936	8,777
Natural Gas	MMBtus	2,166	1,302	2,772	15	19
Heating Oil and Gasoline	Gallons	1,054	521	1,243	616	564
Interest Rate	USD	$ 9,541	$ 5,732	$ 12,656	$ 609	$ 793
Interest Rate and Foreign Currency	USD	$ 200,000	$ -	$ -	$ 200,000	$ 189

Fair Value Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify an exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of the Registrant Subsidiaries, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. The Registrant Subsidiaries do not hedge all commodity price risk.

The Registrant Subsidiaries' vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of the Registrant Subsidiaries, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." The Registrant Subsidiaries do not hedge all fuel price risk.

AEPSC, on behalf of the Registrant Subsidiaries, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of the Registrant Subsidiaries, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. The Registrant Subsidiaries do not hedge all interest rate exposure.

At times, the Registrant Subsidiaries are exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of the Registrant Subsidiaries, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrant Subsidiaries do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheet at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrant Subsidiaries also apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrant Subsidiaries reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrant Subsidiaries are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2011 and 2010 balance sheets, the Registrant Subsidiaries netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

	December 31,			
	2011		2010	
Company	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
	(in thousands)			
APCo	$ 4,291	$ 28,964	$ 1,809	$ 16,229
I&M	2,752	18,547	1,087	9,757
OPCo	5,810	39,183	2,314	20,908
PSO	53	130	-	44
SWEPCo	66	124	-	72

The following tables represent the gross fair value of the Registrant Subsidiaries' derivative activity on the balance sheets as of December 31, 2011 and 2010:

Fair Value of Derivative Instruments
December 31, 2011

APCo

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 232,784	$ 1,040	$ -	$ (194,179)	$ 39,645
Long-term Risk Management Assets	99,751	90	-	(60,615)	39,226
Total Assets	332,535	1,130	-	(254,794)	78,871
Current Risk Management Liabilities	235,354	2,767	-	(211,515)	26,606
Long-term Risk Management Liabilities	82,058	350	-	(69,485)	12,923
Total Liabilities	317,412	3,117	-	(281,000)	39,529
Total MTM Derivative Contract Net Assets (Liabilities)	$ 15,123	$ (1,987)	$ -	$ 26,206	$ 39,342

Fair Value of Derivative Instruments
December 31, 2010

APCo

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 267,702	$ 1,956	$ 11,888	$ (228,304)	$ 53,242
Long-term Risk Management Assets	79,560	714	-	(41,854)	38,420
Total Assets	347,262	2,670	11,888	(270,158)	91,662
Current Risk Management Liabilities	262,027	2,363	-	(236,397)	27,993
Long-term Risk Management Liabilities	61,724	701	-	(51,552)	10,873
Total Liabilities	323,751	3,064	-	(287,949)	38,866
Total MTM Derivative Contract Net Assets (Liabilities)	$ 23,511	$ (394)	$ 11,888	$ 17,791	$ 52,796

Fair Value of Derivative Instruments
December 31, 2011

I&M

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 154,628	$ 667	$ -	$ (123,143)	$ 32,152
Long-term Risk Management Assets	68,047	58	-	(38,743)	29,362
Total Assets	222,675	725	-	(161,886)	61,514
Current Risk Management Liabilities	149,466	1,747	-	(134,233)	16,980
Long-term Risk Management Liabilities	52,441	224	10,637	(44,431)	18,871
Total Liabilities	201,907	1,971	10,637	(178,664)	35,851
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,768	$ (1,246)	$ (10,637)	$ 16,778	$ 25,663

Fair Value of Derivative Instruments
December 31, 2010

I&M

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 162,896	$ 1,151	$ -	$ (136,521)	$ 27,526
Long-term Risk Management Assets	56,154	429	-	(25,098)	31,485
Total Assets	219,050	1,580	-	(161,619)	59,011
Current Risk Management Liabilities	156,750	1,421	-	(141,386)	16,785
Long-term Risk Management Liabilities	37,039	421	-	(30,930)	6,530
Total Liabilities	193,789	1,842	-	(172,316)	23,315
Total MTM Derivative Contract Net Assets (Liabilities)	$ 25,261	$ (262)	$ -	$ 10,697	$ 35,696

Fair Value of Derivative Instruments
December 31, 2011

OPCo

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**	**Other (b)**	**Total**
			(in thousands)		
Current Risk Management Assets	$ 325,904	$ 1,409	$ -	$ (273,020)	$ 54,293
Long-term Risk Management Assets	136,519	122	-	(83,027)	53,614
Total Assets	462,423	1,531	-	(356,047)	107,907
Current Risk Management Liabilities	329,307	3,712	-	(296,458)	36,561
Long-term Risk Management Liabilities	112,454	474	-	(95,038)	17,890
Total Liabilities	441,761	4,186	-	(391,496)	54,451
Total MTM Derivative Contract Net Assets (Liabilities)	$ 20,662	$ (2,655)	$ -	$ 35,449	$ 53,456

Fair Value of Derivative Instruments
December 31, 2010

OPCo

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**	**Other (b)**	**Total**
			(in thousands)		
Current Risk Management Assets	$ 412,637	$ 2,480	$ -	$ (360,570)	$ 54,547
Long-term Risk Management Assets	108,946	915	-	(59,760)	50,101
Total Assets	521,583	3,395	-	(420,330)	104,648
Current Risk Management Liabilities	406,175	3,025	-	(371,067)	38,133
Long-term Risk Management Liabilities	85,901	897	-	(72,172)	14,626
Total Liabilities	492,076	3,922	-	(443,239)	52,759
Total MTM Derivative Contract Net Assets (Liabilities)	$ 29,507	$ (527)	$ -	$ 22,909	$ 51,889

Fair Value of Derivative Instruments
December 31, 2011

PSO

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 6,980	$ -	$ -	$ (6,415)	$ 565
Long-term Risk Management Assets	914	-	-	(600)	314
Total Assets	7,894	-	-	(7,015)	879
Current Risk Management Liabilities	7,665	107	-	(6,492)	1,280
Long-term Risk Management Liabilities	1,930	-	-	(600)	1,330
Total Liabilities	9,595	107	-	(7,092)	2,610
Total MTM Derivative Contract Net Assets (Liabilities)	$ (1,701)	$ (107)	$ -	$ 77	$ (1,731)

Fair Value of Derivative Instruments
December 31, 2010

PSO

Balance Sheet Location	Risk Management Contracts	Hedging Contracts			
	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 19,174	$ 134	$ 13,558	$ (18,641)	$ 14,225
Long-term Risk Management Assets	1,944	-	-	(1,692)	252
Total Assets	21,118	134	13,558	(20,333)	14,477
Current Risk Management Liabilities	19,607	-	-	(18,685)	922
Long-term Risk Management Liabilities	1,889	-	-	(1,692)	197
Total Liabilities	21,496	-	-	(20,377)	1,119
Total MTM Derivative Contract Net Assets (Liabilities)	$ (378)	$ 134	$ 13,558	$ 44	$ 13,358

Fair Value of Derivative Instruments
December 31, 2011

SWEPCo

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 6,327	$ -	$ 3	$ (5,885)	$ 445
Long-term Risk Management Assets	818	-	-	(536)	282
Total Assets	7,145	-	3	(6,421)	727
Current Risk Management Liabilities	11,062	97	19,143	(5,943)	24,359
Long-term Risk Management Liabilities	757	-	-	(536)	221
Total Liabilities	11,819	97	19,143	(6,479)	24,580
Total MTM Derivative Contract Net Assets (Liabilities)	$ (4,674)	$ (97)	$ (19,140)	$ 58	$ (23,853)

Fair Value of Derivative Instruments
December 31, 2010

SWEPCo

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)	Other (b)	Total
			(in thousands)		
Current Risk Management Assets	$ 33,284	$ 123	$ -	$ (32,198)	$ 1,209
Long-term Risk Management Assets	3,346	-	5	(2,913)	438
Total Assets	36,630	123	5	(35,111)	1,647
Current Risk Management Liabilities	36,338	-	-	(32,271)	4,067
Long-term Risk Management Liabilities	3,250	-	-	(2,912)	338
Total Liabilities	39,588	-	-	(35,183)	4,405
Total MTM Derivative Contract Net Assets (Liabilities)	$ (2,958)	$ 123	$ 5	$ 72	$ (2,758)

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.

The tables below present the Registrant Subsidiaries' activity of derivative risk management contracts for the years ended December 31, 2011, 2010 and 2009:

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2011

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 2,843	$ 12,786	$ 27,292	$ 297	$ 547
Sales to AEP Affiliates	154	92	196	3	4
Fuel and Other Consumables Used for Electric Generation	-	-	(2)	-	-
Regulatory Assets (a)	373	(1,470)	(17,928)	(1,421)	(1,709)
Regulatory Liabilities (a)	2,552	(5,178)	(105)	708	(118)
Total Gain (Loss) on Risk Management Contracts	$ 5,922	$ 6,230	$ 9,453	$ (413)	$ (1,276)

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2010

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 5,057	$ 21,834	$ 40,893	$ 3,156	$ 3,880
Sales to AEP Affiliates	(2,379)	(2,471)	5,043	(794)	(1,523)
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Regulatory Assets (a)	(372)	(186)	(5,788)	46	(2,902)
Regulatory Liabilities (a)	27,790	8,217	3,451	878	351
Total Gain (Loss) on Risk Management Contracts	$ 30,096	$ 27,394	$ 43,599	$ 3,286	$ (194)

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2009

Location of Gain (Loss)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Electric Generation, Transmission and Distribution Revenues	$ 16,213	$ 39,188	$ 59,313	$ (94)	$ 44
Sales to AEP Affiliates	(8,978)	(5,450)	(6,770)	912	750
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Regulatory Assets (a)	-	(5,837)	(22,065)	(331)	(73)
Regulatory Liabilities (a)	6,908	(2,394)	(7,805)	(1,280)	190
Total Gain (Loss) on Risk Management Contracts	$ 14,143	$ 25,507	$ 22,673	$ (793)	$ 911

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions (APCo, I&M, PSO, the non-Texas portion of SWEPCo generation and, beginning in the second quarter of 2009, the Texas portion of SWEPCo generation) for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations." SWEPCo re-applied the accounting guidance for "Regulated Operations" for the generation portion of SWEPCo's Texas retail jurisdiction effective the second quarter of 2009.

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

The Registrant Subsidiaries record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income. During 2011, 2010 and 2009, the Registrant Subsidiaries did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrant Subsidiaries initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. The Registrant Subsidiaries recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal, natural gas and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2011, 2010 and 2009, APCo, I&M and OPCo designated commodity derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2011, 2010 and 2009, the Registrant Subsidiaries designated heating oil and gasoline derivatives as cash flow hedges.

The Registrant Subsidiaries reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2011, APCo, I&M and SWEPCo designated interest rate derivatives as cash flow hedges. During 2010, APCo and PSO designated interest rate derivatives as cash flow hedges. During 2009, OPCo designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During 2011, 2010 and 2009, SWEPCo designated foreign currency derivatives as cash flow hedges.

During 2009, OPCo recognized a $6 million gain in Interest Expense related to hedge ineffectiveness on interest rate derivatives designated in cash flow hedge strategies. During 2011, 2010 and 2009, hedge ineffectiveness was immaterial or nonexistent for all of the other cash flow hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2011, 2010 and 2009. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

Commodity Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2010	$ (273)	$ (178)	$ (364)	$ 88	$ 82
Changes in Fair Value Recognized in AOCI	(2,077)	(1,294)	(2,748)	108	102
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	249	544	1,457	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	62	79	425	-	-
Other Operation Expense	(95)	(71)	(160)	(93)	(93)
Maintenance Expense	(169)	(64)	(141)	(62)	(65)
Property, Plant and Equipment	(175)	(90)	(217)	(110)	(88)
Regulatory Assets (a)	1,169	255	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of December 31, 2011	$ (1,309)	$ (819)	$ (1,748)	$ (69)	$ (62)

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2010	$ 217	$ (8,507)	$ 10,813	$ 8,406	$ (4,272)
Changes in Fair Value Recognized in AOCI	(373)	(6,913)	-	(475)	(12,438)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Depreciation and Amortization Expense	-	-	4	-	-
Other Operation Expense	-	-	-	-	-
Interest Expense	1,180	955	(1,363)	(713)	1,248
Balance in AOCI as of December 31, 2011	$ 1,024	$ (14,465)	$ 9,454	$ 7,218	$ (15,462)

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2010	$ (56)	$ (8,685)	$ 10,449	$ 8,494	$ (4,190)
Changes in Fair Value Recognized in AOCI	(2,450)	(8,207)	(2,748)	(367)	(12,336)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	249	544	1,457	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	-	-	-
Purchased Electricity for Resale	62	79	425	-	-
Other Operation Expense	(95)	(71)	(160)	(93)	(93)
Maintenance Expense	(169)	(64)	(141)	(62)	(65)
Depreciation and Amortization Expense	-	-	4	-	-
Interest Expense	1,180	955	(1,363)	(713)	1,248
Property, Plant and Equipment	(175)	(90)	(217)	(110)	(88)
Regulatory Assets (a)	1,169	255	-	-	-
Regulatory Liabilities (a)	-	-	-	-	-
Balance in AOCI as of December 31, 2011	$ (285)	$ (15,284)	$ 7,706	$ 7,149	$ (15,524)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

Commodity Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2009	$ (743)	$ (382)	$ (742)	$ (78)	$ 112
Changes in Fair Value Recognized in AOCI	(1,450)	(901)	(1,958)	77	69
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	51	87	229	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	(13)	197	-
Purchased Electricity for Resale	393	895	2,338	-	-
Other Operation Expense	(43)	(31)	(72)	(39)	(44)
Maintenance Expense	(70)	(28)	(54)	(24)	(23)
Property, Plant and Equipment	(71)	(36)	(87)	(45)	(32)
Regulatory Assets (a)	1,660	218	-	-	-
Regulatory Liabilities (a)	-	-	(5)	-	-
Balance in AOCI as of December 31, 2010	$ (273)	$ (178)	$ (364)	$ 88	$ 82

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2009	$ (6,450)	$ (9,514)	$ 12,172	$ (521)	$ (5,047)
Changes in Fair Value Recognized in AOCI	5,042	-	-	8,813	(74)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Depreciation and Amortization Expense	-	-	4	-	-
Other Operation Expense	-	-	-	-	21
Interest Expense	1,625	1,007	(1,363)	114	828
Balance in AOCI as of December 31, 2010	$ 217	$ (8,507)	$ 10,813	$ 8,406	$ (4,272)

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2009	$ (7,193)	$ (9,896)	$ 11,430	$ (599)	$ (4,935)
Changes in Fair Value Recognized in AOCI	3,592	(901)	(1,958)	8,890	(5)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	51	87	229	-	-
Fuel and Other Consumables Used for Electric Generation	-	-	(13)	197	-
Purchased Electricity for Resale	393	895	2,338	-	-
Other Operation Expense	(43)	(31)	(72)	(39)	(23)
Maintenance Expense	(70)	(28)	(54)	(24)	(23)
Depreciation and Amortization Expense	-	-	4	-	-
Interest Expense	1,625	1,007	(1,363)	114	828
Property, Plant and Equipment	(71)	(36)	(87)	(45)	(32)
Regulatory Assets (a)	1,660	218	-	-	-
Regulatory Liabilities (a)	-	-	(5)	-	-
Balance in AOCI as of December 31, 2010	$ (56)	$ (8,685)	$ 10,449	$ 8,494	$ (4,190)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2009

Commodity Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2008	$ 2,726	$ 1,482	$ 3,429	$ -	$ -
Changes in Fair Value Recognized in AOCI	(669)	(435)	(984)	5	190
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	(1,646)	(3,189)	(8,991)	-	-
Fuel and Other Consumables Used for Electric Generation	(95)	(50)	(108)	(49)	(54)
Purchased Electricity for Resale	1,093	2,142	5,982	-	-
Other Operation Expense	-	-	-	-	-
Maintenance Expense	-	-	-	-	-
Property, Plant and Equipment	(58)	(29)	(70)	(34)	(24)
Regulatory Assets (a)	4,003	481	-	-	-
Regulatory Liabilities (a)	(6,097)	(784)	-	-	-
Balance in AOCI as of December 31, 2009	$ (743)	$ (382)	$ (742)	$ (78)	$ 112

Interest Rate and Foreign Currency Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2008	$ (8,118)	$ (10,521)	$ 1,752	$ (704)	$ (5,924)
Changes in Fair Value Recognized in AOCI	(1)	-	10,915	-	49
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Depreciation and Amortization Expense	-	(4)	4	-	-
Other Operation Expense	-	-	-	-	-
Interest Expense	1,669	1,011	(499)	183	828
Balance in AOCI as of December 31, 2009	$ (6,450)	$ (9,514)	$ 12,172	$ (521)	$ (5,047)

Total Contracts	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance in AOCI as of December 31, 2008	$ (5,392)	$ (9,039)	$ 5,181	$ (704)	$ (5,924)
Changes in Fair Value Recognized in AOCI	(670)	(435)	9,931	5	239
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:					
Electric Generation, Transmission and Distribution Revenues	(1,646)	(3,189)	(8,991)	-	-
Fuel and Other Consumables Used for Electric Generation	(95)	(50)	(108)	(49)	(54)
Purchased Electricity for Resale	1,093	2,142	5,982	-	-
Other Operation Expense	-	-	-	-	-
Maintenance Expense	-	-	-	-	-
Depreciation and Amortization Expense	-	(4)	4	-	-
Interest Expense	1,669	1,011	(499)	183	828
Property, Plant and Equipment	(58)	(29)	(70)	(34)	(24)
Regulatory Assets (a)	4,003	481	-	-	-
Regulatory Liabilities (a)	(6,097)	(784)	-	-	-
Balance in AOCI as of December 31, 2009	$ (7,193)	$ (9,896)	$ 11,430	$ (599)	$ (4,935)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets at December 31, 2011 and 2010 were:

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets December 31, 2011

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			
APCo	$ 431	$ -	$ 2,418	$ -	$ (1,309)	$ 1,024
I&M	277	-	1,523	10,637	(819)	(14,465)
OPCo	584	-	3,239	-	(1,748)	9,454
PSO	-	-	107	-	(69)	7,218
SWEPCo	-	3	97	19,143	(62)	(15,462)

	Expected to be Reclassified to Net Income During the Next Twelve Months		
Company	Commodity	Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
	(in thousands)		(in months)
APCo	$ (1,140)	$ (1,052)	29
I&M	(712)	(595)	29
OPCo	(1,518)	1,359	29
PSO	(70)	759	12
SWEPCo	(63)	(1,864)	12

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets
December 31, 2010

	Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Company	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
			(in thousands)			
APCo	$ 333	$ 11,888	$ 727	$ -	$ (273)	$ 217
I&M	175	-	437	-	(178)	(8,507)
OPCo	403	-	930	-	(364)	10,813
PSO	134	13,558	-	-	88	8,406
SWEPCo	123	5	-	-	82	(4,272)

	Expected to be Reclassified to Net Income During the Next Twelve Months	
Company	Commodity	Interest Rate and Foreign Currency
	(in thousands)	
APCo	$ (280)	$ (1,173)
I&M	(184)	(955)
OPCo	(373)	1,359
PSO	88	735
SWEPCo	82	(829)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

AEPSC, on behalf of the Registrant Subsidiaries, limits credit risk in their wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of the Registrant Subsidiaries, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEPSC, on behalf of the Registrant Subsidiaries, uses standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, the Registrant Subsidiaries are obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. The Registrant Subsidiaries have not experienced a downgrade below investment grade. The following tables represent: (a) the Registrant Subsidiaries' aggregate fair values of such derivative contracts, (b) the amount of collateral the Registrant Subsidiaries would have been required to post for all derivative and non-derivative contracts if credit ratings of the Registrant Subsidiaries had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2011 and 2010:

	December 31, 2011		
Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
APCo	$ 10,007	$ 6,211	$ 6,211
I&M	6,418	3,983	3,983
OPCo	13,550	8,410	8,410
PSO	-	856	414
SWEPCo	-	1,128	522

	December 31, 2010		
Company	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral the Registrant Subsidiaries Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
APCo	$ 6,594	$ 12,607	$ 12,574
I&M	3,965	7,581	7,561
OPCo	8,441	16,138	16,095
PSO	16	1,785	1,385
SWEPCo	19	2,139	1,659

As of December 31, 2011 and 2010, the Registrant Subsidiaries were not required to post any collateral.

In addition, a majority of the Registrant Subsidiaries' non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management does not anticipate a non-performance event under these provisions. The following tables represent: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by the Registrant Subsidiaries and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering the Registrant Subsidiaries' contractual netting arrangements as of December 31, 2011 and 2010:

	December 31, 2011		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
APCo	$ 76,868	$ 8,107	$ 27,603
I&M	59,936	5,200	28,339
OPCo	104,091	10,978	37,380
PSO	142	-	61
SWEPCo	19,322	-	19,220

	December 31, 2010		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
APCo	$ 76,810	$ 6,637	$ 23,748
I&M	46,188	3,991	14,280
OPCo	98,343	8,496	30,420
PSO	60	-	28
SWEPCo	75	-	37

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current 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 could be realized in a current market exchange.

The book values and fair values of Long-term Debt for the Registrant Subsidiaries as of December 31, 2011 and 2010 are summarized in the following table:

	December 31,			
	2011		2010	
Company	Book Value	Fair Value	Book Value	Fair Value
		(in thousands)		
APCo	$ 3,726,251	$ 4,431,912	$ 3,561,141	$ 3,878,557
I&M	2,057,675	2,339,344	2,004,226	2,169,520
OPCo	4,054,148	4,665,739	4,168,352	4,516,499
PSO	947,364	1,123,306	971,186	1,040,656
SWEPCo	1,728,637	2,019,094	1,769,520	1,931,516

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments at December 31, 2011 and 2010:

	December 31, 2011			December 31, 2010		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in thousands)					
Cash and Cash Equivalents	$ 18,229	$ -	$ -	$ 20,039	$ -	$ -
Fixed Income Securities:						
United States Government	543,506	60,946	(547)	461,084	22,582	(1,489)
Corporate Debt	53,979	4,932	(1,536)	59,463	3,716	(1,905)
State and Local Government	329,986	(430)	(2,236)	340,786	(975)	(340)
Subtotal Fixed Income Securities	927,471	65,448	(4,319)	861,333	25,323	(3,734)
Equity Securities - Domestic	646,032	214,748	(79,536)	633,855	183,447	(122,889)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,591,732	$ 280,196	$ (83,855)	$ 1,515,227	$ 208,770	$ (126,623)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31, 2011	2010	2009
	(in thousands)		
Proceeds from Investment Sales	$ 1,110,909	$ 1,361,813	$ 712,742
Purchases of Investments	1,166,690	1,414,473	770,919
Gross Realized Gains on Investment Sales	33,382	11,570	28,218
Gross Realized Losses on Investment Sales	22,159	2,087	1,241

The adjusted cost of debt securities was $862 million and $835 million as of December 31, 2011 and 2010, respectively. The adjusted cost of equity securities was $431 million and $451 million as of December 31, 2011 and 2010, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2011 was as follows:

	Fair Value of Debt Securities
	(in thousands)
Within 1 year	$ 62,383
1 year – 5 years	284,942
5 years – 10 years	349,587
After 10 years	230,559
Total	$ 927,471

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, the Registrant Subsidiaries' financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 4,680	$ 302,128	$ 25,423	$ (255,324)	$ 76,907
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,095	-	(664)	431
De-designated Risk Management Contracts (b)	-	-	-	1,533	1,533
Total Risk Management Assets	$ 4,680	$ 303,223	$ 25,423	$ (254,455)	$ 78,871
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 2,535	$ 291,194	$ 23,379	$ (279,997)	$ 37,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	3,009	73	(664)	2,418
Total Risk Management Liabilities	$ 2,535	$ 294,203	$ 23,452	$ (280,661)	$ 39,529

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

APCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 1,686	$ 330,605	$ 13,791	$ (270,012)	$ 76,070
Cash Flow Hedges:					
Commodity Hedges (a)	-	2,591	-	(2,258)	333
Interest Rate/Foreign Currency Hedges	-	11,888	-	-	11,888
De-designated Risk Management Contracts (b)	-	-	-	3,371	3,371
Total Risk Management Assets	$ 1,686	$ 345,084	$ 13,791	$ (268,899)	$ 91,662
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 1,653	$ 312,258	$ 8,660	$ (284,432)	$ 38,139
Cash Flow Hedges:					
Commodity Hedges (a)	-	2,985	-	(2,258)	727
Total Risk Management Liabilities	$ 1,653	$ 315,243	$ 8,660	$ (286,690)	$ 38,866

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 3,001	$ 203,175	$ 16,305	$ (162,227)	$ 60,254
Cash Flow Hedges:					
Commodity Hedges (a)	-	702	-	(425)	277
De-designated Risk Management Contracts (b)	-	-	-	983	983
Total Risk Management Assets	3,001	203,877	16,305	(161,669)	61,514
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	-	5,431	-	12,798	18,229
Fixed Income Securities:					
United States Government	-	543,506	-	-	543,506
Corporate Debt	-	53,979	-	-	53,979
State and Local Government	-	329,986	-	-	329,986
Subtotal Fixed Income Securities	-	927,471	-	-	927,471
Equity Securities - Domestic (e)	646,032	-	-	-	646,032
Total Spent Nuclear Fuel and Decommissioning Trusts	646,032	932,902	-	12,798	1,591,732
Total Assets	$ 649,033	$ 1,136,779	$ 16,305	$ (148,871)	$ 1,653,246
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 1,626	$ 185,092	$ 14,995	$ (178,022)	$ 23,691
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,901	47	(425)	1,523
Interest Rate/Foreign Currency Hedges	-	10,637	-	-	10,637
Total Risk Management Liabilities	$ 1,626	$ 197,630	$ 15,042	$ (178,447)	$ 35,851

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

I&M

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 1,014	$ 209,031	$ 8,295	$ (161,531)	$ 56,809
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,533	-	(1,358)	175
De-designated Risk Management Contracts (b)	-	-	-	2,027	2,027
Total Risk Management Assets	1,014	210,564	8,295	(160,862)	59,011
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (d)	-	7,898	-	12,141	20,039
Fixed Income Securities:					
United States Government	-	461,084	-	-	461,084
Corporate Debt	-	59,463	-	-	59,463
State and Local Government	-	340,786	-	-	340,786
Subtotal Fixed Income Securities	-	861,333	-	-	861,333
Equity Securities - Domestic (e)	633,855	-	-	-	633,855
Total Spent Nuclear Fuel and Decommissioning Trusts	633,855	869,231	-	12,141	1,515,227
Total Assets	$ 634,869	$ 1,079,795	$ 8,295	$ (148,721)	$ 1,574,238
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 994	$ 186,898	$ 5,187	$ (170,201)	$ 22,878
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,795	-	(1,358)	437
Total Risk Management Liabilities	$ 994	$ 188,693	$ 5,187	$ (171,559)	$ 23,315

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (c)	$ 26	$ -	$ -	$ 22	$ 48
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	6,339	421,249	34,425	(356,766)	105,247
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,483	-	(899)	584
De-designated Risk Management Contracts (b)	-	-	-	2,076	2,076
Total Risk Management Assets	6,339	422,732	34,425	(355,589)	107,907
Total Assets	$ 6,365	$ 422,732	$ 34,425	$ (355,567)	$ 107,955
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 3,433	$ 406,259	$ 31,659	$ (390,139)	$ 51,212
Cash Flow Hedges:					
Commodity Hedges (a)	-	4,038	100	(899)	3,239
Total Risk Management Liabilities	$ 3,433	$ 410,297	$ 31,759	$ (391,038)	$ 54,451

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

OPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Other Cash Deposits (c)	$ 26	$ -	$ -	$ -	$ 26
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	2,158	500,259	17,659	(420,146)	99,930
Cash Flow Hedges:					
Commodity Hedges (a)	-	3,295	-	(2,892)	403
De-designated Risk Management Contracts (b)	-	-	-	4,315	4,315
Total Risk Management Assets	2,158	503,554	17,659	(418,723)	104,648
Total Assets	$ 2,184	$ 503,554	$ 17,659	$ (418,723)	$ 104,674
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 2,116	$ 477,377	$ 11,076	$ (438,740)	$ 51,829
Cash Flow Hedges:					
Commodity Hedges (a)	-	3,822	-	(2,892)	930
Total Risk Management Liabilities	$ 2,116	$ 481,199	$ 11,076	$ (441,632)	$ 52,759

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 97	$ 7,797	$ -	$ (7,015)	$ 879
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 53	$ 9,542	$ -	$ (7,092)	$ 2,503
Cash Flow Hedges:					
Commodity Hedges	-	107	-	-	107
Total Risk Management Liabilities	$ 53	$ 9,649	$ -	$ (7,092)	$ 2,610

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

PSO

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ -	$ 21,119	$ 1	$ (20,335)	$ 785
Cash Flow Hedges:					
Commodity Hedges	-	134	-	-	134
Interest Rate/Foreign Currency Hedges	-	13,558	-	-	13,558
Total Risk Management Assets	$ -	$ 34,811	$ 1	$ (20,335)	$ 14,477
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ -	$ 21,498	$ -	$ (20,379)	$ 1,119

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ 122	$ 7,023	$ -	$ (6,421)	$ 724
Cash Flow Hedges:					
Interest Rate/Foreign Currency Hedges	-	3	-	-	3
Total Risk Management Assets	$ 122	$ 7,026	$ -	$ (6,421)	$ 727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ 66	$ 11,753	$ -	$ (6,479)	$ 5,340
Cash Flow Hedges:					
Commodity Hedges	-	97	-	-	97
Interest Rate/Foreign Currency Hedges	-	19,143	-	-	19,143
Total Risk Management Liabilities	$ 66	$ 30,993	$ -	$ (6,479)	$ 24,580

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

SWEPCo

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (f)	$ -	$ 36,632	$ 2	$ (35,115)	$ 1,519
Cash Flow Hedges:					
Commodity Hedges	-	123	-	-	123
Interest Rate/Foreign Currency Hedges	-	5	-	-	5
Total Risk Management Assets	$ -	$ 36,760	$ 2	$ (35,115)	$ 1,647
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (f)	$ -	$ 39,592	$ -	$ (35,187)	$ 4,405

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(c) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.
(d) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(e) Amounts represent publicly traded equity securities and equity-based mutual funds.
(f) Substantially comprised of power contracts for APCo, I&M and OPCo and coal contracts for PSO and SWEPCo.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2011 and 2010.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2010	$ 5,131	$ 3,108	$ 6,583	$ 1	$ 2
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2,154)	(1,261)	(2,711)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	7,741	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(73)	(47)	(100)	-	-
Purchases, Issuances and Settlements (c)	1,574	847	1,858	-	-
Transfers into Level 3 (d) (f)	2,488	1,531	3,257	-	-
Transfers out of Level 3 (e) (f)	(3,003)	(1,906)	(4,032)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(1,992)	(1,009)	(9,930)	(1)	(2)
Balance as of December 31, 2011	$ 1,971	$ 1,263	$ 2,666	$ -	$ -

Year Ended December 31, 2010	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2009	$ 9,428	$ 4,816	$ 10,345	$ 2	$ 3
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,670	963	2,053	2	2
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	21,314	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-
Purchases, Issuances and Settlements (c)	(7,163)	(4,121)	(8,800)	(1)	(1)
Transfers into Level 3 (d) (f)	1,133	616	1,333	-	-
Transfers out of Level 3 (e) (f)	(10,999)	(6,558)	(13,978)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	11,062	7,392	(5,684)	(2)	(2)
Balance as of December 31, 2010	$ 5,131	$ 3,108	$ 6,583	$ 1	$ 2

Year Ended December 31, 2009	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance as of December 31, 2008	$ 8,009	$ 4,352	$ 10,060	$ (2)	$ (3)
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,324)	(719)	(1,664)	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-	-	9,181	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-	-	-
Purchases, Issuances and Settlements (c)	(5,464)	(2,847)	(6,623)	-	-
Transfers in and/or out of Level 3 (h)	(500)	(263)	(609)	-	-
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	8,707	4,293	-	4	6
Balance as of December 31, 2009	$ 9,428	$ 4,816	$ 10,345	$ 2	$ 3

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Represents existing assets or liabilities that were previously categorized as Level 3.
(f) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(g) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.
(h) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

11. INCOME TAXES

The details of the Registrant Subsidiaries' income taxes before extraordinary item as reported are as follows:

Year Ended December 31, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Income Tax Expense (Credit):					
Current	$ (15,136)	$ (86,471)	$ 96,893	$ 6,904	$ 40,727
Deferred	107,565	141,014	119,184	61,581	16,726
Deferred Investment Tax Credits	(2,569)	(2,783)	(2,380)	(856)	(550)
Income Tax Expense	$ 89,860	$ 51,760	$ 213,697	$ 67,629	$ 56,903

Year Ended December 31, 2010	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Income Tax Expense (Credit):					
Current	$ (66,216)	$ 1,795	$ 11,403	$ (46,528)	$ (16,066)
Deferred	144,413	63,947	292,831	92,695	81,764
Deferred Investment Tax Credits	(3,967)	(2,316)	(2,928)	3,933	(1,484)
Income Tax Expense	$ 74,230	$ 63,426	$ 301,306	$ 50,100	$ 64,214

Year Ended December 31, 2009	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Income Tax Expense (Credit):					
Current	$ (273,084)	$ (187,911)	$ (201,077)	$ (11,338)	$ (6,963)
Deferred	322,626	271,264	514,201	56,029	28,016
Deferred Investment Tax Credits	(4,093)	(2,316)	(2,929)	(770)	(3,542)
Income Tax Expense	$ 45,449	$ 81,037	$ 310,195	$ 43,921	$ 17,511

Shown below for each Registrant Subsidiary is a reconciliation of the difference between the amounts of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

APCo	Years Ended December 31, 2011	2010	2009
		(in thousands)	
Net Income	$ 162,758	$ 136,668	$ 155,814
Income Tax Expense	89,860	74,230	45,449
Pretax Income	$ 252,618	$ 210,898	$ 201,263
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 88,416	$ 73,814	$ 70,442
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	17,923	18,134	11,357
AFUDC	(5,314)	(1,860)	(4,469)
Removal Costs	(4,447)	(6,709)	(6,424)
Investment Tax Credits, Net	(2,569)	(3,967)	(4,093)
State and Local Income Taxes, Net	(35,532)	(7,189)	(15,821)
Medicare Subsidy	4,908	(1,159)	(1,665)
Valuation Allowance	30,541	-	-
Conservation Easement	-	-	(5,250)
Other	(4,066)	3,166	1,372
Income Tax Expense	$ 89,860	$ 74,230	$ 45,449
Effective Income Tax Rate	35.6 %	35.2 %	22.6 %

I&M	Years Ended December 31, 2011	2010	2009
		(in thousands)	
Net Income	$ 149,674	$ 126,091	$ 216,310
Income Tax Expense	51,760	63,426	81,037
Pretax Income	$ 201,434	$ 189,517	$ 297,347
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 70,502	$ 66,331	$ 104,071
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	7,895	11,419	9,550
Nuclear Fuel Disposal Costs	(1,400)	(1,655)	(3,249)
AFUDC	(9,223)	(9,032)	(7,413)
Removal Costs	(5,566)	(3,663)	(5,960)
Investment Tax Credits, Net	(2,783)	(2,316)	(2,316)
State and Local Income Taxes, Net	(1,376)	3,966	(15,059)
Other	(6,289)	(1,624)	1,413
Income Tax Expense	$ 51,760	$ 63,426	$ 81,037
Effective Income Tax Rate	25.7 %	33.5 %	27.3 %

OPCo

	Years Ended December 31, 2011	2010	2009
		(in thousands)	
Net Income	$ 464,993	$ 541,616	$ 580,276
Income Tax Expense	213,697	301,306	310,195
Pretax Income	$ 678,690	$ 842,922	$ 890,471
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 237,542	$ 295,023	$ 311,665
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	6,368	11,443	9,146
Investment Tax Credits, Net	(2,380)	(2,928)	(2,929)
State and Local Income Taxes, Net	(3,222)	906	7,646
Parent Company Loss Benefit	(7,117)	(9,583)	(2,986)
Tax Reserve Adjustments	(1,759)	(620)	(1,713)
Other	(15,735)	7,065	(10,634)
Income Tax Expense	$ 213,697	$ 301,306	$ 310,195
Effective Income Tax Rate	31.5 %	35.7 %	34.8 %

PSO

	Years Ended December 31, 2011	2010	2009
		(in thousands)	
Net Income	$ 124,628	$ 72,787	$ 75,602
Income Tax Expense	67,629	50,100	43,921
Pretax Income	$ 192,257	$ 122,887	$ 119,523
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 67,290	$ 43,010	$ 41,833
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	(165)	(166)	(174)
Investment Tax Credits, Net	(781)	(781)	(770)
State and Local Income Taxes, Net	4,744	10,307	6,025
Other	(3,459)	(2,270)	(2,993)
Income Tax Expense	$ 67,629	$ 50,100	$ 43,921
Effective Income Tax Rate	35.2 %	40.8 %	36.7 %

SWEPCo

	Years Ended December 31, 2011	2010	2009
		(in thousands)	
Net Income	$ 165,126	$ 146,684	$ 117,203
Extraordinary Item, Net of Tax of $2,867 in 2009	-	-	5,325
Income Tax Expense	56,903	64,214	17,511
Pretax Income	$ 222,029	$ 210,898	$ 140,039
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 77,710	$ 73,814	$ 49,014
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	(7)	1,223	1,506
Depletion	(1,506)	(1,506)	(3,150)
AFUDC	(16,962)	(15,856)	(16,243)
Investment Tax Credits, Net	(550)	(1,484)	(3,542)
State and Local Income Taxes, Net	4,004	(637)	647
Parent Company Loss Benefit	(1,948)	-	(4,232)
Other	(3,838)	8,660	(6,489)
Income Tax Expense	$ 56,903	$ 64,214	$ 17,511
Effective Income Tax Rate	25.6 %	30.4 %	12.5 %

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

APCo

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred Tax Assets	$ 591,379	$ 417,393
Deferred Tax Liabilities	(2,341,814)	(2,103,645)
Net Deferred Tax Liabilities	$ (1,750,435)	$ (1,686,252)
Property Related Temporary Differences	$ (1,303,698)	$ (1,151,667)
Amounts Due from Customers for Future Federal Income Taxes	(95,960)	(104,995)
Deferred State Income Taxes	(235,296)	(242,579)
Deferred Income Taxes on Other Comprehensive Loss	31,523	25,859
Deferred Fuel and Purchased Power	(131,137)	(129,671)
Accrued Pensions	45,782	52,406
Regulatory Assets	(194,161)	(179,686)
Postretirement Benefits	61,109	54,484
Net Operating Loss Carryforward	88,721	-
Tax Credit Carryforward	37,850	-
Valuation Allowance	(30,541)	-
All Other, Net	(24,627)	(10,403)
Net Deferred Tax Liabilities	$ (1,750,435)	$ (1,686,252)

I&M

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred Tax Assets	$ 773,679	$ 751,455
Deferred Tax Liabilities	(1,700,182)	(1,530,993)
Net Deferred Tax Liabilities	$ (926,503)	$ (779,538)
Property Related Temporary Differences	$ (305,400)	$ (246,395)
Amounts Due from Customers for Future Federal Income Taxes	(28,551)	(27,932)
Deferred State Income Taxes	(107,497)	(79,522)
Deferred Income Taxes on Other Comprehensive Loss	15,196	11,248
Accrued Nuclear Decommissioning	(435,916)	(394,441)
Postretirement Benefits	51,037	41,727
Accrued Pensions	27,819	36,564
Regulatory Assets	(116,474)	(108,842)
All Other, Net	(26,717)	(11,945)
Net Deferred Tax Liabilities	$ (926,503)	$ (779,538)

OPCo

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred Tax Assets	$ 574,007	$ 434,066
Deferred Tax Liabilities	(2,834,046)	(2,602,853)
Net Deferred Tax Liabilities	$ (2,260,039)	$ (2,168,787)
Property Related Temporary Differences	$ (1,966,581)	$ (1,839,786)
Amounts Due from Customers for Future Federal Income Taxes	(59,699)	(57,519)
Deferred State Income Taxes	(98,093)	(106,759)
Deferred Income Taxes on Other Comprehensive Loss	106,466	97,006
Deferred Fuel and Purchased Power	(194,509)	(182,794)
Postretirement Benefits	74,447	56,224
Accrued Pensions	(30,853)	(1,925)
Regulatory Assets	(205,925)	(149,842)
All Other, Net	114,708	16,608
Net Deferred Tax Liabilities	$ (2,260,039)	$ (2,168,787)

PSO

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred Tax Assets	$ 121,181	$ 90,750
Deferred Tax Liabilities	(840,631)	(751,592)
Net Deferred Tax Liabilities	$ (719,450)	$ (660,842)
Property Related Temporary Differences	$ (626,456)	$ (561,364)
Amounts Due from Customers for Future Federal Income Taxes	(1,023)	(242)
Deferred State Income Taxes	(89,605)	(76,254)
Deferred Income Taxes on Other Comprehensive Loss	(3,849)	(4,574)
Postretirement Benefits	25,607	20,858
DFIT on DSIT	36,018	31,345
Accrued Pensions	12,978	18,389
Regulatory Assets	(77,016)	(74,404)
Net Operating Loss Carryforward	5,247	-
Tax Credit Carryforward	6,872	-
All Other, Net	(8,223)	(14,596)
Net Deferred Tax Liabilities	$ (719,450)	$ (660,842)

SWEPCo

	December 31, 2011	December 31, 2010
	(in thousands)	
Deferred Tax Assets	$ 143,200	$ 104,444
Deferred Tax Liabilities	(800,673)	(713,248)
Net Deferred Tax Liabilities	$ (657,473)	$ (608,804)
Property Related Temporary Differences	$ (588,612)	$ (521,210)
Amounts Due from Customers for Future Federal Income Taxes	(36,289)	(25,800)
Deferred State Income Taxes	(70,211)	(56,315)
Deferred Income Taxes on Other Comprehensive Loss	14,440	6,726
Postretirement Benefits	21,654	17,589
Impairment Loss - Turk Plant	17,150	-
Accrued Pensions	5,861	9,821
Regulatory Assets	(35,349)	(41,956)
All Other, Net	13,883	2,341
Net Deferred Tax Liabilities	$ (657,473)	$ (608,804)

AEP System Tax Allocation Agreement

The Registrant Subsidiaries join in the filing of a consolidated federal income tax return with their affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

The Registrant Subsidiaries are no longer subject to U.S. federal examination for years before 2009. The Registrant Subsidiaries completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not have a material impact on the Registrant Subsidiaries' net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, the Registrant Subsidiaries accrue interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material effect on net income.

The Registrant Subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine their tax returns and the Registrant Subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, the Registrant Subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2000.

Net Income Tax Operating Loss Carryforward

In 2011, APCo and I&M sustained federal net income tax operating losses of $313 million and $123 million, respectively, driven primarily by bonus depreciation, pension plan contributions and other book versus tax temporary differences. APCo, OPCo and PSO also had state net income tax operating loss carryforwards as indicated in the table below. As a result, APCo, I&M, OPCo and PSO accrued deferred federal and/or state and local income tax benefits in 2011 and expect to realize the federal, state and local cash flow benefits in future periods as there was insufficient capacity in prior periods to carry the net operating losses back. Management anticipates future taxable income will be sufficient to realize the net income tax operating loss tax benefits before the federal carryforward expires after 2031.

Company	State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
		(in thousands)	
APCo	Tennessee	$ 13,406	2026
APCo	Virginia	358,469	2031
APCo	West Virginia	468,621	2031
OPCo	West Virginia	41,932	2031
PSO	Oklahoma	134,536	2031

Company	Total Federal Tax Credit Carryforward	Federal Tax Credit Carryforward Subject to Expiration	Total State Tax Credit Carryforward	State Tax Credit Carryforward Subject to Expiration
		(in thousands)		
APCo	$ 36,966	$ 4,487	$ 61,307	$ 28,727
I&M	3,863	2,564	-	-
OPCo	51,703	1,500	-	-
PSO	6,982	214	13,303	-
SWEPCo	5,631	-	-	-

The Registrant Subsidiaries anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. APCo does not anticipate that state taxable income will be sufficient in future periods to realize the tax benefits of all state tax credits before they expire unused and a valuation allowance has been provided accordingly.

Valuation Allowance

Management assesses past results and future operations to estimate and evaluate available positive and negative evidence to evaluate whether sufficient future taxable income will be generated to use existing deferred tax assets. A significant piece of objective negative information evaluated were the net income tax operating losses sustained in 2009 and 2011. On the basis of this evaluation of available positive and negative evidence, as of December 31, 2011, a valuation allowance of $30.5 million for state tax credits, net of federal tax, has been recorded by APCo in order to measure only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are reduced or if objective negative evidence in the form of cumulative losses is no longer present and additional weight may be given to subjective evidence, such as projections for growth.

Uncertain Tax Positions

The Registrant Subsidiaries recognize interest accruals related to uncertain tax positions in interest income or expense as applicable and penalties in Other Operation in accordance with the accounting guidance for "Income Taxes."

The following tables show amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31,					
	2011			2010		
Company	Interest Expense	Interest Income	Reversal of Prior Period Interest Expense	Interest Expense	Interest Income	Reversal of Prior Period Interest Expense
	(in thousands)					
APCo	$ 737	$ 3,229	$ 2,416	$ 2,330	$ -	$ 1,146
I&M	-	2,681	638	-	209	159
OPCo	1,213	5,173	4,019	3,948	-	1,653
PSO	239	344	3,123	455	-	871
SWEPCo	1,382	1,991	2,255	749	-	320

	Year Ended December 31, 2009		
Company	Interest Expense	Interest Income	Reversal of Prior Period Interest Expense
	(in thousands)		
APCo	$ 593	$ -	$ 1,803
I&M	-	4,090	119
OPCo	3,312	-	1,695
PSO	-	721	382
SWEPCo	12	424	428

The following table shows balances for amounts accrued for the receipt of interest:

	December 31,	
Company	2011	2010
	(in thousands)	
APCo	$ 70	$ 934
I&M	759	7,642
OPCo	869	2,790
PSO	134	-
SWEPCo	452	957

The following table shows balances for amounts accrued for the payment of interest and penalties:

	December 31,	
Company	2011	2010
	(in thousands)	
APCo	$ 120	$ 1,274
I&M	145	1,823
OPCo	1,513	6,077
PSO	426	877
SWEPCo	668	1,107

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance at January 1, 2011	$ 13,267	$ 17,871	$ 68,655	$ 9,845	$ 14,410
Increase - Tax Positions Taken During a Prior Period	5,990	9,256	11,330	1,339	14,355
Decrease - Tax Positions Taken During a Prior Period	(2,100)	(8,622)	(20,299)	(1,171)	(2,706)
Increase - Tax Positions Taken During the Current Year	-	-	-	-	-
Decrease - Settlements with Taxing Authorities	(2,587)	(1,424)	(6,935)	(1,178)	(12,997)
Decrease - Lapse of the Applicable Statute of Limitations	(7,259)	(3,010)	(9,186)	(5,250)	(4,031)
Balance at December 31, 2011	$ 7,311	$ 14,071	$ 43,565	$ 3,585	$ 9,031

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance at January 1, 2010	$ 17,292	$ 20,007	$ 65,551	$ 12,216	$ 10,163
Increase - Tax Positions Taken During a Prior Period	4,177	4,964	19,214	151	6,128
Decrease - Tax Positions Taken During a Prior Period	(6,376)	(5,287)	(8,837)	(1,200)	(376)
Decrease - Tax Positions Taken During the Current Year	(1,015)	(1,487)	(1,749)	(517)	(691)
Decrease - Settlements with Taxing Authorities	(811)	(236)	(70)	(265)	(4)
Decrease - Lapse of the Applicable Statute of Limitations	-	(90)	(5,454)	(540)	(810)
Balance at December 31, 2010	$ 13,267	$ 17,871	$ 68,655	$ 9,845	$ 14,410

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Balance at January 1, 2009	$ 20,573	$ 11,815	$ 73,517	$ 13,310	$ 10,252
Increase - Tax Positions Taken During a Prior Period	5,339	8,336	18,038	2,304	4,102
Decrease - Tax Positions Taken During a Prior Period	(8,263)	(14,921)	(24,024)	(2,322)	(3,065)
Increase - Tax Positions Taken During the Current Year	2,471	14,398	890	-	-
Decrease - Tax Positions Taken During the Current Year	-	-	(195)	(533)	(357)
Increase - Settlements with Taxing Authorities	-	645	-	-	-
Decrease - Lapse of the Applicable Statute of Limitations	(2,828)	(266)	(2,675)	(543)	(769)
Balance at December 31, 2009	$ 17,292	$ 20,007	$ 65,551	$ 12,216	$ 10,163

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant Subsidiary was as follows:

Company	2011	2010	2009
		(in thousands)	
APCo	$ 806	$ 1,109	$ 3,777
I&M	654	1,664	1,271
OPCo	21,177	28,749	33,504
PSO	1,882	1,977	2,985
SWEPCo	3,717	2,481	2,278

Federal Tax Legislation – Affecting APCo

Under the Energy Tax Incentives Act of 2005, AEP filed applications with the United States Department of Energy and the IRS in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, AEP entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits. AEP had until July 2010 to meet certain minimum requirements under the agreement with the IRS or the credits would be forfeited. In July 2010, AEP forfeited the allocated tax credits.

Federal Tax Legislation – Affecting APCo, I&M, OPCo, PSO and SWEPCo

The American Recovery and Reinvestment Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to AEP's 2009 federal net operating tax loss that resulted in a 2010 cash flow benefit to the Registrant Subsidiaries as follows:

Company	(in thousands)
APCo	$ 170,466
I&M	78,456
OPCo	141,111
PSO	10,741
SWEPCo	-

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by the Registrant Subsidiaries in March 2010. This reduction did not materially affect the Registrant Subsidiaries' cash flows or financial condition. For the year ended December 31, 2010, the Registrant Subsidiaries reflected a decrease in deferred tax assets, which was partially offset by recording net tax regulatory assets in jurisdictions with regulated operations, resulting in a decrease in net income as follows:

Company	Net Reduction to Deferred Tax Assets	Tax Regulatory Assets, Net	Decrease in Net Income
		(in thousands)	
APCo	$ 9,397	$ 8,831	$ 566
I&M	7,212	6,528	684
OPCo	12,771	6,990	5,781
PSO	3,172	3,172	-
SWEPCo	3,412	3,412	-

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions did not have a material impact on the Registrant Subsidiaries' net income or financial condition but had a favorable impact on cash flows in 2010 as follows:

Company	(in thousands)
APCo	$ 43,379
I&M	49,740
OPCo	124,637
PSO	-
SWEPCo	30,269

In December 2011, the U.S. Treasury Department issued guidance regarding the deduction and capitalization of expenditures related to tangible property. The guidance was in the form of proposed and temporary regulations and generally is effective for tax years beginning in 2012. These regulations did not have an impact on net income or cash flows in 2011. We are still evaluating the impact these regulations will have on future periods.

State Tax Legislation – Affecting APCo, I&M, OPCo, PSO and SWEPCo

Under Ohio House Bill 66, in 2005, AEP reversed deferred state income tax liabilities that are not expected to reverse during the phase-out as follows:

Company	Other Regulatory Liabilities (a)	Regulatory Asset, Net (b)	State Income Tax Expense (c)	Deferred State Income Tax Liabilities (d)
		(in thousands)		
APCo	$ -	$ 10,945	$ 2,769	$ 13,714
I&M	-	5,195	-	5,195
OPCo	56,968	-	-	56,968
PSO	-	-	706	706
SWEPCo	-	582	119	701

(a) The reversal of deferred state income taxes for OPCo was recorded as a regulatory liability pending rate-making treatment in Ohio.
(b) Deferred state income tax adjustments related to those companies in which state income taxes flow through for rate-making purposes reduced the regulatory asset associated with the deferred state income tax liabilities.
(c) These amounts were recorded as a reduction to Income Tax Expense.
(d) Total deferred state income tax liabilities that reversed during 2005 related to Ohio law change.

The Ohio legislation also imposed a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The tax was phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this tax, expenses of approximately $12 million, $11 million and $10 million for OPCo were recorded in 2011, 2010 and 2009, respectively, in Taxes Other Than Income Taxes.

State Tax Legislation – Affecting APCo, I&M and OPCo

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rates from 8.5% to 6.5%. The current 8.5% Indiana corporate income tax rate is scheduled for a 0.5% reduction each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax with a rate of 6%, effective January 1, 2012.

During the third quarter of 2011, the state of West Virginia determined that the State had achieved certain minimum levels of shortfall reserve funds and thus, the West Virginia corporate income tax rate will be reduced to 7.75% in 2012. The enacted provisions will not have a material impact on the Registrant Subsidiaries' net income, cash flows or financial condition.

12. LEASES

Leases of property, plant and equipment are for periods up to 60 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 Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Year Ended December 31, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 13,488	$ 94,317	$ 59,983	$ 6,532	$ 5,990
Amortization of Capital Leases	7,880	8,762	13,118	4,438	12,694
Interest on Capital Leases	1,898	2,115	3,753	1,098	9,651
Total Lease Rental Costs	$ 23,266	$ 105,194	$ 76,854	$ 12,068	$ 28,335

Year Ended December 31, 2010	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 18,034	$ 91,973	$ 62,887	$ 2,649	$ 5,877
Amortization of Capital Leases	7,002	31,178	12,069	3,992	11,742
Interest on Capital Leases	1,598	2,298	3,132	1,057	9,892
Total Lease Rental Costs	$ 26,634	$ 125,449	$ 78,088	$ 7,698	$ 27,511

Year Ended December 31, 2009	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Net Lease Expense on Operating Leases	$ 21,001	$ 94,409	$ 73,458	$ 5,807	$ 8,052
Amortization of Capital Leases	3,480	31,612	7,403	1,485	10,739
Interest on Capital Leases	206	1,937	1,424	85	6,372
Total Lease Rental Costs	$ 24,687	$ 127,958	$ 82,285	$ 7,377	$ 25,163

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the Registrant Subsidiaries' balance sheets. For SWEPCo, current and long-term capital lease obligations are included in Obligations Under Capital Leases on SWEPCo's balance sheets. For all other Registrant Subsidiaries, current capital lease obligations are included in Other Current Liabilities and long-term capital lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

December 31, 2011	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Generation	$ 11,712	$ 16,100	$ 36,689	$ 3,617	$ 20,453
Other Property, Plant and Equipment	25,201	27,712	36,264	16,441	145,273
Total Property, Plant and Equipment	36,913	43,812	72,953	20,058	165,726
Accumulated Amortization	9,886	12,779	22,075	5,196	38,163
Net Property, Plant and Equipment Under Capital Leases	$ 27,027	$ 31,033	$ 50,878	$ 14,862	$ 127,563
Obligations Under Capital Leases:					
Noncurrent Liability	$ 19,293	$ 23,117	$ 40,152	$ 11,101	$ 112,802
Liability Due Within One Year	7,734	7,916	14,096	3,761	15,058
Total Obligations Under Capital Leases	$ 27,027	$ 31,033	$ 54,248	$ 14,862	$ 127,860

December 31, 2010	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Property, Plant and Equipment Under Capital Leases:					
Generation	$ 10,255	$ 19,147	$ 34,220	$ 3,471	$ 15,528
Other Property, Plant and Equipment	29,154	26,922	44,109	19,256	142,210
Total Property, Plant and Equipment	39,409	46,069	78,329	22,727	157,738
Accumulated Amortization	6,678	10,366	18,963	4,338	29,370
Net Property, Plant and Equipment Under Capital Leases	$ 32,731	$ 35,703	$ 59,366	$ 18,389	$ 128,368
Obligations Under Capital Leases:					
Noncurrent Liability	$ 24,617	$ 26,858	$ 46,202	$ 13,838	$ 115,399
Liability Due Within One Year	8,114	8,845	16,060	4,551	13,265
Total Obligations Under Capital Leases	$ 32,731	$ 35,703	$ 62,262	$ 18,389	$ 128,664

Future minimum lease payments consisted of the following at December 31, 2011:

Capital Leases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2012	$ 8,933	$ 9,246	$ 13,260	$ 4,484	$ 23,626
2013	6,443	5,519	12,613	3,938	22,496
2014	4,006	4,345	9,176	2,867	20,979
2015	3,276	3,025	6,075	1,633	18,947
2016	2,794	2,568	5,512	1,356	16,104
Later Years	5,430	13,998	19,898	2,909	69,586
Total Future Minimum Lease Payments	30,882	38,701	66,534	17,187	171,738
Less Estimated Interest Element	3,855	7,668	12,286	2,325	43,879
Estimated Present Value of Future Minimum Lease Payments	$ 27,027	$ 31,033	$ 54,248	$ 14,862	$ 127,859

Noncancelable Operating Leases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2012	$ 14,338	$ 99,114	$ 59,914	$ 2,563	$ 5,988
2013	13,683	98,625	55,820	1,969	5,261
2014	12,370	97,825	53,837	1,438	3,629
2015	9,443	94,694	50,881	1,107	3,020
2016	8,699	89,368	44,592	818	2,375
Later Years	53,149	506,585	106,540	1,769	10,882
Total Future Minimum Lease Payments	$ 111,682	$ 986,211	$ 371,584	$ 9,664	$ 31,155

Master Lease Agreements

The Registrant Subsidiaries lease certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. In January 2011, $5 million of previously leased assets not included in the 2010 refinancing were purchased.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 78% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 78% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrant Subsidiaries are committed to pay the difference between the actual fair value and the residual value guarantee. At December 31, 2011, the maximum potential loss by Registrant Subsidiary for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is as follows:

Company	Maximum Potential Loss
	(in thousands)
APCo	$ 2,055
I&M	2,139
OPCo	2,700
PSO	818
SWEPCo	2,092

Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Rockport Lease

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). The 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 equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. 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. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. I&M's future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2011 are as follows:

Future Minimum Lease Payments	I&M
	(in millions)
2012	$ 74
2013	74
2014	74
2015	74
2016	74
Later Years	443
Total Future Minimum Lease Payments	$ 813

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $16 million for I&M and $18 million for SWEPCo for the remaining railcars as of December 31, 2011. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million and SWEPCo's is approximately $13 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. In addition to the 2009 transactions, Sabine has one additional $53 million dragline completed in 2008 that was financed under a capital lease. These capital lease assets are included in Other Property, Plant and Equipment on SWEPCo's December 31, 2011 and 2010 balance sheets. The short-term and long-term capital lease obligations are included in Obligations Under Capital Leases on SWEPCo's December 31, 2011 and 2010 balance sheets. The future payment obligations are included in SWEPCo's future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $383 thousand are included in I&M's future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on I&M's December 31, 2011 and 2010 balance sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2011 are $383 thousand for 2012, based on estimated fuel burn.

13. FINANCING ACTIVITIES

Preferred Stock

In December 2011, the Registrant Subsidiaries redeemed all of their outstanding preferred stock, resulting in a loss, which is included in Preferred Stock Dividend Requirements Including Capital Stock Expense on the statements of income. The redeemed shares are no longer outstanding and represent only the right to receive the applicable redemption price, to the extent the shares have not yet been presented for payment. The par value of preferred stock redeemed and the loss recorded by the Registrant Subsidiaries was as follows:

Company	Par Value of Stock Redeemed	Loss on Redemption
	(in thousands)	
APCo	$ 17,736	$ 1,013
I&M	8,072	314
OPCo	16,613	488
PSO	4,882	254
SWEPCo	4,694	369

Company	Series	Number of Shares Redeemed for the Years Ended December 31, 2011	2010	2009
APCo	4.50 %	177,465	53	2
I&M	4.12 %	11,055	-	-
I&M	4.125 %	55,257	44	34
I&M	4.56 %	14,412	-	-
OPCo	4.08 %	14,495	100	-
OPCo	4.20 %	22,824	-	-
OPCo	4.40 %	31,482	-	-
OPCo	4.50 %	97,357	6	10
PSO	4.00 %	44,508	-	40
PSO	4.24 %	4,310	3,759	-
SWEPCo	4.28 %	7,386	-	-
SWEPCo	4.65 %	1,907	-	-
SWEPCo	5.00 %	37,665	8	-

Long-term Debt

There are certain limitations on establishing liens against the Registrant Subsidiaries' assets under their respective indentures. None of the long-term debt obligations of the Registrant Subsidiaries have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2011 and 2010:

Company	Maturity	Weighted Average Interest Rate at December 31, 2011	Interest Rate Ranges at December 31, 2011	2010	Outstanding at December 31, 2011	2010
Senior Unsecured Notes					(in thousands)	
APCo	2011-2038	5.86%	3.40%-7.95%	3.40%-7.95%	$ 3,141,843	$ 3,042,060
I&M	2012-2037	6.25%	5.05%-7.00%	5.05%-7.00%	1,270,599	1,270,116
OPCo	2012-2035	5.61%	0.955%-6.60%	0.702%-6.60%	3,291,823	3,291,027
PSO	2011-2037	5.52%	4.40%-6.625%	4.70%-6.625%	896,023	922,576
SWEPCo	2015-2040	5.92%	4.90%-6.45%	4.90%-6.45%	1,548,437	1,548,185
Pollution Control Bonds (a)						
APCo	2011-2038 (b)	2.27%	0.07%-6.05%	0.29%-6.05%	582,000	516,650
I&M	2011-2025 (b)	4.02%	0.06%-6.25%	0.33%-6.25%	266,494	266,456
OPCo	2011-2038 (b)	3.81%	0.07%-5.80%	0.30%-5.80%	562,325	677,325
PSO	2014-2020	5.03%	4.45%-5.25%	4.45%-5.25%	46,360	46,360
SWEPCo	2011-2018	4.28%	3.25%-4.95%	3.25%-4.95%	135,200	176,335
Notes Payable - Affiliated						
OPCo	2015	5.25%	5.25%	5.25%	200,000	200,000
Notes Payable - Nonaffiliated						
I&M	2013-2016	3.01%	2.029%-5.44%	2.07%-5.44%	234,590	202,753
SWEPCo	2012-2024	6.66%	6.37%-7.03%	6.37%-7.03%	45,000	45,000
Spent Nuclear Fuel Obligation (c)						
I&M					265,065	264,901
Other Long-term Debt						
APCo	2026	13.718%	13.718%	13.718%	2,408	2,431
I&M	2025	6.00%	6.00%	-	20,927	-
PSO	2027	3.00%	3.00%	3.00%	4,981	2,250

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

(b) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year – Nonaffiliated on the balance sheets.

(c) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 5).

Long-term debt outstanding at December 31, 2011 is payable as follows:

	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
2012	$ 594,525	$ 279,075	$ 244,500	$ 311	$ 20,000
2013	70,029	78,977	806,000	479	-
2014	100,033	322,972	403,580	34,193	-
2015	500,037	132,813	286,000	508	303,500
2016	43	2,662	350,000	150,523	-
After 2016	2,469,741	1,246,083	1,972,245	765,327	1,406,700
Principal Amount	3,734,408	2,062,582	4,062,325	951,341	1,730,200
Unamortized Discount, Net	(8,157)	(4,907)	(8,177)	(3,977)	(1,563)
Total Long-term Debt Outstanding	$ 3,726,251	$ 2,057,675	$ 4,054,148	$ 947,364	$ 1,728,637

In January and February 2012, I&M retired $2 million and $12 million, respectively, of Notes Payable related to DCC Fuel.

In February 2012, SWEPCo issued $275 million of 3.55% Senior Unsecured Notes due in 2022 and $65 million of 4.58% Notes Payable due in 2032.

In February 2012, APCo retired $30 million of 6.05% Pollution Control Bonds due in 2024 and $19.5 million of 5% Pollution Control Bonds due in 2021. As of December 31, 2011, these bonds were classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on APCo's balance sheet.

As of December 31, 2011, trustees held, on behalf of OPCo, $418 million of its reacquired Pollution Control Bonds.

Dividend Restrictions

The Registrant Subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the Registrant Subsidiaries to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits each of the Registrant Subsidiaries from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. As applicable, the Registrant Subsidiaries understand "capital account" to mean the value of the common stock.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants. Because of their respective ownership of such plants, this reserve applies to APCo, I&M and OPCo.

None of these restrictions limit the ability of the Registrant Subsidiaries to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, APCo, I&M and OPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. At December 31, 2011, $59 million of APCo's retained earnings and none of I&M's or OPCo's retained earnings have restrictions related to the payment of dividends to Parent.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of December 31, 2011 and 2010 is included in Advances to/from Affiliates on each of the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and their corresponding authorized borrowing limits for the years ended December 31, 2011 and 2010 are described in the following tables:

Year Ended December 31, 2011:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Net Loans (Borrowings) to/from Utility Money Pool as of December 31, 2011	Authorized Short-term Borrowing Limit
			(in thousands)			
APCo	$ 217,876	$ 393,811	$ 117,378	$ 96,186	$ (176,240)	$ 600,000
I&M	57,352	219,386	23,793	56,999	95,714	500,000
OPCo	46,761	452,187	31,365	225,728	219,458	600,000
PSO	96,034	255,611	41,971	88,805	39,876	300,000
SWEPCo	136,752	105,184	47,232	38,798	(132,473)	350,000

Year Ended December 31, 2010:

Company	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31, 2010	Authorized Short-term Borrowing Limit
			(in thousands)			
APCo	$ 438,039	$ -	$ 227,002	$ -	$ (128,331)	$ 600,000
I&M	42,769	223,111	17,972	107,123	(42,769)	500,000
OPCo	-	655,118	-	304,747	154,702	950,000
PSO	107,320	74,751	45,287	31,211	(91,382)	300,000
SWEPCo	78,616	274,958	39,458	184,126	86,222	350,000

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool were as follows:

	Years Ended December 31, 2011	2010	2009
Maximum Interest Rate	0.56 %	0.55 %	2.28 %
Minimum Interest Rate	0.06 %	0.09 %	0.15 %

The average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2011, 2010 and 2009 are summarized for all Registrant Subsidiaries in the following table:

Company	Average Interest Rate for Funds Borrowed from Utility Money Pool for Years Ended December 31, 2011	2010	2009	Average Interest Rate for Funds Loaned to Utility Money Pool for Years Ended December 31, 2011	2010	2009
APCo	0.42 %	0.26 %	0.89 %	0.32 %	- %	- %
I&M	0.39 %	0.43 %	1.46 %	0.38 %	0.24 %	0.26 %
OPCo	0.45 %	- %	1.19 %	0.35 %	0.22 %	0.21 %
PSO	0.41 %	0.31 %	2.01 %	0.32 %	0.17 %	0.56 %
SWEPCo	0.40 %	0.19 %	1.66 %	0.33 %	0.27 %	0.52 %

Interest expense related to the Utility Money Pool is included in Interest Expense on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries incurred interest expense for amounts borrowed from the Utility Money Pool as follows:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
APCo	$ 198	$ 611	$ 1,887
I&M	20	17	924
OPCo	12	16	3,156
PSO	85	102	86
SWEPCo	174	11	68

Interest income related to the Utility Money Pool is included in Interest Income on each of the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries earned interest income for amounts advanced to the Utility Money Pool as follows:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
APCo	$ 313	$ 9	$ -
I&M	226	219	129
OPCo	820	708	228
PSO	250	19	322
SWEPCo	32	438	278

Short-term Debt

The Registrant Subsidiaries' outstanding short-term debt was as follows:

		December 31, 2011		2010	
Company	Type of Debt	Outstanding Amount	Interest Rate (a)	Outstanding Amount	Interest Rate (a)
		(in thousands)		(in thousands)	
SWEPCo	Line of Credit – Sabine	$ 17,016	1.79 %	$ 6,217	2.15 %

(a) Weighted average rate.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation on the Registrant Subsidiaries' income statements. The Registrant Subsidiaries manage and service their customer accounts receivable sold.

In July 2011, AEP Credit renewed its receivables securitization agreement. The agreement provides commitments of $750 million from bank conduits to finance receivables from AEP Credit with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million, with the seasonal increase to $425 million for the months of July, August and September, expires in June 2012 and the remaining commitment of $375 million expires in June 2014.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement for each Registrant Subsidiary as of December 31, 2011 and 2010 was as follows:

Company	December 31, 2011	December 31, 2010
	(in thousands)	
APCo	$ 121,605	$ 145,515
I&M	121,597	123,366
OPCo	346,695	344,698
PSO	123,172	121,679
SWEPCo	140,440	135,092

The fees paid by the Registrant Subsidiaries to AEP Credit for customer accounts receivable sold were:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
APCo	$ 9,612	$ 9,194	$ 5,132
I&M	6,168	6,770	6,191
OPCo	18,851	20,630	19,994
PSO	6,363	5,406	6,954
SWEPCo	5,672	5,688	6,171

The Registrant Subsidiaries' proceeds on the sale of receivables to AEP Credit were:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
APCo	$ 1,248,253	$ 1,418,487	$ 1,258,860
I&M	1,323,068	1,283,955	1,228,502
OPCo	3,461,758	3,495,609	3,201,767
PSO	1,299,190	1,196,586	1,028,770
SWEPCo	1,495,397	1,402,525	1,300,393

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 11 in addition to "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 13.

AEP Power Pool

APCo, I&M, KPCo, OPCo and AEPSC are parties to the Interconnection Agreement, which defines the sharing of costs and benefits associated with the respective generating plants. This sharing is based upon each AEP utility subsidiary's MLR and is calculated monthly on the basis of each AEP utility subsidiary's maximum peak demand in relation to the sum of the maximum peak demands of all four AEP utility subsidiaries during the preceding 12 months. In addition, APCo, I&M, KPCo and OPCo are parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Based upon the PUCO's January 2012 approval of OPCo's corporate separation plan, applications were filed in February 2012 with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo and transfer OPCo's generation assets to APCo, KPCo and a nonregulated AEP subsidiary. The Ohio corporate separation plan was subsequently rejected on rehearing in February 2012. Management is in the process of withdrawing the applications and intends to file new FERC and PUCO applications related to corporate separation.

Power, gas and risk management activities are conducted by AEPSC and profits and losses are allocated under the SIA to AEP Power Pool members, PSO and SWEPCo. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and OTC options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, AEPSC enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. The CSW Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

System Integration Agreement (SIA)

The SIA provides for the integration and coordination of AEP East companies' and AEP West companies' zones. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). The SIA is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any Registrant Subsidiary is primarily sold to customers by such Registrant Subsidiary at rates approved (other than in Ohio) by the public utility commission in the jurisdiction of sale. In Ohio, such rates are based on a statutory formula as that jurisdiction transitions to the use of market rates for generation.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of any Registrant Subsidiary is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues and Purchases

The following tables show the revenues derived from sales to the pools, direct sales to affiliates, net transmission agreement sales, natural gas contracts with AEPES and other revenues for the years ended December 31, 2011, 2010 and 2009:

Related Party Revenues	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2011					
Sales to AEP Power Pool	$ 186,788	$ 308,336	$ 823,703	$ -	$ -
Direct Sales to East Affiliates	126,737	-	115,120	124	3,535
Direct Sales to West Affiliates	1,492	908	1,936	10,624	43,714
Direct Sales to AEPEP	-	-	-	-	(637)
Transmission Agreement and Transmission Coordination Agreement Sales	2,348	9,379	3,375	111	8,962
Natural Gas Contracts with AEPES	154	92	196	3	4
Other Revenues	42,283	1,469	33,669	3,330	2,037
Total Affiliated Revenues	$ 359,802	$ 320,184	$ 977,999	$ 14,192	$ 57,615

Related Party Revenues	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2010					
Sales to AEP Power Pool	$ 158,873	$ 327,992	$ 839,441	$ -	$ -
Direct Sales to East Affiliates	123,832	-	115,406	1,210	1,248
Direct Sales to West Affiliates	3,471	1,931	4,125	19,629	39,851
Direct Sales to AEPEP	-	-	-	-	(286)
Direct Sales to Transmission Companies	44	1,848	236	30	1
Natural Gas Contracts with AEPES	(2,171)	(1,087)	(2,330)	2	3
Other Revenues	32,158	267	34,407	2,657	11,053
Total Affiliated Revenues	$ 316,207	$ 330,951	$ 991,285	$ 23,528	$ 51,870

Related Party Revenues	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2009					
Sales to AEP Power Pool	$ 130,331	$ 198,579	$ 813,692	$ -	$ -
Direct Sales to East Affiliates	123,549	-	84,078	3,136	1,220
Direct Sales to West Affiliates	2,255	1,154	2,553	39,197	16,434
Direct Sales to AEPEP	-	-	-	-	(659)
Natural Gas Contracts with AEPES	(8,340)	(4,637)	(11,008)	(328)	(387)
Other Revenues	15,594	1,055	31,774	3,751	12,710
Total Affiliated Revenues	$ 263,389	$ 196,151	$ 921,089	$ 45,756	$ 29,318

The following tables show the purchased power expense incurred for purchases from the pools and affiliates for the years ended December 31, 2011, 2010 and 2009:

Related Party Purchases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2011					
Purchases from AEP Power Pool	$ 818,943	$ 124,598	$ 326,871	$ -	$ -
Direct Purchases from East Affiliates	-	-	-	6,378	1,184
Direct Purchases from West Affiliates	239	147	312	43,714	10,624
Purchases from AEGCo	-	228,739	185,741	-	-
Gas Purchases from AEPES	-	-	2,689	-	-
Total Purchases	$ 819,182	$ 353,484	$ 515,613	$ 50,092	$ 11,808

Related Party Purchases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2010					
Purchases from AEP Power Pool	$ 916,791	$ 91,129	$ 268,964	$ -	$ -
Direct Purchases from East Affiliates	-	-	-	6,162	4,078
Direct Purchases from West Affiliates	825	466	996	39,851	19,629
Purchases from AEGCo	-	235,740	113,801	-	-
Gas Purchases from AEPES	-	-	2,857	-	-
Total Purchases	$ 917,616	$ 327,335	$ 386,618	$ 46,013	$ 23,707

Related Party Purchases	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)		
Year Ended December 31, 2009					
Purchases from AEP Power Pool	$ 801,624	$ 99,159	$ 209,606	$ -	$ -
Direct Purchases from East Affiliates	-	-	-	2,896	3,515
Direct Purchases from West Affiliates	1,492	777	1,789	16,435	39,197
Direct Purchases from AEGCo	-	237,372	75,469	-	-
Gas Purchases from AEPES	-	-	1,251	-	-
Total Purchases	$ 803,116	$ 337,308	$ 288,115	$ 19,331	$ 42,712

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

System Transmission Integration Agreement

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East companies' and AEP West companies' zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The System Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, I&M, KPCo and OPCo are parties to the TA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's MLR. The FERC approved a new TA effective November 2010. The impacts of the new TA will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

The following table shows the net charges recorded by the Registrant Subsidiaries, party to the new TA, for the year ended December 31, 2011:

Company		Year Ended December 31, 2011
		(in thousands)
APCo	$	4,608
I&M		1,538
OPCo		17,186

The charges shown above are recorded in Other Operation expense on the statements of income.

The following table shows the net charges (credits) allocated among the Registrant Subsidiaries, party to the original TA, for the years ended December 31, 2010 and 2009:

Company		Years Ended December 31, 2010		2009
		(in thousands)		
APCo	$	(16,079)	$	(12,535)
I&M		(25,188)		(38,400)
OPCo		49,281		59,770

The net charges (credits) shown above are recorded in Other Operation expense on the statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, revised 1999 and 2011, as restated and amended, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. Effective May 2011, TNC is no longer a party to the agreement. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such a tariff.

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo).

The following table shows the net (revenues) expenses allocated among parties to the TCA pursuant to the SPP OATT protocols as described above for the years ended December 31, 2011, 2010 and 2009:

Company		Years Ended December 31, 2011		2010		2009
				(in thousands)		
PSO	$	9,000	$	10,600	$	11,100
SWEPCo		(9,000)		(10,500)		(11,100)

The net (revenues) expenses shown above are recorded in Sales to AEP Affiliates on SWEPCo's statements of income and Other Operation expense on PSO's statements of income.

Assignment from SWEPCo to AEPEP

In March 2008, SWEPCo assigned its portion of a 20-year Purchase Power Agreement (PPA) to AEPEP. In addition to the PPA assignment, an intercompany agreement was executed between AEPEP and SWEPCo to provide SWEPCo with future margins related to its share. SWEPCo also retained the rights to the Renewable Energy Credit Offsets from the PPA. The PPA and intercompany agreements are effective through 2019. SWEPCo recorded losses of $637 thousand, $286 thousand and $659 thousand from AEPEP in Sales to AEP Affiliates on the 2011, 2010 and 2009 statements of income, respectively.

ERCOT Contracts Transferred to AEPEP

Effective January 1, 2007, PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEPEP and entered into intercompany financial and physical purchase and sale agreements with AEPEP. This was done to lock in PSO and SWEPCo's margins on ERCOT trading and marketing contracts and to transfer the future associated commodity price and credit risk to AEPEP. The contracts ended in December 2009.

PSO and SWEPCo have historically presented third party ERCOT trading and marketing activity on a net basis in Revenues - Electric Generation, Transmission and Distribution. The applicable ERCOT third party trading and marketing contracts that were not transferred to AEPEP will remain until maturity on the balance sheets and will be presented on a net basis in Sales to AEP Affiliates on the statements of income.

The following tables indicate the sales to AEPEP and the amounts reclassified from third party to affiliates:

	Year Ended December 31, 2009		
Company	Net Settlement with AEPEP	Third Party Amounts Reclassified to Affiliate	Net Amount Included in Sales to AEP Affiliates
		(in thousands)	
PSO	$ (3,871)	$ 4,318	$ 447
SWEPCo	(4,569)	5,098	529

OPCo Transfer of Property

In May 2009, OPCo transferred a parking garage to AEP through a dividend. AEP then transferred the property to AEPSC through a capital contribution. The transfers were effective May 2009 and were recorded at net book value of $8 million.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. The related purchases of gas managed by AEPES were as follows:

	Years Ended December 31,		
Company	2011	2010	2009
		(in thousands)	
APCo	$ 866	$ 940	$ 431
I&M	523	547	224
OPCo	1,117	1,175	508

These purchases are reflected in Purchased Electricity for Resale on the statements of income.

Unit Power Agreements (UPA)

Lawrenceburg UPA between OPCo and AEGCo

In March 2007, OPCo and AEGCo entered into a 10-year UPA for the entire output from the Lawrenceburg Generating Station effective with AEGCo's purchase of the plant in May 2007. The UPA has an option for an additional 2-year period. I&M operates the plant under an agreement with AEGCo. Under the UPA, OPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant is operating. The fuel and operation and maintenance payments are based on actual costs incurred. All expenses are trued up periodically.

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

Cook Coal Terminal

Cook Coal Terminal, a division of OPCo, performs coal transloading services at cost for APCo and I&M. OPCo included revenues for these services in Other Revenues – Affiliated and expenses in Other Operation expense on the statements of income. The coal transloading revenues in 2011, 2010 and 2009 were as follows:

	Years Ended December 31,		
Company	**2011**	**2010**	**2009**
		(in thousands)	
APCo	$ 31	$ -	$ 916
I&M	21,852	17,208	18,908

APCo and I&M recorded the cost of transloading services in Fuel on the balance sheets.

Cook Coal Terminal also performs railcar maintenance services at cost for APCo, I&M, PSO and SWEPCo. OPCo included revenues for these services in Sales to AEP Affiliates and expenses in Other Operation expense on the statements of income. The railcar maintenance revenues in 2011, 2010 and 2009 were as follows:

	Years Ended December 31,		
Company	**2011**	**2010**	**2009**
		(in thousands)	
APCo	$ 9	$ 7	$ 98
I&M	3,012	1,870	2,045
PSO	542	522	510
SWEPCo	2,348	1,044	914

APCo, I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

In addition, Cook Coal Terminal provides railcar maintenance services for OVEC. OPCo recorded revenue in Other Revenues – Nonaffiliated on the statements of income in the amount of $1 million, for each year in 2011, 2010 and 2009. OVEC is 43.47% owned by AEP (includes OPCo's 4.3% ownership of OVEC).

SWEPCo Railcar Facility

SWEPCo operates a railcar maintenance facility in Alliance, Nebraska. The facility performs maintenance on its own railcars as well as railcars belonging to I&M, PSO and third parties. SWEPCo billed I&M $2.9 million and $1.8 million for railcar services provided in 2011 and 2010, respectively, and billed PSO $287 thousand and $655 thousand in 2011 and 2010, respectively. These billings, for SWEPCo, and costs, for I&M and PSO, are recorded in Fuel on the balance sheets.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expense or other operation expense. The amount of affiliated revenues and affiliated expenses were:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
I&M – Revenue	$ 105,373	$ 105,811	$ 94,921
AEGCo – Expense	15,460	12,548	13,167
APCo – Expense	27,455	28,241	29,442
KPCo – Expense	122	133	112
OPCo – Expense	36,980	44,160	38,039
AEP River Operations LLC – Expense (Nonutility Subsidiary of AEP)	25,356	20,729	14,161

In addition, I&M provided transloading services to OVEC. I&M recorded revenues of $116 thousand, $112 thousand and $135 thousand for 2011, 2010 and 2009, respectively, in Other Revenues – Nonaffiliated on the statements of income.

Services Provided by AEP River Operations LLC

AEP River Operations LLC provides services for barge towing, chartering and general and administrative expenses to I&M. The costs are recorded by I&M as Other Operation expense. For the years ended December 31, 2011, 2010 and 2009, I&M recorded expenses of $24 million, $28 million and $24 million, respectively, for these activities.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet, then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
AEGCo	$ 102	$ 180	$ 31
I&M	2,157	2,112	2,818
KGPCo	-	-	5
KPCo	298	368	358
OPCo	3,684	3,665	4,137
PSO	53	412	848
SWEPCo	946	560	966

In addition, APCo billed OVEC and IKEC a total of $569 thousand, $541 thousand and $202 thousand for the years ended December 31, 2011, 2010 and 2009, respectively.

Affiliate Coal Purchases

In 2008, OPCo entered into contracts to sell excess coal purchases to certain AEP subsidiaries through 2010. These sales (purchases) are reflected in Sales to AEP Affiliates on the statements of income. The following table shows the realized and unrealized amounts recorded for the years ended December 31, 2010 and 2009:

Company	Years Ended December 31, 2010	2009
	(in thousands)	
APCo	$ (2,830)	$ (1,573)
I&M	(1,383)	(813)
KPCo	(837)	(340)
OPCo	7,372	4,239
PSO	(796)	(585)
SWEPCo	(1,526)	(928)

Affiliate Railcar Agreement

Certain AEP subsidiaries have an agreement providing for the use of each other's leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. The AEP subsidiaries recorded these costs or reimbursements as costs or reduction of costs, respectively, in Fuel on the balance sheets and such costs are recoverable from customers. The following tables show the net effect of the railcar agreement on the balance sheets:

December 31, 2011
Billing Company

Billed Company	APCo	I&M	OPCo	PSO	SWEPCo	Total
			(in thousands)			
APCo	$ -	$ -	$ 1,373	$ -	$ -	$ 1,373
I&M	91	-	1,190	80	787	2,148
KPCo	289	-	355	-	-	644
OPCo	840	170	-	8	66	1,084
PSO	289	842	234	-	382	1,747
SWEPCo	12	2,662	605	91	-	3,370
Total	$ 1,521	$ 3,674	$ 3,757	$ 179	$ 1,235	$ 10,366

December 31, 2010
Billing Company

Billed Company	APCo	I&M	OPCo	PSO	SWEPCo	Total
			(in thousands)			
APCo	$ -	$ -	$ 1,195	$ 1	$ (1)	$ 1,195
I&M	142	-	1,536	123	502	2,303
KPCo	399	-	245	-	-	644
OPCo	919	418	-	21	106	1,464
PSO	177	921	191	-	493	1,782
SWEPCo	328	2,162	594	110	-	3,194
Total	$ 1,965	$ 3,501	$ 3,761	$ 255	$ 1,100	$ 10,582

Purchased Power from OVEC

The amounts of power purchased by the Registrant Subsidiaries from OVEC for the years ended December 31, 2011, 2010 and 2009 were:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
APCo	$ 114,311	$ 105,307	$ 103,369
I&M	57,192	52,687	51,710
OPCo	145,207	133,776	131,318

The amounts shown above are recoverable from customers and are included in Purchased Electricity for Resale on the statements of income.

AEP Power Pool Purchases from OVEC

In 2011, the AEP Power Pool purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Purchased Electricity for Resale on the statements of income. The following table shows the amounts recorded for the year ended December 31, 2011:

Company	Year Ended December 31, 2011
	(in thousands)
APCo	$ 21,110
I&M	12,942
OPCo	27,566

In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales and retail sales through June 2010. Purchases serving off-system sales are reported net as a reduction in Electric Generation, Transmission and Distribution revenues and purchases serving retail sales are reported in Purchased Electricity for Resale on the statements of income. The following table shows the amounts recorded for the year ended December 31, 2010:

	Year Ended December 31, 2010	
Company	Reported in Revenues	Reported in Expenses
	(in thousands)	
APCo	$ 6,631	$ 3,635
I&M	3,721	1,980
OPCo	7,937	4,231

SWEPCo Transactions with Oxbow Lignite Company

Oxbow Lignite Company, LLC (OLC) is jointly-owned by SWEPCo and CLECO, each owning 50%. As joint-owners, SWEPCo and CLECO have equal representation in OLC regarding ownership, liability, profit and distributions. OLC has surface lease and lignite and coal lease agreements which provide equal rights to each owner to mine the reserves and equal liability for the depletion costs. DHLC is the exclusive miner of OLC's reserves and 100% of the lignite mined is sold to SWEPCo and CLECO. SWEPCo paid OLC $890 thousand and $465 thousand for land leases, lignite leases and administrative services in 2011 and 2010, respectively. SWEPCo recorded these costs in Fuel on the balance sheets. See "Oxbow Lignite Company and Red River Mining Company" section of Note 6 for additional information regarding the purchase of OLC.

Sales and Purchases of Property – Transmission Companies

In 2009, AEP Transmission Company, LLC (AEP Transco) formed seven wholly-owned transmission companies. AEP Transco is the holding company for the seven transmission companies. These seven companies (collectively Transcos) consist of: AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc. (IMTCo), AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc. (OHTCo), AEP West Virginia Transmission Company, Inc., AEP Oklahoma Transmission Company, Inc. (OKTCo) and AEP Southwestern Transmission Company, Inc. (SWTCo).

In 2010, certain AEP subsidiaries began selling and purchasing transmission property to/from certain Transcos. There were no gains or losses recorded on the transactions. The following table shows the sales, that were recorded at net book value, for the years ended December 31, 2011 and 2010:

Companies	Years Ended December 31, 2011	2010
	(in thousands)	
IMTCo to I&M	$ 1,156	$ -
OPCo to OHTCo	8,723	-
PSO to OKTCo	1	1,543
SWTCo to SWEPCo	27	-

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2011, 2010 and 2009 as shown in the following tables:

Companies	Year Ended December 31, 2011 (in thousands)
APCo to I&M	$ 277
APCo to KPCo	555
APCo to OPCo	523
OPCo to APCo	438
OPCo to I&M	848
PSO to SWEPCo	271

Companies	Year Ended December 31, 2010 (in thousands)
AEGCo to APCo	$ 332
AEGCo to OPCo	190
APCo to I&M	1,090
APCo to KPCo	209
I&M to APCo	444
I&M to OPCo	485
I&M to SWEPCo	218
OPCo to APCo	3,011
OPCo to I&M	2,435
OPCo to KPCo	960
SWEPCo to PSO	3,680
TCC to SWEPCo	360

Companies	Year Ended December 31, 2009 (in thousands)
APCo to I&M	$ 155
I&M to APCo	4,004
I&M to OPCo	6,378
OPCo to APCo	908
OPCo to I&M	6,026
OPCo to TCC	526
PSO to SWEPCo	118
TCC to APCo	426
TCC to SWEPCo	684

In addition, certain AEP subsidiaries had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2011, 2010 and 2009 as shown in the following tables:

Year Ended December 31, 2011

						Purchaser					
Seller	APCo	I&M	KGPCo	KPCo	OPCo	PSO	SWEPCo	TCC	TNC	WPCo	Total
						(in thousands)					
APCo	$ -	$ 38	$ 1,106	$ 119	$ 731	$ 3	$ 293	$ 333	$ -	$ -	$ 2,623
I&M	61	-	-	-	324	10	15	14	2	15	441
KGPCo	903	-	-	3	-	-	-	-	-	-	906
KPCo	289	10	1	-	91	-	8	2	3	-	404
OPCo	54	1,338	-	44	-	25	96	90	1	456	2,104
PSO	3	-	-	-	13	-	150	2	2	-	170
SWEPCo	14	-	-	-	63	402	-	145	26	-	650
TCC	550	11	-	240	568	19	1,410	-	2,106	11	4,915
TNC	-	-	-	12	539	16	723	2,021	-	-	3,311
WPCo	-	-	-	7	193	-	-	-	-	-	200
Total	$ 1,874	$ 1,397	$ 1,107	$ 425	$ 2,522	$ 475	$ 2,695	$ 2,607	$ 2,140	$ 482	$ 15,724

Year Ended December 31, 2010

						Purchaser					
Seller	APCo	I&M	KGPCo	KPCo	OPCo	PSO	SWEPCo	TCC	TNC	WPCo	Total
						(in thousands)					
APCo	$ -	$ 112	$ 225	$ 139	$ 137	$ 61	$ 31	$ -	$ -	$ -	$ 705
I&M	138	-	-	7	356	116	1	-	63	14	695
KGPCo	154	-	-	-	-	-	-	-	-	-	154
KPCo	364	6	23	-	92	-	2	-	-	-	487
OPCo	211	432	1	139	-	79	1,104	165	10	372	2,513
PSO	-	-	-	-	44	-	560	6	3	-	613
SWEPCo	48	4	-	3	214	1,203	-	70	11	-	1,553
TCC	22	38	-	-	23	6	266	-	966	-	1,321
TNC	8	-	-	-	-	1	70	642	-	4	725
WPCo	-	-	-	-	111	-	-	-	-	-	111
Total	$ 945	$ 592	$ 249	$ 288	$ 977	$ 1,466	$ 2,034	$ 883	$ 1,053	$ 390	$ 8,877

Year Ended December 31, 2009

						Purchaser					
Seller	APCo	I&M	KGPCo	KPCo	OPCo	PSO	SWEPCo	TCC	TNC	WPCo	Total
						(in thousands)					
APCo	$ -	$ 87	$ 305	$ 161	$ 147	$ -	$ 19	$ 44	$ -	$ -	$ 763
I&M	39	-	-	50	403	119	65	37	75	17	805
KGPCo	213	-	-	-	-	-	-	-	-	-	213
KPCo	505	64	7	-	156	3	8	-	-	1	744
OPCo	402	323	-	87	-	99	91	1	44	467	1,514
PSO	23	7	-	-	43	-	607	26	1	-	707
SWEPCo	38	21	-	26	85	1,360	-	162	28	-	1,720
TCC	13	72	-	-	19	2	87	-	873	-	1,066
TNC	8	10	-	-	17	18	25	750	-	-	828
WPCo	-	-	-	-	176	-	-	-	-	-	176
Total	$ 1,241	$ 584	$ 312	$ 324	$ 1,046	$ 1,601	$ 902	$ 1,020	$ 1,021	$ 485	$ 8,536

The amounts above are recorded in Property, Plant and Equipment. Sales are recorded at cost.

Global Borrowing Notes

As of December 31, 2011 and 2010, AEP has an intercompany note in place with OPCo. The debt is reflected in Long-term Debt – Affiliated on OPCo's balance sheets. OPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accrued Interest on OPCo's balance sheets.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable bases of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether they are the primary beneficiary of a VIE, management considers for each Registrant Subsidiary factors such as equity at risk, the amount of the VIE's variability the Registrant Subsidiary absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. In addition, the Registrant Subsidiaries have not provided financial or other support to any VIE that was not previously contractually required.

SWEPCo is the primary beneficiary of Sabine. I&M is the primary beneficiary of DCC Fuel. APCo, I&M, OPCo, PSO and SWEPCo each hold a significant variable interest in AEPSC. I&M and OPCo each hold a significant variable interest in AEGCo. SWEPCo holds a significant variable interest in DHLC.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2011, 2010 and 2009 were $128 million, $133 million and $99 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

The balances below represent the assets and liabilities of Sabine that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
VARIABLE INTEREST ENTITIES
December 31, 2011 and 2010
(in millions)

	Sabine	
	2011	**2010**
ASSETS		
Current Assets	$ 48	$ 50
Net Property, Plant and Equipment	154	139
Other Noncurrent Assets	42	34
Total Assets	$ 244	$ 223
LIABILITIES AND EQUITY		
Current Liabilities	$ 68	$ 33
Noncurrent Liabilities	176	190
Equity	-	-
Total Liabilities and Equity	$ 244	$ 223

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC and DCC Fuel IV LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC and DCC Fuel IV LLC are separate legal entities from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the DCC Fuel LLC and DCC Fuel II LLC leases are made semi-annually and began in April 2010 and October 2010, respectively. Payments on the DCC Fuel III LLC lease are made monthly and began in January 2011. Payments on the DCC Fuel IV LLC lease are made quarterly and began in February 2012. Payments on the leases for the years ended December 31, 2011 and 2010 were $85 million and $59 million, respectively. No payments were made to DCC Fuel in 2009. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48, 54, 54 and 54 month lease term, respectively. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the table below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

The balances below represent the assets and liabilities of DCC Fuel that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
VARIABLE INTEREST ENTITIES
December 31, 2011 and 2010
(in millions)

	DCC Fuel	
ASSETS	**2011**	**2010**
Current Assets	$ 118	$ 92
Net Property, Plant and Equipment	188	173
Other Noncurrent Assets	118	112
Total Assets	$ 424	$ 377
LIABILITIES AND EQUITY		
Current Liabilities	$ 103	$ 79
Noncurrent Liabilities	321	298
Equity	-	-
Total Liabilities and Equity	$ 424	$ 377

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2011, 2010 and 2009 were $62 million, $56 million and $43 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31, 2011		December 31, 2010	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 6	$ 6
Retained Earnings	1	1	2	2
SWEPCo's Guarantee of Debt	-	52	-	48
Total Investment in DHLC	$ 9	$ 61	$ 8	$ 56

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Years Ended December 31,		
Company	2011	2010	2009
		(in thousands)	
APCo	$ 195,787	$ 238,367	$ 200,828
I&M	126,505	139,920	128,372
OPCo	279,652	332,431	299,248
PSO	84,028	102,116	86,375
SWEPCo	130,148	147,928	129,887

The carrying amount and classification of variable interest in AEPSC's accounts payable are as follows:

	December 31,			
	2011		2010	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
		(in thousands)		
APCo	$ 20,812	$ 20,812	$ 23,230	$ 23,230
I&M	13,741	13,741	12,980	12,980
OPCo	29,823	29,823	29,603	29,603
PSO	9,280	9,280	9,384	9,384
SWEPCo	14,699	14,699	14,465	14,465

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEGCo leases the Lawrenceburg Generating Station to OPCo. AEP guarantees all the debt obligations of AEGCo. I&M and OPCo are considered to have a significant interest in AEGCo due to these transactions. I&M and OPCo are exposed to losses to the extent they cannot recover the costs of AEGCo through their normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M, OPCo and KPCo, this financing would be provided by AEP. For additional information regarding AEGCo's lease, see "Rockport Lease" section of Note 12.

Total billings from AEGCo were as follows:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
I&M	$ 228,739	$ 235,741	$ 237,372
OPCo	185,741	113,801	75,469

The carrying amount and classification of variable interest in AEGCo's accounts payable are as follows:

	December 31, 2011		2010	
Company	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
		(in thousands)		
I&M	$ 25,731	$ 25,731	$ 27,899	$ 27,899
OPCo	22,139	22,139	18,165	18,165

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

The Registrant Subsidiaries provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used by the Registrant Subsidiaries:

APCo

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 5,194,967	$ 1,783,154	2.6%	40-121	$ -	$ -	-	-
Transmission	1,943,969	457,235	1.6%	25-87	-	-	-	-
Distribution	2,845,405	595,122	3.2%	11-52	-	-	-	-
CWIP	565,841	(9,918)	NM	NM	-	-	-	-
Other	323,630	155,688	6.6%	24-55	33,696	12,735	NM	NM
Total	$ 10,873,812	$ 2,981,281			$ 33,696	$ 12,735		

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 4,736,150	$ 1,701,839	2.4%	40-121	$ -	$ -	-	-
Transmission	1,852,415	445,671	1.6%	25-87	-	-	-	-
Distribution	2,740,752	562,139	3.2%	11-52	-	-	-	-
CWIP	562,280	(18,470)	NM	NM	-	-	-	-
Other	314,301	139,167	7.8%	24-55	33,712	12,741	NM	NM
Total	$ 10,205,898	$ 2,830,346			$ 33,712	$ 12,741		

2009	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	2.3%	40-121	-	-
Transmission	1.6%	25-87	-	-
Distribution	3.2%	11-52	-	-
CWIP	NM	NM	-	-
Other	8.9%	24-55	NM	NM

NM Not Meaningful

I&M

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 3,932,472	$ 2,078,651	1.6%	59-132	$ -	$ -	-	-
Transmission	1,224,786	414,941	1.4%	46-75	-	-	-	-
Distribution	1,481,608	374,137	2.4%	14-70	-	-	-	-
CWIP	236,096	60,665	NM	NM	-	-	-	-
Other	559,698	143,312	7.4%	NM	149,860	108,214	NM	NM
Total	$ 7,434,660	$ 3,071,706			$ 149,860	$ 108,214		

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 3,774,262	$ 2,085,746	1.6%	59-132	$ -	$ -	-	-
Transmission	1,188,665	408,832	1.4%	46-75	-	-	-	-
Distribution	1,411,095	361,259	2.5%	14-70	-	-	-	-
CWIP	301,534	33,046	NM	NM	-	-	-	-
Other	572,328	129,703	11.7%	NM	147,380	106,412	NM	NM
Total	$ 7,247,884	$ 3,018,586			$ 147,380	$ 106,412		

2009	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.6%	59-132	-	-
Transmission	1.4%	46-75	-	-
Distribution	2.4%	14-70	-	-
CWIP	NM	NM	-	-
Other	12.8%	NM	NM	NM

NM Not Meaningful

OPCo

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ -	$ -	-	-	$ 9,502,614	$ 3,596,589	3.2%	35-66
Transmission	1,948,329	763,664	2.3%	27-70	-	-	-	-
Distribution	3,545,574	1,146,202	3.7%	12-56	-	-	-	-
CWIP	183,096	(3,371)	NM	NM	171,369	1,152	NM	NM
Other	407,044	222,368	8.7%	NM	139,598	15,957	NM	NM
Total	$ 6,084,043	$ 2,128,863			$ 9,813,581	$ 3,613,698		

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ -	$ -	-	-	$ 9,576,404	$ 3,494,690	3.3%	35-70
Transmission	1,896,989	733,191	2.3%	27-70	-	-	-	-
Distribution	3,422,413	1,066,797	3.7%	12-56	-	-	-	-
CWIP	193,377	(1,540)	NM	NM	132,526	9,151	NM	NM
Other	420,514	217,286	9.2%	NM	142,333	14,314	NM	NM
Total	$ 5,933,293	$ 2,015,734			$ 9,851,263	$ 3,518,155		

2009	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(In years)
Generation	-	-	3.0%	35-70
Transmission	2.3%	27-70	-	-
Distribution	3.6%	12-56	-	-
CWIP	NM	NM	NM	NM
Other	10.9%	NM	NM	NM

NM Not Meaningful

PSO

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 1,317,948	$ 652,526	1.8%	9-70	$ -	$ -	-	-
Transmission	692,644	167,827	1.9%	40-75	-	-	-	-
Distribution	1,762,110	329,041	2.4%	30-65	-	-	-	-
CWIP	70,371	(5,413)	NM	NM	-	-	-	-
Other	209,467	122,838	8.3%	5-35	5,159	(3)	NM	NM
Total	$ 4,052,540	$ 1,266,819			$ 5,159	$ (3)		

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 1,330,368	$ 648,205	1.8%	9-70	$ -	$ -	-	-
Transmission	663,994	161,835	1.9%	40-75	-	-	-	-
Distribution	1,686,470	311,005	2.4%	27-65	-	-	-	-
CWIP	59,091	(1,958)	NM	NM	-	-	-	-
Other	230,286	135,977	8.3%	5-35	5,120	-	NM	NM
Total	$ 3,970,209	$ 1,255,064			$ 5,120	$ -		

2009	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.8%	9-70	-	-
Transmission	2.0%	40-75	-	-
Distribution	2.4%	27-65	-	-
CWIP	NM	NM	-	-
Other	8.3%	5-35	NM	NM

NM Not Meaningful

SWEPCo

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 2,326,102	$ 1,060,825	2.1%	35-68	$ -	$ -	-	-
Transmission	988,534	285,785	2.3%	50-70	-	-	-	-
Distribution	1,675,764	535,565	2.6%	25-65	-	-	-	-
CWIP	1,419,216 (a)	(3,527)	NM	NM	24,353	-	NM	NM
Other	400,492	229,695	6.9%	7-47	236,527	103,569	NM	NM
Total	$ 6,810,108	$ 2,108,343			$ 260,880	$ 103,569		

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 2,297,463	$ 1,026,467	1.9%	35-68	$ -	$ -	-	-
Transmission	943,724	272,619	2.4%	50-70	-	-	-	-
Distribution	1,611,129	513,472	2.7%	25-65	-	-	-	-
CWIP	1,065,949 (a)	700	NM	NM	5,654	-	NM	NM
Other	403,881	248,544	7.7%	7-47	228,277	68,549	NM	NM
Total	$ 6,322,146	$ 2,061,802			$ 233,931	$ 68,549		

2009	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	2.7%	22-68	-	-
Transmission	2.6%	40-72	-	-
Distribution	3.6%	18-67	-	-
CWIP	NM	NM	NM	NM
Other	7.6%	7-48	NM	NM

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.
NM Not Meaningful

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

The Registrant Subsidiaries record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant and coal mining facilities as well as asbestos removal. I&M records ARO for the decommissioning of the Cook Plant. The Registrant Subsidiaries have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrant Subsidiaries plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrant Subsidiaries abandon or cease the use of specific easements, which is not expected.

As of December 31, 2011 and 2010, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $979 million and $930 million, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2011 and 2010, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $1.3 billion and $1.2 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2011 and 2010 aggregate carrying amounts of ARO by Registrant Subsidiary:

Company	ARO at December 31, 2010	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31, 2011
			(in thousands)			
APCo (a)(d)	$ 141,924	$ 9,534	$ 3	$ (3,600)	$ (35,094)	$ 112,767
I&M (a)(b)(d)	963,029	51,308	-	(1,370)	155	1,013,122
OPCo (a)(d)	189,271	13,499	165	(4,872)	43,765	241,828
PSO (a)(d)	21,557	1,708	-	(414)	(3,228)	19,623
SWEPCo (a)(c)(d)(e)	59,382	4,114	7,063	(14,947)	11,571	67,183

Company	ARO at December 31, 2009	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31, 2010
			(in thousands)			
APCo (a)(d)	$ 125,289	$ 8,541	$ 5,341	$ (4,064)	$ 6,817	$ 141,924
I&M (a)(b)(d)	894,746	47,844	7,216	(1,694)	14,917	963,029
OPCo (a)(d)	134,743	11,434	5,031	(4,208)	42,271	189,271
PSO (a)(d)	15,652	1,332	4,746	(173)	-	21,557
SWEPCo (a)(c)(d)(e)	51,684 (f)	4,290	9,056	(7,709)	2,061	59,382

(a) Includes ARO related to ash disposal facilities.
(b) Includes ARO related to nuclear decommissioning costs for the Cook Plant ($979 million and $930 million at December 31, 2011 and 2010, respectively).
(c) Includes ARO related to Sabine and DHLC.
(d) Includes ARO related to asbestos removal.
(e) The current portion of SWEPCo's ARO, totaling $1.5 million and $2.6 million, at December 31, 2011 and 2010 respectively, is included in Other Current Liabilities on SWEPCo's balance sheets.
(f) SWEPCo deconsolidated DHLC effective January 1, 2010 in accordance with the accounting guidance for "Consolidations." As a result, SWEPCo recorded only 50% ($12 million) of the final reclamation based on its share of the obligation instead of the previous 100%.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

The Registrant Subsidiaries' amounts of allowance for equity funds used during construction are summarized in the following table:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
APCo	$ 9,212	$ 2,967	$ 7,000
I&M	15,395	15,678	12,013
OPCo	5,549	5,949	6,094
PSO	1,317	804	1,787
SWEPCo	48,731	45,646	46,737

The Registrant Subsidiaries' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

Company	Years Ended December 31, 2011	2010	2009
		(in thousands)	
APCo	$ 6,257	$ 2,251	$ 6,014
I&M	7,838	8,500	8,348
OPCo	2,350	3,786	16,506
PSO	822	572	1,142
SWEPCo	40,904	33,668	29,546

Jointly-owned Electric Facilities

APCo, I&M, OPCo, PSO and SWEPCo have electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. Each Registrant Subsidiary's proportionate share of the operating costs associated with such facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

Company	Fuel Type	Percent of Ownership	Company's Share at December 31, 2011 Utility Plant in Service	Construction Work in Progress (in thousands)	Accumulated Depreciation
APCo					
John E. Amos Generating Station (Unit No. 3) (a)	Coal	33.33 %	$ 554,555	$ 16,987	$ 93,404
I&M					
Rockport Generating Plant (Unit No. 1) (e)	Coal	50.0 %	$ 759,033	$ 19,357	$ 443,857
OPCo					
John E. Amos Generating Station (Unit No. 3) (a)	Coal	66.67 %	$ 988,510	$ 15,344	$ 188,820
W.C. Beckjord Generating Station (Unit No. 6) (b)	Coal	12.5 %	19,131	108	8,476
Conesville Generating Station (Unit No. 4) (c)	Coal	43.5 %	309,771	11,633	53,980
J.M. Stuart Generating Station (d)	Coal	26.0 %	528,271	13,292	171,830
Wm. H. Zimmer Generating Station (b)	Coal	25.4 %	771,158	19,949	376,585
Transmission	NA	(f)	63,115	5,805	49,487
Total			$ 2,679,956	$ 66,131	$ 849,178
PSO					
Oklaunion Generating Station (Unit No. 1) (g)	Coal	15.6 %	$ 92,805	$ 446	$ 56,539
SWEPCo					
Dolet Hills Generating Station (Unit No. 1) (h)	Lignite	40.2 %	$ 264,487	$ 465	$ 193,565
Flint Creek Generating Station (Unit No. 1) (i)	Coal	50.0 %	118,163	6,532	62,988
Pirkey Generating Station (Unit No. 1) (i)	Lignite	85.9 %	512,557	674	361,667
Turk Generating Plant (j)	Coal	73.33 %	-	1,326,013	-
Total			$ 895,207	$ 1,333,684	$ 618,220

Company	Fuel Type	Percent of Ownership	Company's Share at December 31, 2010 Utility Plant in Service	Construction Work in Progress (in thousands)	Accumulated Depreciation
APCo					
John E. Amos Generating Station (Unit No. 3) (a)	Coal	33.33 %	$ 472,244	$ 5,638	$ 77,786
I&M					
Rockport Generating Plant (Unit No. 1) (e)	Coal	50.0 %	$ 742,538	$ 25,304	$ 437,371
OPCo					
John E. Amos Generating Station (Unit No. 3) (a)	Coal	66.67 %	$ 988,870	$ 6,354	$ 168,933
W.C. Beckjord Generating Station (Unit No. 6) (b)	Coal	12.5 %	19,079	248	8,003
Conesville Generating Station (Unit No. 4) (c)	Coal	43.5 %	300,618	8,259	49,121
J.M. Stuart Generating Station (d)	Coal	26.0 %	506,756	22,435	162,869
Wm. H. Zimmer Generating Station (b)	Coal	25.4 %	771,236	9,636	365,989
Transmission	NA	(f)	62,952	3,008	47,957
Total			$ 2,649,511	$ 49,940	$ 802,872
PSO					
Oklaunion Generating Station (Unit No. 1) (g)	Coal	15.6 %	$ 91,275	$ 1,124	$ 56,160
SWEPCo					
Dolet Hills Generating Station (Unit No. 1) (h)	Lignite	40.2 %	$ 258,261	$ 4,648	$ 191,486
Flint Creek Generating Station (Unit No. 1) (i)	Coal	50.0 %	115,742	6,725	61,750
Pirkey Generating Station (Unit No. 1) (i)	Lignite	85.9 %	502,520	10,317	358,241
Turk Generating Plant (j)	Coal	73.33 %	-	971,131	-
Total			$ 876,523	$ 992,821	$ 611,477

(a) Operated by APCo.
(b) Operated by Duke Energy Corporation, a nonaffiliated company.
(c) Operated by OPCo.
(d) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(e) Operated by I&M.
(f) Varying percentages of ownership.
(g) Operated by PSO and also jointly-owned (54.7%) by TNC.
(h) Operated by CLECO Corporation, a nonaffiliated company.
(i) Operated by SWEPCo.
(j) Turk Generating Plant is currently under construction with a projected commercial operation date in the fourth quarter of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2011, construction costs totaling $374 million have been billed to the other owners.
NA Not Applicable

16. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

The Registrant Subsidiaries recorded a charge to Other Operation expense during 2010 primarily related to severance benefits as the result of headcount reduction initiatives. The total amount incurred in 2010 by Registrant Subsidiary was as follows:

Company	Total Cost Incurred
	(in thousands)
APCo	$ 56,925
I&M	45,036
OPCo	85,400
PSO	24,005
SWEPCo	29,662

The Registrant Subsidiaries' cost reduction activity for the year ended December 31, 2011 is described in the following table:

Company	Balance at December 31, 2010	Incurred	Settled	Adjustments	Balance at December 31, 2011
			(in thousands)		
APCo	$ 3,726	$ -	$ (3,030)	$ (604)	$ 92
I&M	2,198	-	(2,006)	(192)	-
OPCo	4,373	-	(3,927)	(308)	138
PSO	1,526	-	(1,234)	(292)	-
SWEPCo	1,753	-	(1,593)	(160)	-

The remaining accruals are included primarily in Other Current Liabilities on the balance sheets.

17. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. The unaudited quarterly financial information for each Registrant Subsidiary is as follows:

Quarterly Periods Ended:	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
March 31, 2011					
Total Revenues	$ 831,820	$ 560,492	$ 1,394,190	$ 288,003	$ 362,955
Operating Income	116,061 (a)	95,994	299,396	38,881	54,528
Net Income	38,980 (a)	45,427	165,970	15,389	29,827
June 30, 2011					
Total Revenues	$ 751,445	$ 521,478	$ 1,285,558	$ 328,588	$ 399,534
Operating Income	88,567	64,351	261,534	64,185	80,054
Net Income	31,627	31,386	142,194	31,560	51,071
September 30, 2011					
Total Revenues	$ 858,336	$ 611,232	$ 1,540,231	$ 457,586	$ 534,982
Operating Income	122,716	100,352	210,453 (b)	103,006	128,406
Net Income	52,804	51,702	128,339 (b)	57,349	87,795
December 31, 2011					
Total Revenues	$ 763,624	$ 521,568	$ 1,211,132	$ 289,211	$ 356,355
Operating Income (Loss)	102,236 (c)	20,959	63,321 (d)	34,939	(12,731) (e)
Net Income (Loss)	39,347 (c)	21,159	28,490 (d)	20,330	(3,567) (e)

Quarterly Periods Ended:	APCo	I&M	OPCo (in thousands)	PSO	SWEPCo
March 31, 2010					
Total Revenues	$ 926,623	$ 553,056	$ 1,335,776	$ 237,755	$ 342,804
Operating Income	157,938	87,870	279,744	22,622	43,468
Net Income	70,282	45,058	143,553	4,139	31,083
June 30, 2010					
Total Revenues	$ 703,274	$ 509,915	$ 1,220,236	$ 327,686	$ 361,467
Operating Income (f)	9,033 (g)	42,140	186,773	39,265	43,518
Net Income (Loss) (f)	(19,619)(g)	14,602	89,664	15,489	26,705
September 30, 2010					
Total Revenues	$ 840,622	$ 608,250	$ 1,474,401	$ 426,569	$ 480,982
Operating Income	112,060	115,904	376,907	104,654	128,428
Net Income	50,071	62,300	207,922	55,432	81,685
December 31, 2010					
Total Revenues	$ 804,584	$ 524,506	$ 1,224,703	$ 281,652	$ 338,281
Operating Income	101,992	29,001 (h)	201,186 (i)	15,451	33,383
Net Income (Loss)	35,934	4,131 (h)	100,477 (i)	(2,273)	7,211

(a) Includes a $41 million increase due to the pretax write-off of a portion of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC. This increase was partially offset by the $32 million decrease due to the deferral of 2010 costs related to storms and our cost reduction initiatives as allowed by the WVPSC.

(b) Includes a $48 million pretax write-off related to Sporn Unit 5 shutdown (see Note 6), a $42 million pretax write-off related to the FGD project at Muskingum River Unit 5 (see Note 6) and a $43 million provision for refund of POLR charges (see Note 3).

(c) This increase was partially offset by a $31 million pretax write-off related to the disallowance of certain Virginia environmental costs incurred in 2009 and 2010 as a result of APCo's November 2011 Virginia SCC order. Includes a $27 million increase due to a favorable Asset Retirement Obligation adjustment related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.

(d) Includes provisions related to the FAC, the 2010 SEET and the obligation to contribute to Partnership with Ohio and Ohio Growth Fund.

(e) Includes a $49 million pretax write-off related to SWEPCo's Texas jurisdictional portion of the Turk Plant (see Note 6) as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

(f) See Note 16 for discussion of expenses related to cost reduction initiatives in 2010.

(g) Includes a $54 million pretax write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility.

(h) Includes provisions for certain regulatory and legal matters.

(i) Includes a $43 million refund provision for the 2009 SEET.

COMBINED MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain components of the Registrant Subsidiaries' management's discussion and analysis. The information in this section completes the information necessary for management's discussion and analysis of financial condition and net income and is meant to be read with (a) Management's Narrative Financial Discussion and Analysis, (b) financial statements, (c) footnotes and (d) the schedules of each individual registrant.

EXECUTIVE OVERVIEW

LITIGATION

Potential Uninsured Losses

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of a nuclear incident at the Cook Plant. Future losses or liabilities, which are not completely insured, unless recovered from customers, could have a material adverse effect on net income, cash flows and financial condition.

ENVIRONMENTAL ISSUES

The Registrant Subsidiaries are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. The Registrant Subsidiaries will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

The Registrant Subsidiaries are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of I&M's nuclear units. Management is also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. AEP, various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. The U.S. House of Representatives passed legislation called the Transparency in Regulatory Analysis of Impacts on the Nation (the TRAIN Act) that would delay implementation of certain Federal EPA rules and facilitate a comprehensive analysis of their impacts. The Senate is considering similar legislation. Management believes that further analysis and better coordination of these future environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

Management will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. The Registrant Subsidiaries should be able to recover certain of these expenditures through market prices in deregulated jurisdictions. If not, the costs of environmental compliance could adversely affect future net income, cash flows and possibly financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2011, the AEP System had a total generating capacity of nearly 36,500 MWs, of which 23,900 MWs are coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the coal-fired generating facilities. For the Registrant Subsidiaries, management's current ranges of estimates of environmental investments to comply with these proposed requirements are listed below:

	2012 to 2020 Estimated Environmental Investment	
Company	**Low**	**High**
	(in millions)	
APCo	$ 415	$ 515
I&M	1,490	1,710
OPCo	1,260	1,510
PSO	830	940
SWEPCo	1,250	1,450

For APCo, the projected environmental investments above include both the conversion of 470 MWs of coal generation to natural gas generation and the completion of 580 MWs of natural gas-fired generation in January 2012. For OPCo, the investments above include the conversion of 585 MWs of coal generation to natural gas-fired generation.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates for each Registrant Subsidiary will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose standards more stringent than the proposed rules, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

Subject to the factors listed above and based upon management's continuing evaluation, the Registrant Subsidiaries may retire the following plants or units of plants before or during 2015:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
OPCo	Conesville Plant, Unit 3	165
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528

Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. OPCo owns 12.5% (54 MWs) of one unit at that station.

Effective December 1, 2011, book depreciation rates for certain OPCo generating units were revised consistent with shortened depreciable lives for the generating units. This change in depreciable lives is expected to result in a $54 million increase in depreciation expense in 2012. However, as a result of the January and February 2012 PUCO orders and the expected corporate separation of OPCo's generation assets and the termination of the AEP Power Pool, management is reviewing the recoverability of all OPCo generation assets.

In February 2012, PSO retired Unit 3 of the 65 MW Tulsa Power Station, an older natural gas fired unit.

Plans for and the timing of conversion of some of the coal units to natural gas, installing emission control equipment on other units and closure of existing units will be impacted by changes in emission requirements and demand for power. As part of environmental compliance, management is evaluating options related to maturity of the lease for Rockport Plant Unit 2 in 2022.

To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the D.C. Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR has been challenged in the courts, and the United States Court of Appeals for the D.C. Circuit issued an order in December 2011 staying the effective date of the rule pending judicial review. CAIR remains in effect while the litigation continues. Nearly all of the states in which the Registrant Subsidiaries' power plants are located are covered by CAIR.

The Federal EPA issued final maximum achievable control technology (MACT) standards for coal and oil-fired power plants (discussed in detail below) in February 2012.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO_2 emissions from affected units in that state. PSO has challenged the FIP in the Tenth Circuit Court of Appeals. No action has been finalized in Arkansas. If the Federal EPA is upheld and similar action is taken in Arkansas, it could increase the costs of compliance, accelerate the installation of required controls and/or force the premature retirement of existing units.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units and announced a settlement agreement to issue proposed new source performance standards for utility boilers.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO_2, NO_2 and lead, and is currently reviewing the NAAQS for ozone and PM. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for facilities as a result of those evaluations. Management cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting the Registrant Subsidiaries' operations are discussed in the following sections.

Cross-State Air Pollution Rule (formerly the Clean Air Act Transport Rule)

In July 2010, the Federal EPA issued a proposed rule to replace CAIR that would impose new and more stringent requirements to control SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia.

In August 2011, the Federal EPA issued the final rule, CSAPR. The CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis beginning in 2012. Arkansas and Louisiana are subject only to the seasonal NO_x program in the final rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia have been reduced significantly in the final rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011, with an increased NO_x emission budget for the 2012 compliance year.

In October 2011, the Federal EPA released a proposed rule revising portions of the final CSAPR. The proposed rule would correct errors in unit-specific assumptions and make available additional allowances in 10 states, including Louisiana and Texas, and provide additional allowances for the new unit set aside in Arkansas. In addition, the proposed rule would make the allowance trading assurance provisions which restrict interstate trading of allowances effective January 1, 2014 instead of January 1, 2012.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the United States Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay and ordered the parties to submit schedules for expedited briefing in order to allow the case to be heard in April 2012. A final supplemental rule addressing seasonal NO_x emissions in five states was finalized in December 2011, and has been the subject of separate appeals by certain Oklahoma entities, including PSO. The Federal EPA has announced that the provisions of the supplemental rule will not be enforced while the stay of the final CSAPR remains in effect.

The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and its electric utility customers.

Mercury and Other Hazardous Air Pollutants Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule is April 16, 2012 and compliance is required within three years.

The final rule contains a slightly less stringent PM limit than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. Management is concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines.

Regional Haze – Oklahoma Affecting PSO

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA is proposing to approve all of the NO_x control measures in the SIP and disapprove the SO_2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA is proposing a FIP that would require these units to install technology capable of reducing SO_2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. PSO submitted comments on the proposed action demonstrating that the cost-effectiveness calculations performed by the Federal EPA were unsound, challenging the period for compliance with the final rule and showing that the visibility improvements secured by the proposed SIP were significant and cost-effective. The Federal EPA finalized the FIP in December 2011. PSO will appeal the FIP and pursue its claims in the Tenth Circuit Court of Appeals.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In October 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment.

Currently, approximately 40% of the coal ash and other residual products from the AEP System's generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, surface impoundments and landfills to manage these materials are currently used at the generating facilities. The Registrant Subsidiaries will incur significant costs to upgrade or close and replace their existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, management is unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. Management is evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at the AEP System's facilities. Comments on the proposal were submitted in July and August 2011.

Global Warming

National public policy makers and regulators in the 10 states the Registrant Subsidiaries serve have conflicting views on global warming. Management is focused on taking, in the short term, actions that are seen as prudent, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating assets across a range of plausible scenarios and outcomes. Management is also an active participant in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states served are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA, permitting programs for new sources and is expected to propose new source emissions standards for fossil fuel-fired plants in 2012.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where the Registrant Subsidiaries have generating facilities. Certain states, including Michigan, Ohio, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. The Registrant Subsidiaries are taking steps to comply with these requirements. In order to meet these requirements and as a key part of AEP's corporate sustainability effort, management pledged to increase wind power from 2007 levels. By the end of 2011, the AEP System secured, through power purchase agreements, 1,893 MW of wind and solar power.

The AEP System has taken measurable, voluntary actions to reduce and offset CO_2 emissions. The AEP System participates in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, but many of these programs have been discontinued due to anticipated legislative or regulatory actions. Through the end of 2010, the AEP System reduced emissions by a cumulative 96 million metric tons from adjusted baseline levels in 1998 through 2001 under Chicago Climate Exchange (CCX) rules. The AEP System's total CO_2 emissions in 2010, as reported to CCX, were 138 million metric tons. Management estimates that 2011 emissions were approximately 139 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. The Registrant Subsidiaries have been named in pending lawsuits, which management is defending. It is not possible to predict the outcome of these lawsuits or their impact on operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 5.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 would result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force the Registrant Subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on net income, cash flows and financial condition.

Global warming creates the potential for physical and financial risk. The materiality of the risks depends on whether any physical changes occur quickly or over several decades and the extent and nature of those changes. Physical risks from climate change could include changes in weather conditions. Customers' energy needs currently vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling today represent their largest energy use. To the extent weather patterns change significantly, customers' energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes could require the Registrant Subsidiaries to invest in more generating assets, transmission and other infrastructure to serve increased load, driving the cost of electricity higher. Decreased energy use due to weather changes could affect financial condition through lower sales and decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions and increased storm restoration costs. The Registrant Subsidiaries may not recover all costs related to mitigating these physical and financial risks. Weather conditions outside of the AEP System's service territory could also have an impact on revenues, either directly through changes in the patterns of off-system power purchases and sales or indirectly through demographic changes as people adapt to changing weather. The Registrant Subsidiaries buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions that create high energy demand could raise electricity prices, which would increase the cost of energy the Registrant Subsidiaries provide to customers and could provide opportunity for increased wholesale sales and higher margins.

To the extent climate change impacts a region's economic health, it could also affect revenues. The Registrant Subsidiaries' financial performance is tied to the health of the regional economies served. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of communities served. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

For additional information on climate change see Part I of the Annual Report under the headings entitled "Business – General – Environmental and Other Matters – Global Warming."

FINANCIAL CONDITION

BUDGETED CONSTRUCTION EXPENDITURES

The 2012 estimated construction expenditures by Registrant Subsidiary include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	Budgeted Construction Expenditures					
Company	Environmental	Generation	Transmission	Distribution	Other	Total
			(in millions)			
APCo	$ 78	$ 123	$ 89	$ 147	$ 12	$ 449
I&M	90	235	32	94	17	468
OPCo	123	140	82	207	17	569
PSO	43	17	35	101	8	204
SWEPCo	76	242	72	76	9	475

For 2013 and 2014, management forecasts annual construction expenditures for the AEP System to average between $3.4 billion and $3.5 billion. The projected increases are generally the result of required environmental investment to comply with Federal EPA rules and additional transmission spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. The budgeted amounts exclude equity AFUDC and capitalized interest. These construction expenditures will be funded through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. SWEPCo's budgeted construction expenditures include an amount for scheduled completion of the Turk Plant in the fourth quarter of 2012.

SIGNIFICANT TAX LEGISLATION

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs, expanded tax credits and extended the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The Small Business Jobs Act, enacted in September 2010, included a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, this act extended the time for claiming bonus depreciation and increased the deduction to 100% starting in September 2010 through 2011 and decreasing the deduction to 50% for 2012.

These enacted provisions did not have a material impact on the Registrant Subsidiaries' net income or financial condition but had a favorable impact on their cash flows in 2010 and 2011 and are expected to result in material future cash flow benefits in 2012.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosure relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about the Registrant Subsidiaries' critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

The financial statements of the Registrant Subsidiaries with cost-based rate-regulated operations (APCo, I&M, PSO, SWEPCo, and a portion of OPCo) 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.

The Registrant Subsidiaries recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the Registrant Subsidiaries match the timing of expense and income recognition with regulated revenues. Liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, the Registrant Subsidiaries record them as regulatory assets on the balance sheet. Management reviews the probability of recovery at each balance sheet date and whenever new events occur. Similarly, the Registrant Subsidiaries record regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. Refer to Note 4 for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

The Registrant Subsidiaries record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electricity utility revenues included in Revenue for the years ended December 31, 2011, 2010 and 2009 were as follows:

	Years Ended December 31,		
Company	**2011**	**2010**	**2009**
	(in thousands)		
APCo	$ (41,979)	$ 30,337	$ 25,378
I&M	(2,628)	2,194	2,695
OPCo	(20,449)	9,864	12,875
PSO	641	(4,159)	4,415
SWEPCo	643	(1,175)	(282)

Assumptions and Approach Used

For each Registrant Subsidiary, the monthly estimate for unbilled revenues is computed as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

Management considers fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

The Registrant Subsidiaries measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

The Registrant Subsidiaries reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments on risk management contracts are calculated using estimated default probabilities and recovery rates relative to the counterparties or counterparties with similar credit profiles and contractual netting agreements. With respect to hedge accounting, management assesses hedge effectiveness and evaluates a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 9 and 10. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the Registrant Subsidiaries evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. The Registrant Subsidiaries utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held-and-used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, the Registrant Subsidiary records an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of an impairment charge could be offset by the establishment of a regulatory asset, if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Management performs depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions would have been used in the applied valuation techniques. The estimate for depreciation rates takes into account the past history of interim capital replacements and the amount of salvage expected. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

AEP maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of deductible amounts as permitted under the provisions of the tax law to be paid to participants in the Qualified Plan (collectively the Pension Plans). Additionally, AEP entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. AEP also sponsors other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.

The Registrant Subsidiaries participate in the Plans. The Plans cover all employees who meet eligibility requirements.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 7 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost for the years ended December 31, 2011, 2010 and 2009 by Registrant Subsidiary for the Plans:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
Net Periodic Cost	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
	(in thousands)					
APCo	$ 15,146	$ 15,818	$ 10,459	$ 13,301	$ 19,048	$ 24,231
I&M	15,205	20,138	13,939	9,360	13,857	17,433
OPCo	19,418	19,701	11,019	16,651	24,112	31,111
PSO	7,388	5,439	3,080	3,881	7,443	9,134
SWEPCo	7,488	7,096	4,831	4,841	7,574	9,453

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2012, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 7.25%.

The expected long-term rate of return on the Plans' assets is based on AEP's targeted asset allocation and expected investment returns for each investment category. Assumptions for the Plans are summarized in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	2012 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2012 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	45 %	8.75 %	66 %	8.50 %
Fixed Income	45 %	5.25 %	33 %	5.08 %
Other Investments	10 %	8.75 %	-%	- %
Cash and Cash Equivalents	-%	-%	1 %	1.55 %
Total	100 %		100 %	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 7.25% is a reasonable estimate of the long-term rate of return on the Plans' assets despite the recent market volatility. The Pension Plans' assets had an actual gain of 8.1% and 13.4% for the years ended December 31, 2011 and 2010, respectively. The Postretirement Plans' assets had an actual gain of 0.4% and 11.3% for the years ended December 31, 2011 and 2010, respectively. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the 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, 2011, AEP had cumulative losses of approximately $104 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses may result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance. See the table below for the amount of cumulative losses by Registrant Subsidiary.

Cumulative Losses – Deferred Asset Loss	December 31, 2011	
	(in thousands)	
APCo	$	13,764
I&M		12,152
OPCo		22,330
PSO		5,927
SWEPCo		6,170

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate at December 31, 2011 under this method was 4.55% for the Qualified Plan, 4.4% for the Nonqualified Plans and 4.75% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 7.25%, a discount rate of 4.55% and 4.4% and various other assumptions, management estimates that the pension costs by Registrant Subsidiary for all pension plans will approximate the amounts in the following table. Based on an expected rate of return on the OPEB plans' assets of 7.25%, a discount rate of 4.75% and various other assumptions, management estimates Postretirement Plan costs by Registrant Subsidiary will approximate the amounts in the following table.

	Pension Plans			Other Postretirement Benefit Plans		
Estimated Postretirement Plan Costs	Years Ended December 31,					
	2012	**2013**	**2014**	**2012**	**2013**	**2014**
	(in thousands)					
APCo	$ 16,131	$ 17,965	$ 14,072	$ 16,414	$ 14,253	$ 12,876
I&M	16,221	18,288	15,221	12,348	11,480	10,712
OPCo	18,335	22,007	16,468	21,298	19,675	18,165
PSO	7,598	10,293	9,221	5,248	4,907	4,551
SWEPCo	7,924	10,744	9,799	6,405	6,023	5,614

Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to each Registrant Subsidiary's populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets increased to $4.3 billion at December 31, 2011 from $3.9 billion at December 31, 2010 primarily due to a $450 million contribution. During 2011, the Qualified Plan paid $287 million and the nonqualified plans paid $7 million in benefits to plan participants. The value of AEP's Postretirement Plans' assets decreased to $1.4 billion at December 31, 2011 from $1.5 billion at December 31, 2010 primarily due to benefits paid exceeding contributions. The Postretirement Plans paid $150 million in benefits to plan participants during 2011. See Note 7 for complete details by Registrant Subsidiary.

Nature of Estimates Required

The Registrant Subsidiaries participate in AEP sponsored pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under "Compensation" and "Plan Accounting" accounting guidance. The measurement of pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

APCo

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in thousands)			
Effect on December 31, 2011 Benefit Obligations				
Discount Rate	$ (35,309)	$ 38,790	$ (23,643)	$ 26,307
Compensation Increase Rate	929	(835)	-	-
Cash Balance Crediting Rate	4,700	(3,927)	NA	NA
Health Care Cost Trend Rate	NA	NA	19,970	(18,143)
Effect on 2011 Periodic Cost				
Discount Rate	(2,458)	2,662	(1,918)	2,132
Compensation Increase Rate	534	(484)	-	-
Cash Balance Crediting Rate	1,748	(1,596)	NA	NA
Health Care Cost Trend Rate	NA	NA	3,185	(2,849)
Expected Return on Plan Assets	(2,824)	2,824	(1,130)	1,136

I&M

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in thousands)			
Effect on December 31, 2011 Benefit Obligations				
Discount Rate	$ (31,941)	$ 35,245	$ (17,539)	$ 19,622
Compensation Increase Rate	1,393	(1,266)	-	-
Cash Balance Crediting Rate	5,338	(4,600)	NA	NA
Health Care Cost Trend Rate	NA	NA	15,032	(13,586)
Effect on 2011 Periodic Cost				
Discount Rate	(2,098)	2,273	(1,329)	1,473
Compensation Increase Rate	456	(414)	-	-
Cash Balance Crediting Rate	1,492	(1,363)	NA	NA
Health Care Cost Trend Rate	NA	NA	2,185	(1,960)
Expected Return on Plan Assets	(2,411)	2,411	(892)	896

OPCo

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in thousands)			
Effect on December 31, 2011 Benefit Obligations				
Discount Rate	$ (50,279)	$ 55,100	$ (32,553)	$ 36,449
Compensation Increase Rate	1,559	(1,417)	-	-
Cash Balance Crediting Rate	6,277	(5,291)	NA	NA
Health Care Cost Trend Rate	NA	NA	27,815	(25,084)
Effect on 2011 Periodic Cost				
Discount Rate	(3,682)	3,988	(2,513)	2,793
Compensation Increase Rate	800	(726)	-	-
Cash Balance Crediting Rate	2,618	(2,391)	NA	NA
Health Care Cost Trend Rate	NA	NA	4,165	(3,727)
Expected Return on Plan Assets	(4,229)	4,229	(1,534)	1,541

PSO

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in thousands)			
Effect on December 31, 2011 Benefit Obligations				
Discount Rate	$ (12,844)	$ 14,008	$ (8,050)	$ 9,016
Compensation Increase Rate	837	(767)	-	-
Cash Balance Crediting Rate	3,926	(3,709)	NA	NA
Health Care Cost Trend Rate	NA	NA	6,798	(6,133)
Effect on 2011 Periodic Cost				
Discount Rate	(998)	1,081	(599)	664
Compensation Increase Rate	218	(197)	-	-
Cash Balance Crediting Rate	709	(648)	NA	NA
Health Care Cost Trend Rate	NA	NA	983	(882)
Expected Return on Plan Assets	(1,445)	1,445	(409)	411

SWEPCo

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in thousands)			
Effect on December 31, 2011 Benefit Obligations				
Discount Rate	$ (12,940)	$ 14,115	$ (9,712)	$ 10,897
Compensation Increase Rate	829	(750)	-	-
Cash Balance Crediting Rate	4,671	(4,407)	NA	NA
Health Care Cost Trend Rate	NA	NA	8,339	(7,516)
Effect on 2011 Periodic Cost				
Discount Rate	(999)	1,082	(694)	770
Compensation Increase Rate	218	(197)	-	-
Cash Balance Crediting Rate	710	(648)	NA	NA
Health Care Cost Trend Rate	NA	NA	1,140	(1,023)
Expected Return on Plan Assets	(1,146)	1,146	(474)	476

NA Not Applicable

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncement Adopted During 2011

The Registrant Subsidiaries adopted ASU 2011-5 "Presentation of Comprehensive Income" effective for the 2011 Annual Report including the deferral of the reclassification adjustment presentation provisions of ASU 2011-05 under the terms in ASU 2011-12, "Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income." The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income. This standard changed the presentation of the financial statements but did not affect the calculation of net income or comprehensive income.

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of the Registrant Subsidiaries' operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, leases, insurance, hedge accounting and consolidation policy. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.