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DESCRIPTION OF DOCUMENT
DIRECT TESTIMONY of KEVIN. M. MURRAY

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF RESULTS OF OPERATIONS

$ in millions		2010		2009		2008
	For the years ended December 31,					
Revenues	$	**1,790.5**	$	1,550.4	$	1,572.9
Cost of revenues:						
Fuel		**371.9**		323.6		231.4
Purchased power		**383.5**		259.2		379.9
Total cost of revenues		755.4		582.8		611.3
Gross margin		**1,035.1**		967.6		961.6
Operating expenses:						
Operation and maintenance		**330.1**		293.4		273.0
Depreciation and amortization		**130.7**		135.5		127.8
General taxes		**124.1**		116.8		124.2
Total operating expenses		**584.9**		545.7		525.0
Operating income		**450.2**		421.9		436.6
Other income / (expense), net:						
Investment income		**1.7**		2.8		7.0
Interest expense		**(37.1)**		(38.5)		(36.5)
Other income (deductions)		**(1.9)**		(2.8)		(1.1)
Total other income / (expense), net		**(37.3)**		(38.5)		(30.6)
Earnings before income tax		**412.9**		383.4		406.0
Income tax expense		**135.2**		124.5		120.2
Net income		**277.7**		258.9		285.8
Dividends on preferred stock		**0.9**		0.9		0.9
Earnings on common stock	**$**	**276.8**	$	258.0	$	284.9

See Notes to Consolidated Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF CASH FLOWS

$ in millions		For the years ended December 31, 2010		2009		2008
Cash flows from operating activities:						
Net income	$	**277.7**	$	258.9	$	285.8
Adjustments to reconcile Net income to Net cash provided by operating activities:						
Depreciation and amortization		**130.7**		135.5		127.8
Deferred income taxes		**54.3**		200.1		40.9
Changes in certain assets and liabilities:						
Accounts receivable		**15.2**		25.7		(3.5)
Inventories		**10.1**		(20.5)		(0.2)
Prepaid taxes		**(8.9)**		—		—
Taxes applicable to subsequent years		**(3.6)**		(1.3)		(9.9)
Deferred regulatory costs, net		**16.0**		(24.6)		(12.9)
Accounts payable		**16.9**		(65.9)		26.9
Accrued taxes payable		**1.7**		(0.9)		(50.0)
Accrued interest payable		**(5.4)**		0.2		—
Pension, retiree and other benefits		**(58.2)**		15.2		31.3
Unamortized investment tax credit		**(2.8)**		(2.8)		(2.8)
Other		**2.7**		(5.9)		(40.7)
Net cash provided by operating activities		**446.4**		513.7		392.7
Cash flows from investing activities:						
Capital expenditures		**(150.0)**		(167.4)		(242.0)
Purchases of short-term investments and securities		**1.4**		1.4		1.9
Net cash used for investing activities		**(148.6)**		(166.0)		(240.1)
Cash flows from financing activities:						
Dividends paid on common stock to parent		**(300.0)**		(325.0)		(155.0)
Dividends paid on preferred stock		**(0.9)**		(0.9)		(0.9)
Issuance of pollution control bonds, net		—		—		98.4
Retirement of pollution control bonds		—		—		(90.0)
Pollution control bond proceeds held in trust		—		—		(10.0)
Withdrawal of restricted funds held in trust, net		—		14.5		32.5
Withdrawals from revolving credit facilities		—		260.0		115.0
Repayment of borrowings from revolving credit facilities		—		(260.0)		(115.0)
Payment of short-term debt held by parent		—		—		(20.0)
Net cash used for financing activities		**(300.9)**		(311.4)		(145.0)
Cash and cash equivalents:						
Net change		**(3.1)**		36.3		7.6
Balance at beginning of period		**57.1**		20.8		13.2
Cash and cash equivalents at end of period	$	**54.0**	$	57.1	$	20.8
Supplemental cash flow information:						
Interest paid, net of amounts capitalized	$	**45.1**	$	39.5	$	33.4
Income taxes (refunded) / paid, net	$	**87.0**	$	(94.7)	$	127.0
Non-cash financing and investing activities:						
Accruals for capital expenditures	$	**23.2**	$	20.8	$	34.1

See Notes to Consolidated Financial Statements.

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THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions		At December 31, 2010		2009
ASSETS				
Current assets:				
Cash and cash equivalents	$	**54.0**	$	57.1
Accounts receivable, net (Note 2)		**178.0**		192.0
Inventories (Note 2)		**114.2**		124.3
Taxes applicable to subsequent years		**62.8**		59.2
Other prepayments and current assets		**42.7**		26.0
Total current assets		**451.7**		458.6
Property, plant and equipment:				
Property, plant and equipment		**5,093.7**		5,011.0
Less: Accumulated depreciation and amortization		**(2,453.1)**		(2,370.7)
		2,640.6		2,640.3
Construction work in process		**119.6**		87.9
Total net property, plant and equipment		**2,760.2**		2,728.2
Other noncurrent assets:				
Regulatory assets (Note 3)		**189.0**		214.2
Other assets		**74.5**		56.4
Total other noncurrent assets		**263.5**		270.6
Total Assets	**$**	**3,475.4**	$	3,457.4

See Notes to Consolidated Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions		At December 31, 2010		2009
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities:				
Current portion - long-term debt (Note 5)	$	**0.1**	$	100.6
Accounts payable		**95.7**		75.1
Accrued taxes		**66.6**		68.6
Accrued interest		**7.7**		13.1
Customers security deposits		**18.7**		19.4
Other current liabilities		**33.6**		23.2
Total current liabilities		**222.4**		300.0
Noncurrent liabilities:				
Long-term debt (Note 5)		**884.0**		783.7
Deferred taxes (Note 6)		**598.0**		553.0
Regulatory liabilities (Note 3)		**139.4**		125.4
Pension, retiree and other benefits		**64.9**		111.7
Unamortized investment tax credit		**32.4**		35.2
Other deferred credits		**131.9**		122.9
Total noncurrent liabilities		**1,850.6**		1,731.9
Redeemable preferred stock		**22.9**		22.9
Commitments and contingencies (Note 16)				
Common shareholder's equity:				
Common stock, at par value of $0.01 per share		**0.4**		0.4
Other paid-in capital		**782.4**		781.6
Accumulated other comprehensive loss		**(20.2)**		(19.7)
Retained earnings		**616.9**		640.3
Total common shareholder's equity		**1,379.5**		1,402.6
Total Liabilities and Shareholder's Equity	$	**3,475.4**	$	3,457.4

See Notes to Consolidated Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF SHAREHOLDER'S EQUITY

in millions (except Outstanding Shares)	Common Stock (a) Outstanding Shares	Common Stock (a) Amount	Other Paid-in Capital	Accumulated Other Comprehensive Income / (Loss)	Retained Earnings	Total
Beginning balance	41,172,173	$ 0.4	$ 784.8	$ 17.1	$ 577.6	$ 1,379.9
2008:						
Net income					285.8	
Change in unrealized gains (losses) on financial instruments, net of tax				(9.8)		
Change in deferred gains (losses) on cash flow hedges, net of tax				(1.7)		
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax				(21.7)		
Total comprehensive income						252.6
Common stock dividends					(155.0)	(155.0)
Preferred stock dividends					(0.9)	(0.9)
Tax effects to equity			0.3			0.3
Employee / Director stock plans			(2.0)			(2.0)
Ending balance	41,172,173	$ 0.4	$ 783.1	$ (16.1)	$ 707.5	$ 1,474.9
2009:						
Net income					258.9	
Change in unrealized gains (losses) on financial instruments, net of tax				2.7		
Change in deferred gains (losses) on cash flow hedges, net of tax				(3.7)		
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax				(2.7)		
Total comprehensive income						255.2
Common stock dividends					(325.0)	(325.0)
Preferred stock dividends					(0.9)	(0.9)
Tax effects to equity			0.8			0.8
Employee / Director stock plans			(2.5)			(2.5)
Other			0.2	0.1	(0.2)	0.1
Ending balance	41,172,173	$ 0.4	$ 781.6	$ (19.7)	$ 640.3	$ 1,402.6
2010:						
Net income					277.7	
Change in unrealized gains (losses) on financial instruments, net of tax				(1.0)		
Change in deferred gains (losses) on cash flow hedges, net of tax				(2.8)		

Change in unrealized gains (losses) on pension and postretirement benefits, net of tax				3.3		
Total comprehensive income						277.2
Common stock dividends					(300.0)	(300.0)
Preferred stock dividends					(0.9)	(0.9)
Tax effects to equity			0.2			0.2
Employee / Director stock plans			0.4			0.4
Other			0.2		(0.2)	—
Ending balance	41,172,173	$ 0.4	$ 782.4	$ (20.2)	$ 616.9	$ 1,379.5

(a) $0.01 par value, 50,000,000 shares authorized.

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

This report includes the combined filing of **DPL** and **DP&L**. **DP&L** is the principal subsidiary of **DPL** providing approximately 93% of **DPL's** total consolidated gross margin and approximately 91% of **DPL's** total consolidated asset base. Throughout this report, the terms "we," "us," "our" and "ours" are used to refer to both **DPL** and **DP&L**, respectively and altogether, unless the context indicates otherwise. Discussions or areas of this report that apply only to **DPL** or **DP&L** will clearly be noted in the section.

Some of the Notes presented in this report are only applicable to **DPL** or **DP&L** as indicated. The other Notes apply to both registrants and the financial information presented is segregated by registrant.

1. Overview and Summary of Significant Accounting Policies

Description of Business

DPL is a diversified regional energy company organized in 1985 under the laws of Ohio. During 2010, **DPL**, for the first time, met the GAAP requirements for separate segment reporting. **DPL's** two segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary. Refer to Note 17 of Notes to Consolidated Financial Statements for more information relating to these reportable segments.

DP&L is a public utility incorporated in 1911 under the laws of Ohio. **DP&L** is engaged in generation, transmission, distribution and the sale of electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. Electricity for **DP&L's** 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense. **DP&L's** sales reflect the general economic conditions and seasonal weather patterns of the area. **DP&L** sells any excess energy and capacity into the wholesale market.

DPLER sells competitive retail electric service, under contract, primarily to commercial and industrial customers. DPLER has approximately 9,000 customers currently located throughout Ohio. All of DPLER's electric energy was purchased from **DP&L** to meet these sales obligations.

DPL's other significant subsidiaries include DPLE, which owns and operates peaking generating facilities from which it makes wholesale sales of electricity and MVIC, our captive insurance company that provides insurance services to us and our subsidiaries. All of **DPL's** subsidiaries are wholly-owned.

DPL also has a wholly-owned business trust, DPL Capital Trust II, formed for the purpose of issuing trust capital securities to investors.

DP&L's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law. Accordingly, **DP&L** applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates, and regulatory liabilities when current cost recoveries in customer rates relate to expected future costs.

Financial Statement Presentation

We prepare Consolidated Financial Statements for **DPL**. **DPL's** Consolidated Financial Statements include the accounts of **DPL** and its wholly-owned subsidiaries except for DPL Capital Trust II which is not consolidated, consistent with the provisions of GAAP.

DP&L has undivided ownership interests in seven electric generating facilities and numerous transmission facilities. These undivided interests in jointly-owned facilities are accounted for on a pro rata basis in **DP&L's** Financial Statements.

Certain immaterial amounts from prior periods have been reclassified to conform to the current reporting presentation.

All material intercompany accounts and transactions are eliminated in consolidation.

The preparation of financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the revenues and expenses of the periods reported. Actual results could differ from these estimates. Significant items subject to such estimates and judgments include: the carrying value of Property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits.

Revenue Recognition

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We consider revenue realized, or realizable, and earned when persuasive evidence of an arrangement exists, the products or services have been provided to the customer, the sales price is fixed or determinable, and collection is reasonably assured. Energy sales to customers are based on the reading of their meters that occurs on a systematic basis throughout the month. We recognize the revenues on our statements of results of operations using an accrual method for retail and other energy sales that have not yet been billed, but where electricity has been consumed. This is termed "unbilled revenues" and is a widely recognized and accepted practice for utilities. At the end of each month, unbilled revenues are determined by the estimation of unbilled energy provided to customers since the date of the last meter reading, estimated line losses, the assignment of unbilled energy provided to customer classes and the average rate per customer class.

All of the power produced at the generation plants is sold to an RTO and we in turn purchase it back from the RTO to supply our customers. These power sales and purchases are reported on a net hourly basis as revenues or purchased power on our statements of results of operations. We record expenses when purchased electricity is received and when expenses are incurred, with the exception of the ineffective portion of certain power purchase contracts that are derivatives and qualify for hedge accounting. We also have certain derivative contracts that do not qualify for hedge accounting, and their unrealized gains or losses are recorded prior to the receipt of electricity.

Allowance for Uncollectible Accounts

We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues.

Property, Plant and Equipment

We record our ownership share of our undivided interest in jointly-held plants as an asset in property, plant and equipment. Property, plant and equipment are stated at cost. For regulated transmission and distribution property, cost includes direct labor and material, allocable overhead expenses and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of borrowed funds and equity used to finance regulated construction projects. Capitalization of AFUDC ceases at either project completion or at the date specified by regulators. AFUDC capitalized in 2010, 2009 and 2008 was not material.

For unregulated generation property, cost includes direct labor and material, allocable overhead expenses and interest capitalized during construction using the provisions of GAAP relating to the accounting for capitalized interest. Capitalized interest was $1.5 million, $2.4 million and $8.9 million in 2010, 2009 and 2008, respectively.

For substantially all depreciable property, when a unit of property is retired, the original cost of that property less any salvage value is charged to Accumulated depreciation and amortization consistent with the composite method of depreciation.
Property is evaluated for impairment when events or changes in circumstances indicate that its carrying amount may not be recoverable.
At December 31, 2010, neither **DPL** nor **DP&L** had any material plant acquisition adjustments or other plant-related adjustments.

Repairs and Maintenance

Costs associated with maintenance activities, primarily power plant outages, are recognized at the time the work is performed. These costs, which include labor, materials and supplies, and outside services required to maintain equipment and facilities, are capitalized or expensed based on defined units of property.

Depreciation Study — Change in Estimate

Depreciation expense is calculated using the straight-line method, which allocates the cost of property over its estimated useful life. For **DPL's** generation, transmission and distribution assets, straight-line depreciation is applied monthly on an average composite basis using group rates. In July 2010, **DPL** completed a depreciation rate study for non-regulated generation property based on its property, plant and equipment balances at December 31, 2009, with certain adjustments for subsequent property additions. The results of the depreciation study concluded that many of **DPL's** composite depreciation rates should be reduced due to projected useful asset lives which are longer than those previously estimated. **DPL** adjusted the depreciation rates for its non-regulated generation property effective July 1, 2010, resulting in a net reduction of depreciation expense. For the year ended December 31, 2010, the net reduction in depreciation expense amounted to $4.8 million ($3.2 million net of tax) and increased diluted EPS by approximately $0.03 per share. On an annualized basis, the net reduction in depreciation expense is projected to be approximately $9.6 million ($6.4 million net of tax) or approximately $0.06 per diluted share.
For **DPL's** generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 2.6% in 2010, 2.7% in 2009 and 2.7% in 2008.
The following is a summary of **DPL's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2010 and 2009:

DPL

$ in millions	2010	Composite Rate	2009	Composite Rate
Regulated:				
Transmission	$ 360.6	2.5%	$ 355.3	2.4%
Distribution	1,256.5	3.4%	1,206.7	3.7%
General	79.6	3.7%	76.8	3.1%
Non-depreciable	58.6	N/A	57.8	N/A
Total regulated	$ 1,755.3		$ 1,696.6	
Unregulated:				
Production / Generation	$ 3,543.6	2.3%	$ 3,519.2	2.5%
Other	36.1	3.6%	35.0	3.7%
Non-depreciable	18.6	N/A	18.4	N/A
Total unregulated	$ 3,598.3		$ 3,572.6	
Total property, plant and equipment in service	$ 5,353.6	2.6%	$ 5,269.2	2.7%

For **DP&L's** generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 2.6% in 2010, 2.7% in 2009 and 2.6% in 2008.

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The following is a summary of **DP&L's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2010 and 2009:

DP&L

$ in millions	2010	Composite Rate	2009	Composite Rate
Regulated:				
Transmission	$ 360.6	2.5%	$ 355.3	2.4%
Distribution	1,256.5	3.4%	1,206.7	3.7%
General	79.5	3.7%	76.8	3.1%
Non-depreciable	58.7	N/A	57.8	N/A
Total regulated	$ 1,755.3		$ 1,696.6	
Unregulated:				
Production / Generation	$ 3,323.0	2.3%	$ 3,299.1	2.4%
Non-depreciable	15.4	N/A	15.3	N/A
Total unregulated	$ 3,338.4		$ 3,314.4	
Total property, plant and equipment in service	$ 5,093.7	2.6%	$ 5,011.0	2.7%

AROs

We recognize AROs in accordance with GAAP which requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time those obligations are incurred. Upon initial recognition of a legal liability, costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the related asset. Our legal obligations associated with the retirement of our long-lived assets consisted primarily of river intake and discharge structures, coal unloading facilities, loading docks, ice breakers and ash disposal facilities. Our generation AROs are recorded within other deferred credits on the balance sheets. Estimating the amount and timing of future expenditures of this type requires significant judgment. Management routinely updates these estimates as additional information becomes available.

Changes in the Liability for Generation AROs

$ in millions	2010	2009
Balance at January 1	$ 16.2	$ 13.2
Accretion expense	0.2	0.8
Additions	0.8	2.1
Settlements	(0.3)	(0.5)
Estimated cash flow revisions	0.6	0.6
Balance at December 31	$ 17.5	$ 16.2

Asset Removal Costs

We continue to record cost of removal for our regulated transmission and distribution assets through our depreciation rates and recover those amounts in rates charged to our customers. There are no known legal AROs associated with these assets. We have recorded $107.9 million and $99.1 million in estimated costs of removal at December 31, 2010 and 2009, respectively, as regulatory liabilities for our transmission and distribution property. These amounts represent the excess of the cumulative removal costs recorded through depreciation rates versus the cumulative removal costs actually incurred. See Note 3 of Notes to Consolidated Financial Statements.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		2010		2009
Balance at January 1	$	99.1	$	96.0
Additions		11.2		6.5
Settlements		(2.4)		(3.4)
Balance at December 31	$	107.9	$	99.1

Regulatory Accounting

In accordance with GAAP, regulatory assets and liabilities are recorded in the balance sheets for our regulated transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and Regulatory liabilities represent current recovery of expected future costs.

We evaluate our Regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator. If we were required to terminate application of these GAAP provisions for all of our regulated operations, we would have to write off the amounts of all regulatory assets and liabilities to the statements of results of operations at that time. See Note 3 of Notes to Consolidated Financial Statements.

Inventories

Inventories are carried at average cost and include coal, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations.

We account for our emission allowances as inventory and record emission allowance inventory at weighted average cost. We calculate the weighted average cost by each vintage (year) for which emission allowances can be used and charge to fuel costs the weighted average cost of emission allowances used each month. Net gains or losses on the sale of excess emission allowances, representing the difference between the sales proceeds and the weighted average cost of emission allowances, are recorded as a component of our fuel costs and are reflected in Operating income when realized. During the periods ended December 31, 2010, 2009 and 2008, we recognized gains from the sale of emission allowances in the amounts of $0.8 million, $5.0 million and $34.8 million, respectively. Beginning in January 2010, a portion of the gains on emission allowances was used to reduce the overall fuel rider charged to our SSO retail customers.

Income Taxes

GAAP requires an asset and liability approach for financial accounting and reporting of income taxes with tax effects of differences, based on currently enacted income tax rates, between the financial reporting and tax basis of accounting reported as deferred tax assets or liabilities in the balance sheets. Deferred tax assets are recognized for deductible temporary differences. Valuation allowances are provided against deferred tax assets unless it is more likely than not that the asset will be realized.

Investment tax credits, which have been used to reduce federal income taxes payable, are deferred for financial reporting purposes and are amortized over the useful lives of the property to which they relate. For rate-regulated operations, additional deferred income taxes and offsetting regulatory assets or liabilities are recorded to recognize that income taxes will be recoverable or refundable through future revenues.

DPL files a consolidated U.S. federal income tax return in conjunction with its subsidiaries. The consolidated tax liability is allocated to each subsidiary based on the separate return method which is specified in our tax allocation agreement and which provides a consistent, systematic and rational approach. See Note 6 of Notes to Consolidated Financial Statements.

Financial Instruments

We classify our investments in debt and equity financial instruments of publicly traded entities into different categories: held-to-maturity and available-for-sale. Available-for-sale securities are carried at fair value and unrealized gains and losses on those securities, net of deferred income taxes, are presented as a separate component of shareholders' equity. Other-than-temporary declines in value are recognized currently in earnings. Financial instruments classified as held-to-maturity are carried at amortized cost. The cost basis for public equity security and fixed maturity investments is average cost and amortized cost, respectively.

Short-Term Investments

DPL utilizes VRDNs as part of its short-term investment strategy. The VRDNs are of high credit quality and are secured by irrevocable letters of credit from major financial institutions. VRDN investments have variable rates tied to short-term interest rates. Interest rates are reset every seven days and these VRDNs can be tendered for sale back to the financial institution upon notice. Although **DPL's** VRDN investments have original maturities over one year, they are frequently re-priced and trade at par. We account for these VRDNs as available-for-sale securities and record them as short-term investments at fair value, which approximates cost, since they are highly liquid and are readily available to support **DPL's** current operating needs.

DPL also holds investment-grade fixed income corporate securities in its short-term investment portfolio. These securities are accounted for as held-to-maturity investments.

Accounting for Taxes Collected from Customers and Remitted to Governmental Authorities

DP&L collects certain excise taxes levied by state or local governments from its customers. **DP&L's** excise taxes are accounted for on a gross basis and recorded as revenues and general taxes in the accompanying Statements of Results of Operations as follows:

	For the years ended December 31,		
$ in millions	2010	2009	2008
State/Local excise taxes	$ 51.7	$ 49.5	$ 52.3

Share-Based Compensation

We measure the cost of employee services received and paid with equity instruments based on the fair-value of such equity instrument on the grant date. This cost is recognized in results of operations over the period that employees are required to provide service. Liability awards are initially recorded based on the fair-value of equity instruments and are to be re-measured for the change in stock price at each subsequent reporting date until the liability is ultimately settled. The fair-value for employee share options and other similar instruments at the grant date are estimated using option-pricing models and any excess tax benefits are recognized as an addition to paid-in capital. The reduction in income taxes payable from the excess tax benefits is presented in the statements of cash flows within Cash flows from financing activities. See Note 10 of Notes to Consolidated Financial Statements.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. All highly liquid short-term investments with original maturities of three months or less are considered cash equivalents.

Financial Derivatives

All derivatives are recognized as either assets or liabilities in the balance sheets and are measured at fair value. Changes in the fair value are recorded in earnings unless they are designated as a cash flow hedge of a forecasted transaction or qualify for the normal purchases and sales exception.

We use forward contracts to reduce our exposure to changes in energy and commodity prices and as a hedge against the risk of changes in cash flows associated with expected electricity purchases. These purchases are used to hedge our full load requirements. We also hold forward sales contracts that hedge against the risk of changes in cash flows associated with power sales during periods of projected generation facility availability. We use cash flow hedge accounting when the hedge or a portion of the hedge is deemed to be highly effective and MTM accounting when the hedge or a portion of the hedge is not effective. See Note 9 of Notes to Consolidated Financial Statements.

Insurance and Claims Costs

In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of **DPL**, provides insurance coverage to us, our subsidiaries and, in some cases, our partners in commonly owned facilities we operate, for workers' compensation, general liability, property damage, and directors' and officers' liability. Insurance and claims costs on the Consolidated Balance Sheets of **DPL** include insurance reserves of approximately $10.1 million and $16.2 million for 2010 and 2009, respectively. Furthermore, **DP&L** is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. In addition, **DP&L** has medical, life, and disability reserves for claims costs below certain coverage thresholds of third-party providers. We record these additional insurance and claims costs of approximately $19.0 million and $11.3 million for 2010 and 2009, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The MVIC reserves at **DPL** and the workers' compensation, medical, life and disability reserves at **DP&L** are actuarially determined based on a reasonable estimation of insured events occurring. There is uncertainty associated with these loss estimates and actual results may differ from the estimates. Modification of these loss estimates based on experience and changed circumstances is reflected in the period in which the estimate is re-evaluated.

DPL Capital Trust II

DPL has a wholly-owned business trust, DPL Capital Trust II (the Trust), formed for the purpose of issuing trust capital securities to third-party investors. Effective 2003, **DPL** deconsolidated the Trust upon adoption of the accounting standards related to variable interest entities and currently treats the Trust as a nonconsolidated subsidiary. The Trust holds mandatorily redeemable trust capital securities. The investment in the Trust, which amounts to $3.6 million and $3.8 million at December 31, 2010 and 2009, respectively, is included in Other deferred assets within Other noncurrent assets. **DPL** also has a note payable to the Trust amounting to $142.6 million at December 31, 2010 and 2009 that was established upon the Trust's deconsolidation in 2003. See Note 5 of Notes to Consolidated Financial Statements.

In addition to the obligations under the note payable mentioned above, **DPL** also agreed to a security obligation which represents a full and unconditional guarantee of payments to the capital security holders of the Trust.

Related Party Transactions

In the normal course of business, **DP&L** enters into transactions with other subsidiaries of **DPL**. All material intercompany accounts and transactions are eliminated in **DPL's** Consolidated Financial Statements. The following table provides a summary of amounts transacted by **DP&L** with its related parties:

	For the years ended December 31,		
$ in millions	**2010**	**2009**	**2008**
DP&L Revenues:			
Sales to DPLER (a)	$ **238.5**	$ 64.8	$ 150.6
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC (b)	$ **(3.3)**	$ (3.4)	$ (3.5)
Expense recoveries for services provided to DPLER (c)	$ **5.8**	$ 1.5	$ 0.9

*(a) **DP&L** sells power to DPLER to satisfy the electric requirements of DPLER's retail customers. The revenue dollars associated with sales to DPLER are recorded as wholesale revenues by **DP&L**. The increase in **DP&L's** sales to DPLER during the year ended December 31, 2010 compared to the same period in 2009 is primarily due to customers electing to switch their generation service from **DP&L** to DPLER.*

*(b) MVIC, a wholly-owned captive insurance subsidiary of **DPL**, provides insurance coverage to **DP&L** and other **DPL** subsidiaries for workers' compensation, general liability, property damages and directors' and officers' liability. These amounts represent insurance premiums paid by **DP&L** to MVIC.*

*(c) In the normal course of business **DP&L** incurs and records expenses on behalf of DPLER. Such expenses include but are not limited to employee-related expenses, accounting, information technology, payroll, legal and other administration expenses. **DP&L** subsequently charges these expenses to DPLER at **DP&L's** cost and credits the expense in which they were initially recorded.*

Recently Adopted Accounting Standards

Variable Interest Entities

We adopted ASU 2009-02 "Omnibus Update" (formerly SFAS No. 167, a revision to FASB Interpretation No. 46(R), "*Consolidation of Variable Interest Entities") (ASU 2009-02),* on January 1, 2010. This standard updates FASC Topic 810 "Consolidation." ASU 2009-02 changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar) rights should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance. ASU 2009-02 did not have a material impact on our overall results of operations, financial condition or cash flows.

Fair Value Disclosures

We adopted ASU 2010-06 "Fair Value Measurements and Disclosures" (ASU 2010-06) on January 1, 2010. This standard updates FASC Topic 820 "*Fair Value Measurements and Disclosures.*" ASU 2010-06 requires additional disclosures about fair value measurements including transfers in and out of Levels 1 and 2 and a higher level of disaggregation for the different types of financial instruments. For the reconciliation of Level 3 fair value measurements, information about purchases, sales, issuances and settlements are presented separately. ASU 2010-06 did not have a material impact on our overall results of operations, financial condition or cash flows. See Note 8 of Notes to Consolidated Financial Statements.

Recently Issued Accounting Standards

There were no recently issued accounting standards that could potentially have a significant impact on our financial statements.

2. Supplemental Financial Information

DPL Inc.

$ in millions	At December 31, 2010	At December 31, 2009
Accounts receivable, net:		
Unbilled revenue	$ 84.5	$ 74.9
Customer receivables	113.9	99.4
Amounts due from partners in jointly-owned plants	7.0	12.6
Coal sales	4.0	10.6
Other	7.0	16.4
Provision for uncollectible accounts	(0.9)	(1.1)
Total accounts receivable, net	$ 215.5	$ 212.8
Inventories, at average cost:		
Fuel, limestone and emission allowances	$ 73.2	$ 85.8
Plant materials and supplies	38.8	38.5
Other	3.3	1.4
Total inventories, at average cost	$ 115.3	$ 125.7

DP&L

$ in millions	At December 31, 2010	At December 31, 2009
Accounts receivable, net:		
Unbilled revenue	$ 64.3	$ 71.0
Customer receivables	95.6	94.4
Amounts due from partners in jointly-owned plants	7.0	12.6
Coal sales	4.0	10.6
Other	7.9	4.5
Provision for uncollectible accounts	(0.8)	(1.1)
Total accounts receivable, net	$ 178.0	$ 192.0
Inventories, at average cost:		
Fuel, limestone and emission allowances	$ 73.2	$ 85.8
Plant materials and supplies	37.7	37.1
Other	3.3	1.4
Total inventories, at average cost	$ 114.2	$ 124.3

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3. Regulatory Matters

In accordance with GAAP, regulatory assets and liabilities are recorded in the consolidated balance sheets for our regulated electric transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and regulatory liabilities represent current recovery of expected future costs or gains probable of recovery being reflected in future rates.

We evaluate our regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator.

Regulatory assets and liabilities on the consolidated balance sheets of **DPL** and **DP&L** include:

$ in millions	Type of Recovery (a)	Amortization Through		At December 31, 2010		At December 31, 2009
Regulatory Assets:						
Deferred recoverable income taxes	B/C	Ongoing	$	**29.9**	$	36.8
Pension benefits	C	Ongoing		**81.1**		85.2
Unamortized loss on reacquired debt	C	Ongoing		**14.3**		15.6
Electric Choice systems costs	F	2011		**0.9**		4.0
Regional transmission organization costs	D	2014		**5.5**		7.0
TCRR, transmission, ancillary and other PJM-related costs	F	2011		**11.8**		5.5
RPM capacity costs	F	2011		**2.7**		20.0
Deferred storm costs - 2008	D			**16.9**		16.0
Power plant emission fees	C	Ongoing		**6.6**		6.3
CCEM smart grid and advanced metering infrastructure costs	D			**6.6**		6.5
CCEM energy efficiency program costs	F	Ongoing		**4.8**		3.6
Other costs				**7.9**		7.7
Total regulatory assets			$	**189.0**	$	214.2
Regulatory Liabilities:						
Estimated costs of removal - regulated property			$	**107.9**	$	99.1
SECA net revenue subject to refund				**15.4**		20.1
Postretirement benefits				**6.1**		5.1
Fuel and purchased power recovery costs	C	Ongoing		**10.0**		—
Other costs				**—**		1.1
Total regulatory liabilities			$	**139.4**	$	125.4

(a) B — Balance has an offsetting liability resulting in no impact on rate base.

C — Recovery of incurred costs without a rate of return.

D — Recovery not yet determined, but is probable of occurring in future rate proceedings.

F — Recovery of incurred costs plus rate of return.

Regulatory Assets

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow through items as the result of amounts previously provided to customers. This is the cumulative flow through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes will decrease over time.

Pension benefits represent the qualifying FASC Topic 715 "Compensation — Retirement Benefits" costs of our regulated operations that for ratemaking purposes are deferred for future recovery. We 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 (OCI), 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. This regulatory asset represents the regulated portion that would otherwise be charged as a loss to OCI.

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed in prior periods. These costs are being amortized over the lives of the original issues in accordance with FERC and PUCO rules.

Electric Choice systems costs represent costs incurred to modify the customer billing system for unbundled customer rates and electric choice utility bills relative to other generation suppliers and information reports provided to the state administrator of the low-income payment program. In March 2006, the PUCO issued an order that approved our tariff as filed. We began collecting this rider immediately and expect to recover all costs over five years.
Regional transmission organization costs represent costs incurred to join an RTO. The recovery of these costs will be requested in a future FERC rate case. In accordance with FERC precedence, we are amortizing these costs over a 10-year period that began in 2004 when we joined the PJM RTO.
TCRR, transmission, ancillary and other PJM-related costs represent the costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. We review retail rates and are required to make true-up adjustments on an annual basis.
RPM capacity costs represent the costs related to PJM RPM assigned to **DP&L** that have not yet been recovered through the RPM rider. We review this rate and make true-up adjustments on an annual basis.
Deferred storm costs — 2008 relate to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other major 2008 storms. On January 14, 2009, the PUCO granted **DP&L** the authority to defer these costs with a return until such time that **DP&L** seeks recovery in a future rate proceeding.
Power plant emission fees represent costs paid to the State of Ohio since 2002. An application is pending before the PUCO to amend an approved rate rider that had been in effect to collect fees that were paid and deferred in years prior to 2002. The deferred costs incurred prior to 2002 have been fully recovered. As the previously approved rate rider continues to be in effect, we believe these costs are probable of future rate recovery.
CCEM smart grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and implementation of AMI. Consistent with the ESP Stipulation, **DP&L** re-filed its smart grid and AMI business cases with the PUCO on August 4, 2009 seeking recovery of costs associated with a 10-year plan to deploy smart meters, distribution and substation automation, core telecommunications, supporting software and in-home technologies. On October 19, 2010, **DP&L** elected to withdraw the re-filed case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects **DP&L** to continue to monitor other utilities' Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that **DP&L** will, when appropriate, file new Smart Grid and/or AMI business cases in the future. We plan to file to recover these deferred costs in a future regulatory rate proceeding. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.
CCEM energy efficiency program costs represent costs incurred to develop and implement various new customer programs addressing energy efficiency. These costs are being recovered through an energy efficiency rider that began July 1, 2009 and is subject to a two-year true-up for any over/under recovery of costs.
Other costs primarily include consumer education advertising costs regarding electric deregulation, settlement system costs, other PJM and rate case costs and alternative energy costs that are or will be recovered over various periods.

Regulatory Liabilities

Estimated costs of removal — regulated property reflect an estimate of amounts collected in customer rates for costs that are expected to be incurred in the future to remove existing transmission and distribution property from service when the property is retired.

SECA net revenue subject to refund represents our deferral of revenues and costs that were billed to PJM transmission customers and paid to transmission owners during 2005 and 2006, but which remain subject to litigation before the FERC and potential reversal. **DP&L** is both a transmission customer and a transmission owner. SECA revenue and expenses represent FERC-ordered transitional payments for the use of transmission lines within PJM. We began receiving and paying these transitional payments in May 2005, subject to refund. Since 2005, a large number of settlements have been entered into among various market participants including **DP&L**. A final FERC order on this issue was issued on May 21, 2010 that substantially supports **DP&L's** and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. **DP&L**, along with other transmission owners in PJM and the Midwest Independent System Operator (MISO) made a compliance filing at FERC on August 19, 2010 that fully demonstrated all payment obligations to and from all parties within PJM and the MISO. The FERC has made no ruling regarding the compliance filing and some parties have requested rehearing by FERC of its May 21, 2010 order. It is expected that any order on the compliance filing and any order regarding the rehearing request will be appealed for Court review. In October 2010, **DP&L** entered into another settlement agreement to settle a portion of SECA amounts still owed to **DP&L**. With respect to unsettled claims, **DP&L** management believes it has deferred as a regulatory liability the appropriate amounts that are subject to refund. The eventual outcome of this litigation is uncertain.

Postretirement benefits represent the qualifying FASC Topic 715 "Compensation — Retirement Benefits" gains related to our regulated operations that, for ratemaking purposes, are probable of being reflected in future rates. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, 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. This regulatory liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

Fuel and purchased power recovery costs represent prudently incurred fuel, purchased power, derivative, emission and other related costs which will be recovered from or returned to customers in the future through the operation of the fuel and purchased power recovery rider. The fuel and purchased power recovery rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter. **DP&L** implemented the fuel and purchased power recovery rider on January 1, 2010. **DP&L** is currently undergoing an audit of its fuel and purchased power recovery rider and, as a result, there is some uncertainty as to the costs that will be approved for recovery. Independent third parties conduct the fuel audit in accordance with the PUCO standards. **DP&L** anticipates that some of this uncertainty will be resolved during the summer of 2011 after completion of the fuel audit. As a result of the fuel audit, **DP&L** may record a favorable or unfavorable adjustment to earnings. Based on past PUCO precedent, we believe these deferred costs are probable of future recovery or repayment in the case of over recovery.

4. Ownership of Coal-fired Facilities

DP&L and other Ohio utilities have undivided ownership interests in seven coal-fired electric generating facilities and numerous transmission facilities. Certain expenses, primarily fuel costs for the generating units, are allocated to the owners based on their energy usage. The remaining expenses, investments in fuel inventory, plant materials and operating supplies, and capital additions are allocated to the owners in accordance with their respective ownership interests. As of December 31, 2010, we had $56 million of construction work in process at such facilities. **DP&L's** share of the operating cost of such facilities is included within the corresponding line in the Statements of Results of Operations and **DP&L's** share of the investment in the facilities is included in the Balance Sheets.

DP&L's undivided ownership interest in such facilities as well as our wholly-owned coal fired Hutchings plant at December 31, 2010, is as follows:

	DP&L Share		DP&L Investment			
	Ownership (%)	Production Capacity (MW)	Gross Plant In Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)	SCR and FGD Equipment Installed and In Service (Yes/No)
Production Units:						
Beckjord Unit 6	50.0	210	$ 75	$ 52	$ 2	No
Conesville Unit 4	16.5	129	118	27	5	Yes
East Bend Station	31.0	186	200	131	1	Yes
Killen Station	67.0	402	611	288	3	Yes
Miami Fort Units 7 and 8	36.0	368	347	130	7	Yes
Stuart Station	35.0	820	697	266	25	Yes
Zimmer Station	28.1	365	1,059	612	12	Yes
Transmission (at varying percentages)			91	56	—	
Total		2,480	$ 3,198	$ 1,562	$ 55	
Wholly-owned production unit:						
Hutchings Station	100.0	388	$ 123	$ 111	$ 1	No

DP&L's share of operating costs associated with the jointly-owned generating facilities is included within the corresponding line in the Statements of Results of Operations.

5. Debt Obligations

Long-term Debt

$ in millions	At December 31, 2010	At December 31, 2009
DP&L		
First mortgage bonds maturing in October 2013 - 5.125%	$ **470.0**	$ 470.0
Pollution control series maturing in January 2028 - 4.70%	**35.3**	35.3
Pollution control series maturing in January 2034 - 4.80%	**179.1**	179.1
Pollution control series maturing in September 2036 - 4.80%	**100.0**	100.0
Pollution control series maturing in November 2040 - variable rates: 0.16% - 0.35% and 0.24% - 0.85% (a)	**100.0**	—
	884.4	784.4
Obligation for capital lease	**0.1**	—
Unamortized debt discount	**(0.5)**	(0.7)
Total long-term debt - **DP&L**	$ **884.0**	$ 783.7
DPL		
Senior notes maturing in September 2011 - 6.875%	**—**	297.4
Note to DPL Capital Trust II maturing in September 2031 - 8.125%	**142.6**	142.6
Unamortized debt discount	**—**	(0.2)
Total long-term debt - **DPL**	$ **1,026.6**	$ 1,223.5

Current portion - Long-term Debt

$ in millions	At December 31, 2010	At December 31, 2009
DP&L		
Pollution control series maturing in November 2040 - variable rates: 0.16% - 0.35% and 0.24% - 0.85% (a)	$ **—**	$ 100.0
Obligation for capital lease	**0.1**	0.6
Total current portion - long-term debt - **DP&L**	$ **0.1**	$ 100.6
DPL		
Senior notes maturing in September 2011 - 6.875%	**297.4**	—
Total current portion - long-term debt - **DPL**	$ **297.5**	$ 100.6

(a) Range of interest rates for the twelve months ended December 31, 2010 and December 31, 2009, respectively.

At December 31, 2010, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions	DPL	DP&L
Due within one year	$ 297.5	$ 0.1
Due within two years	0.1	0.1
Due within three years	470.0	470.0
Due within four years	—	—
Due within five years	—	—
Thereafter	557.0	414.4
	$ 1,324.6	$ 884.6

Debt

On November 21, 2006, **DP&L** entered into a $220 million unsecured revolving credit agreement. This agreement has a five-year term that expires on November 21, 2011 and provides **DP&L** with the ability to increase the size of the facility by an additional $50 million at any time. **DP&L** had no outstanding borrowings under this credit facility at December 31, 2010. Fees associated with this credit facility were approximately $1.2 million and $0.9 million during the years ended December 31, 2010 and 2009, respectively. Changes in **DP&L's** credit ratings may affect fees and the applicable interest rate. This revolving credit agreement contains a $50 million letter of credit sublimit. As of December 31, 2010, **DP&L** had no outstanding letters of credit against the facility.

On December 4, 2008, the OAQDA issued $100 million of collateralized, variable rate Revenue Refunding Bonds Series A and B due November 1, 2040. In turn, **DP&L** borrowed these funds from the OAQDA and issued corresponding First Mortgage Bonds to support repayment of the funds. The payment of principal and interest on each series of the bonds when due is backed by a standby LOC issued by JPMorgan Chase Bank, N.A. This LOC facility, which expires in December 2013, is irrevocable and has no subjective acceleration clauses. The bonds were classified within the current portion of long term debt at December 31, 2009 as the standby LOC backing the bonds was set to expire during the fourth quarter of 2010. During the fourth quarter of 2010, **DP&L** renewed the standby LOC to back the payment of principal and interest on each series of the bonds when due. The new LOC facility expires in December 2013 therefore the bonds have been reclassified to Long-term debt on the balance sheets of **DPL** and **DP&L**.

On March 31, 2009, **DPL** paid its $175 million 8.00% Senior notes when the notes became due.

On April 21, 2009, **DP&L** entered into a $100 million unsecured revolving credit agreement with a syndicated bank group. The agreement was for a 364-day term and expired on April 20, 2010.

On December 21, 2009, **DPL** purchased $52.4 million principal amount of DPL Capital Trust II 8.125% capital securities in a privately negotiated transaction. As part of this transaction, **DPL** paid a $3.7 million, or 7%, premium which was recorded within Interest expense on the Consolidated Statements of Results of Operations.

On April 20, 2010, **DP&L** entered into a $200 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on April 20, 2013 and provides **DP&L** with the ability to increase the size of the facility by an additional $50 million. **DP&L** had no outstanding borrowings under this credit facility at December 31, 2010. Fees associated with this credit facility were approximately $0.5 million during the period between April 20, 2010 and December 31, 2010. This facility also contains a $50 million letter of credit sublimit. As of December 31, 2010, **DP&L** had no outstanding letters of credit against the facility.

Substantially all property, plant and equipment of **DP&L** is subject to the lien of the mortgage securing **DP&L's** First and Refunding Mortgage, dated October 1, 1935, with the Bank of New York Mellon as Trustee.

See Note 18 of Notes to Consolidated Financial Statements for additional discussion relating to **DPL's** 8.125% Note to DPL — Capital Trust II.

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6. Income Taxes

For the years ended December 31, 2010, 2009 and 2008, **DPL's** components of income tax expense were as follows:

DPL

$ in millions	For the years ended December 31, 2010	2009	2008
Computation of Tax Expense			
Federal income tax (a)	$ **151.7**	$ 119.9	$ 121.9
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**2.4**	0.9	4.1
Depreciation of AFUDC - Equity	**(2.2)**	(2.0)	(4.3)
Investment tax credit amortized	**(2.8)**	(2.8)	(2.8)
Section 199 - domestic production deduction	**(9.1)**	(4.6)	(4.2)
Accrual (settlement) for open tax years (b)	**0.2**	(1.4)	(7.2)
Other, net (c)	**2.8**	2.5	(4.6)
Total tax expense	$ **143.0**	$ 112.5	$ 102.9
Components of Tax Expense			
Federal - Current	$ **84.8**	$ (84.4)	$ 60.9
State and Local - Current	**1.1**	(1.8)	1.8
Total Current	$ **85.9**	$ (86.2)	$ 62.7
Federal - Deferred	$ **55.9**	$ 196.0	$ 37.9
State and Local - Deferred	**1.2**	2.7	2.3
Total Deferred	$ **57.1**	$ 198.7	$ 40.2
Total tax expense	$ **143.0**	$ 112.5	$ 102.9

Components of Deferred Tax Assets and Liabilities

$ in millions	At December 31, 2010	2009
Net Noncurrent Assets / (Liabilities)		
Depreciation / property basis	$ **(618.6)**	$ (583.5)
Income taxes recoverable	**(10.3)**	(12.9)
Regulatory assets	**(12.4)**	(16.5)
Investment tax credit	**11.3**	12.3
Investment loss	**(0.5)**	0.1
Compensation and employee benefits	**21.0**	35.8
Insurance	**(1.5)**	0.8
Other (d)	**(14.4)**	(5.2)
Net noncurrent (liabilities)	$ **(625.4)**	$ (569.1)
Net Current Assets (e)		
Other	$ **1.1**	$ 3.7
Net current assets	$ **1.1**	$ 3.7

(a) The statutory tax rate of 35% was applied to pre-tax earnings from continuing operations.

(b) DPL has recorded an expense of $0.2 million, benefits of $2.9 million and $40.7 million in 2010, 2009 and 2008, respectively, for tax deduction or income positions taken in prior tax returns that we believe were properly treated on such tax returns but for which it is possible that these positions may be contested. The 2008 amount relates to the ODT settlement discussed further below in Note 6 of Notes to Consolidated Financial Statements.

(c) Includes a benefit of $0.3 million, an expense of $2.0 million, a benefit of $3.8 million in 2010, 2009 and 2008, respectively, of income tax related to adjustments from prior years.

(d) *The Other noncurrent liabilities caption includes deferred tax assets of $13.1 million in 2010 and $12.0 million in 2009 related to state and local tax net operating loss carryforwards, net of related valuation allowances of $13.1 million in 2010 and $12.0 million in 2009. As of December 31, 2010 and 2009, all deferred tax assets related to net operating losses were valued at zero. These net operating loss carryforwards expire from 2017 to 2025.*

(e) *Amounts are included within Other prepayments and current assets on the Consolidated Balance Sheets of* ***DPL****.*

DPL has recorded $0.2 million, $0.7 million and $0.3 million in 2010, 2009 and 2008, respectively, for tax benefits related to stock-based compensation that were credited to Retained earnings. **DPL** has recorded $5.8 million of tax expense in 2010 and $1.7 million and $11.5 million of tax benefits in 2009 and 2008, respectively, for tax benefits related to pensions, postretirement benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

For the years ended December 31, 2010, 2009 and 2008, **DP&L's** components of income tax were as follows:

DP&L

	For the years ended December 31,		
$ in millions	2010	2009	2008
Computation of Tax Expense			
Federal income tax (a)	$ **144.2**	$ 134.2	$ 142.1
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**1.9**	0.4	2.6
Depreciation of AFUDC - Equity	**(2.2)**	(2.0)	(4.3)
Investment tax credit amortized	**(2.8)**	(2.8)	(2.8)
Section 199 - domestic production deduction	**(9.1)**	(4.6)	(4.2)
Accrual (settlement) for open tax years (b)	**0.2**	(1.4)	(7.2)
Other, net (c)	**3.0**	0.7	(6.0)
Total tax expense	$ **135.2**	$ 124.5	$ 120.2
Components of Tax Expense			
Federal - Current	$ **83.1**	$ (70.3)	$ 81.2
State and Local - Current	**0.8**	(2.5)	0.9
Total Current	$ **83.9**	$ (72.8)	$ 82.1
Federal - Deferred	$ **50.1**	$ 194.4	$ 36.4
State and Local - Deferred	**1.2**	2.9	1.7
Total Deferred	$ **51.3**	$ 197.3	$ 38.1
Total tax expense	$ **135.2**	$ 124.5	$ 120.2

Components of Deferred Tax Assets and Liabilities

	At December 31,	
$ in millions	2010	2009
Net Noncurrent Assets / (Liabilities)		
Depreciation / property basis	$ **(595.6)**	$ (563.7)
Income taxes recoverable	**(10.3)**	(12.9)
Regulatory assets	**(12.4)**	(16.5)
Investment tax credit	**11.3**	12.3
Compensation and employee benefits	**21.0**	35.8
Other	**(12.0)**	(8.0)
Net noncurrent (liabilities)	$ **(598.0)**	$ (553.0)
Net Current Assets (d)		
Other	$ **1.2**	$ 3.7
Net current assets	$ **1.2**	$ 3.7

(a) *The statutory tax rate of 35% was applied to pre-tax earnings.*

(b) ***DP&L** has recorded an expense of $0.2 million and benefits of $2.9 million and $40.7 million in 2010, 2009 and 2008, respectively, of tax provisions for tax deduction or income positions taken in prior tax returns that we believe were properly treated on such tax returns but for which it is possible that these positions may be contested. The 2008 amount relates to the ODT settlement discussed further below in Note 6 of Notes to Consolidated Financial Statements.*

(c) *Includes a benefit of $0.3 million, an expense of $0.8 million, and a benefit of $3.5 million in 2010, 2009 and 2008, respectively, of income tax related to adjustments from prior years.*

(d) *Amounts are included within Other prepayments and current assets on the Balance Sheets of* ***DP&L****.*

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DP&L has recorded $0.2 million, $0.7 million and $0.3 million in 2010, 2009 and 2008, respectively, for tax benefits related to stock-based compensation that were credited to Other paid-in capital. **DP&L** has recorded $0.1 million of tax expense in 2010 and $0.5 million and $16.5 million of tax benefits in 2009 and 2008, respectively, for tax benefits related to pensions, postretirement benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

Accounting for Uncertainty in Income Taxes

We apply the provisions of GAAP relating to the accounting for uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits for **DPL** and **DP&L** is as follows:

$ in millions	2010	2009
Balance at beginning of year	$ 19.3	$ 1.9
Tax positions taken during prior periods	(0.4)	—
Tax positions taken during current period	—	20.6
Settlement with taxing authorities	0.3	(3.2)
Lapse of applicable statute of limitations	0.2	—
Balance at end of year	$ 19.4	$ 19.3

Of the December 31, 2010 balance of unrecognized tax benefits, $20.6 million is due to uncertainty in the timing of deductibility offset by $1.1 million of unrecognized tax liabilities that would affect the effective tax rate.

We recognize interest and penalties related to unrecognized tax benefits in Income tax expense. The amount of interest and penalties accrued was an expense of $0.3 million as of December 31, 2010, a benefit of $0.1 million as of December 31, 2009 and an expense of less than $0.1 million as of December 31, 2008. The amount of interest and penalties recorded in the statements of results of operations for 2010, 2009 and 2008 was an expense of $0.2 million, and benefits of $0.1 million and $9.0 million, respectively.

Following is a summary of the tax years open to examination by major tax jurisdiction:

U.S. Federal — 2007 and forward

State and Local — 2005 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The examination is still ongoing and we do not expect the results of this examination to have a material impact on our financial condition, results of operations and cash flows.

On December 17, 2010, the Federal Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 was enacted. This legislation amends, creates and extends various Federal tax statutes. Among the various statutes is the extension and expansion of capital expensing provisions, commonly referred to as bonus depreciation, for 2010, 2011 and 2012. While these provisions are not expected to have a material impact on our results of operations, we anticipate they will result in positive cash flow contributions over the next few years.

On June 21, 2010, Ohio Senate Bill 232 was enacted. This legislation eliminates Ohio's tangible personal property tax and real property taxes on generation for renewable and advanced energy project facilities that begin construction before January 1, 2012, produce energy by 2013 (or 2017 for nuclear, clean coal and cogeneration projects) and create Ohio jobs. Rules containing implementation provisions were proposed on September 29, 2010. We do not anticipate this law and the related rules will have a material impact on either **DPL's** or **DP&L's** financial condition, results of operations and cash flows.

On February 13, 2006, we received correspondence from the ODT notifying us that the ODT had completed their examination and review of our Ohio Corporation Franchise Tax Returns for tax years 2002 through 2004 and that the final proposed audit adjustments resulted in a balance due of $90.8 million before interest and penalties. On June 27, 2008, we entered into a $42.0 million settlement agreement with the ODT resolving all outstanding audit issues and appeals, including uncertain tax positions for tax years 1998 through 2006. The $42 million payment was made to the ODT in July 2008. Due to this settlement agreement, the balance of our unrecognized state tax liabilities recorded at December 31, 2007, in the amount of $56.3 million, was reversed resulting in a recorded income tax benefit of $8.5 million, net of federal tax impact, in 2008.

7. Pension and Postretirement Benefits

DP&L sponsors a defined benefit pension plan for substantially all employees. For collective bargaining employees, the defined benefits are based on a specific dollar amount per year of service. For all other employees (management employees), the defined benefit pension plan is based primarily on compensation and years of service. As of December 31, 2010, this pension plan was closed to new management employees. A participant is 100% vested in all amounts credited to his or her account upon the completion of five vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan, or upon a change of control or the participant's death or disability. If a participant's employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination.

Management employees beginning employment on or after January 1, 2011 will be enrolled in a cash balance plan. Similar to the defined benefit pension plan for management employees, the cash balance benefits are based on compensation and years of service. A participant shall become 100% vested in all amounts credited to his or her account upon the completion of three vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan or upon a change of control or the participant's death or disability. If a participant's employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination. Vested benefits in the cash balance plan are fully portable upon termination of employment.

In addition, we have a Supplemental Executive Retirement Plan (SERP) for certain active and retired key executives. Benefits under this SERP have been frozen and no additional benefits can be earned. The SERP was replaced by the DPL Inc. Supplemental Executive Defined Contribution Retirement Plan (SEDCRP). The Compensation Committee of the Board of Directors designates the eligible employees. Pursuant to the SEDCRP, we provide a supplemental retirement benefit to participants by crediting an account established for each participant in accordance with the Plan requirements. We designate as hypothetical investment funds under the SEDCRP one or more of the investment funds provided under The Dayton Power and Light Company Employee Savings Plan. Each participant may change his or her hypothetical investment fund selection at specified times. If a participant does not elect a hypothetical investment fund(s), then we select the hypothetical investment fund(s) for such participant. We also have an unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. The unfunded liabilities for these agreements and the SEDCRP were $1.8 million and $1.4 million at December 31, 2010 and 2009, respectively.

We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. In February 2010, **DP&L** contributed $20.0 million to the defined benefit plan. In September 2010, **DP&L** contributed an additional $20.0 million to the defined benefit plan for a total contribution of $40.0 million in 2010.

Qualified employees who retired prior to 1987 and their dependents are eligible for health care and life insurance benefits until their death, while qualified employees who retired after 1987 are eligible for life insurance benefits and partially subsidized health care. The partially subsidized health care is at the election of the employee, who pays the majority of the cost, and is available only from their retirement until they are covered by Medicare at age 65. We have funded a portion of the union-eligible benefits using a Voluntary Employee Beneficiary Association Trust.

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Regulatory assets and liabilities are recorded for the portion of the under- or over-funded obligations related to the transmission and distribution areas of our electric business and for 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. These regulatory assets and liabilities represent the regulated portion that would otherwise be charged or credited to AOCI. We have historically recorded these costs on the accrual basis and this is how these costs have been historically recovered. This factor, combined with the historical precedents from the PUCO and FERC, make these costs probable of future rate recovery.

The following tables set forth our pension and postretirement benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2010 and 2009. The amounts presented in the following tables for pension include both the defined benefit pension plan and the SERP in the aggregate, and use a measurement date of December 31, 2010 and 2009. The amounts presented for postretirement include both health and life insurance benefits and use a measurement date of December 31, 2010 and 2009.

$ in millions	Pension 2010	Pension 2009	Postretirement 2010	Postretirement 2009
Change in Benefit Obligation During Year				
Benefit obligation at January 1	$ **323.9**	$ 294.6	$ **26.2**	$ 25.2
Service cost	**4.8**	3.6	**0.1**	—
Interest cost	**17.7**	18.1	**1.2**	1.5
Plan amendments	**—**	7.2	**—**	1.1
Actuarial (gain) / loss	**8.0**	20.3	**(2.0)**	0.3
Benefits paid	**(20.6)**	(19.9)	**(2.0)**	(1.9)
Medicare Part D Reimbursement	**—**	—	**0.2**	—
Benefit obligation at December 31	$ **333.8**	$ 323.9	$ **23.7**	$ 26.2
Change in Plan Assets During Year				
Fair value of plan assets at January 1	$ **243.4**	$ 225.4	$ **5.0**	$ 6.2
Actual return / (loss) on plan assets	**28.6**	37.5	**0.3**	0.4
Contributions to plan assets	**40.4**	0.4	**1.5**	0.3
Benefits paid	**(20.6)**	(19.9)	**(2.0)**	(2.3)
Medicare reimbursements	**—**	—	**—**	0.4
Fair value of plan assets at December 31	$ **291.8**	$ 243.4	$ **4.8**	$ 5.0
Funded Status of Plan	$ **(42.0)**	$ (80.5)	$ **(18.9)**	$ (21.2)
Amounts Recognized in the Balance Sheets at December 31				
Current liabilities	$ **(0.4)**	$ (0.4)	$ **(0.6)**	$ (0.4)
Noncurrent liabilities	**(41.6)**	(80.1)	**(18.3)**	(20.8)
Net asset / (liability) at December 31	$ **(42.0)**	$ (80.5)	$ **(18.9)**	$ (21.2)
Amounts Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost / (credit)	$ **16.8**	$ 20.4	$ **0.9**	$ 1.1
Net actuarial loss / (gain)	**125.4**	130.9	**(7.6)**	(6.9)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	$ **142.2**	$ 151.3	$ **(6.7)**	$ (5.8)
Recorded as:				
Regulatory asset	$ **80.0**	$ 84.6	$ **0.5**	$ 0.6
Regulatory liability	**—**	—	**(6.1)**	(5.1)
Accumulated other comprehensive income	**62.2**	66.7	**(1.1)**	(1.3)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	$ **142.2**	$ 151.3	$ **(6.7)**	$ (5.8)

The accumulated benefit obligation for our defined benefit pension plans was $320.9 million and $314.0 million at December 31, 2010 and 2009, respectively.

The net periodic benefit cost (income) of the pension and postretirement benefit plans at December 31 were:

Net Periodic Benefit Cost / (Income)	Pension			Postretirement		
$ in millions	2010	2009	2008	2010	2009	2008
Service cost	$ 4.8	$ 3.6	$ 3.2	$ 0.1	$ —	$ —
Interest cost	17.7	18.1	16.7	1.2	1.5	1.4
Expected return on assets (a)	(22.4)	(22.5)	(24.1)	(0.3)	(0.4)	(0.4)
Amortization of unrecognized:						
Actuarial (gain) / loss	7.2	4.4	2.6	(1.1)	(0.7)	(0.9)
Prior service cost	3.7	3.4	2.4	0.1	0.1	—
Net periodic benefit cost / (income) before adjustments	$ 11.0	$ 7.0	$ 0.8	$ —	$ 0.5	$ 0.1

(a)For purposes of calculating the expected return on pension plan assets, under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be amortized into the MRVA equally over a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets was approximately $274 million in 2010, $275 million in 2009 and $293 million in 2008.

Other Changes in Plan Assets and Benefit Obligation Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities

	Pension		Postretirement	
$ in millions	2010	2009	2010	2009
Net actuarial (gain) / loss	$ 1.9	$ 5.3	$ (1.9)	$ 0.3
Prior service cost / (credit)	—	7.2	—	1.1
Reversal of amortization item:				
Net actuarial (gain) / loss	(7.2)	(4.4)	1.1	0.7
Prior service cost / (credit)	(3.7)	(3.4)	(0.1)	(0.1)
Transition (asset) / obligation	—	—	—	—
Total recognized in Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	$ (9.0)	$ 4.7	$ (0.9)	$ 2.0
Total recognized in net periodic benefit cost and Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	$ 2.0	$ 11.7	$ (0.9)	$ 2.5

Estimated amounts that will be amortized from Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2011 are:

$ in millions	Pension	Postretirement
Net actuarial (gain) / loss	$ 9.1	$ 0.1
Prior service cost / (credit)	2.2	(0.9)

Our expected return on plan asset assumptions, used to determine benefit obligations, are based on historical long-term rates of return on investments, which use the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors, such as inflation and interest rates, as well as asset diversification and portfolio rebalancing, are evaluated when long-term capital market assumptions are determined. Peer data and historical returns are reviewed to verify reasonableness and appropriateness.

For 2011, we have decreased our expected long-term rate of return on assets assumption from 8.50% to 8.00% for pension plan assets. We are maintaining our expected long-term rate of return on assets assumption at approximately 6.00% for postretirement benefit plan assets. These expected returns are based primarily on portfolio investment allocation. There can be no assurance of our ability to generate these rates of return in the future.

Our overall discount rate was evaluated in relation to the December 31, 2010 Hewitt Top Quartile Yield Curve which represents a portfolio of top-quartile AA-rated bonds used to settle pension obligations. Peer data and historical returns were also reviewed to verify the reasonableness and appropriateness of our discount rate used in the calculation of benefit obligations and expense.

The weighted average assumptions used to determine benefit obligations for the years ended December 31, 2010 and 2009 were:

	Pension		Postretirement	
Benefit Obligation Assumptions	**2010**	**2009**	**2010**	**2009**
Discount rate for obligations	**5.31%**	5.75%	**4.96%**	5.35%
Rate of compensation increases	**3.94%**	4.44%	**N/A**	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2010, 2009 and 2008 were:

Net Periodic Benefit	Pension			Postretirement		
Cost / (Income) Assumptions	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Discount rate	**5.75%**	6.25%	6.00%	**5.35%**	6.25%	6.00%
Expected rate of return on plan assets	**8.50%**	8.50%	8.50%	**6.00%**	6.00%	6.00%
Rate of compensation increases	**4.44%**	5.44%	5.44%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2010 and 2009 are as follows:

	Expense		Benefit Obligations	
Health Care Cost Assumptions	**2010**	**2009**	**2010**	**2009**
Pre - age 65				
Current health care cost trend rate	**9.50%**	9.50%	**8.50%**	9.50%
Year trend reaches ultimate	**2015**	2014	**2018**	2015
Post - age 65				
Current health care cost trend rate	**9.00%**	9.00%	**8.00%**	9.00%
Year trend reaches ultimate	**2014**	2013	**2017**	2014
Ultimate health care cost trend rate	**5.00%**	5.00%	**5.00%**	5.00%

The assumed health care cost trend rates have an effect on the amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects on the net periodic postretirement benefit cost and the accumulated postretirement benefit obligation:

Effect of Change in Health Care Cost Trend Rate

$ in millions	One-percent increase	One-percent decrease
Service cost plus interest cost	$ —	$ —
Benefit obligation	$ 0.9	$ (0.8)

The following benefit payments, which reflect future service, are expected to be paid as follows:

Estimated Future Benefit Payments and Medicare Part D Reimbursements

$ in millions	Pension	Postretirement
2011	$ 21.3	$ 2.5
2012	$ 23.1	$ 2.4
2013	$ 23.1	$ 2.4
2014	$ 23.6	$ 2.3
2015	$ 24.0	$ 2.1
2016 - 2020	$ 122.9	$ 8.8

We expect to make contributions of $0.4 million to our SERP in 2011 to cover benefit payments. Additionally, we are considering making discretionary contributions of up to $40.0 million to our defined benefit pension plan during 2011. We also expect to contribute $2.5 million to our other postretirement benefit plans in 2011 to cover benefit payments.

The Pension Protection Act (the Act) of 2006 contained new requirements for our single employer defined benefit pension plan. In addition to establishing a 100% funding target for plan years beginning after December 31, 2008, the Act also limits some benefits if the funded status of pension plans drops below certain thresholds. Among other restrictions under the Act, if the funded status of a plan falls below a predetermined ratio of 80%, lump-sum payments to new retirees are limited to 50% of amounts that otherwise would have been paid and new benefit improvements may not go into effect. For the 2010 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 99.4% and is estimated to be 99.4% until the 2011 status is certified in September 2011 for the 2011 plan year. The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, grants plan sponsors certain relief from funding requirements and benefit restrictions of the Act.

Plan Assets

Plan assets are invested using a total return investment approach whereby a mix of equity securities, debt securities and other investments are used to preserve asset values, diversify risk and achieve our target investment return benchmark. Investment strategies and asset allocations are based on careful consideration of plan liabilities, the plan's funded status and our financial condition. Investment performance and asset allocation are measured and monitored on an ongoing basis.

Plan assets are managed in a balanced portfolio comprised of two major components: an equity portion and a fixed income portion. The expected role of Plan equity investments is to maximize the long-term real growth of Plan assets, while the role of fixed income investments is to generate current income, provide for more stable periodic returns and provide some protection against a prolonged decline in the market value of Plan equity investments. Long-term strategic asset allocation guidelines are determined by management and take into account the Plan's long-term objectives as well as its short-term constraints. The target allocations for plan assets are 30-80% for equity securities, 30-65% for fixed income securities, 0-10% for cash and 0-25% for alternative investments. Equity securities include U.S. and international equity, while fixed income securities include long-duration and high-yield bond funds and emerging market debt funds. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

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The fair values of our pension plan assets at December 31, 2010 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2010

Asset Category $ in millions		Market Value at 12/31/10		Quoted Prices in Active Markets for Identical Assets (Level 1)		Significant Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)
Equity Securities (a)								
Small/Mid Cap Equity	$	15.2	$	—	$	15.2	$	—
Large Cap Equity		49.4		—		49.4		—
DPL Inc. Common Stock		23.8		23.8		—		—
International Equity		31.5		—		31.5		—
Total Equity Securities	$	119.9	$	23.8	$	96.1	$	—
Debt Securities (b)								
Emerging Markets Debt	$	5.2	$	—	$	5.2	$	—
Fixed Income		39.0		—		39.0		
High Yield Bond		8.2		—		8.2		—
Long Duration Fund		58.9		—		58.9		—
Total Debt Securities	$	111.3	$	—	$	111.3	$	—
Cash and Cash Equivalents (c)								
Cash	$	0.4	$	0.4	$	—	$	—
Other Investments (d)								
Limited Partnership Interest	$	2.8	$	—	$	—	$	2.8
Common Collective Fund		57.4		—		—		57.4
Total Other Investments	$	60.2	$	—	$	—	$	60.2
Total Pension Plan Assets	$	**291.8**	$	**24.2**	$	**207.4**	$	**60.2**

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund except for the **DPL** common stock which is valued using the closing price on the New York Stock Exchange.

(b) This category includes investments in investment-grade fixed-income instruments, U.S. dollar-denominated debt securities of emerging market issuers and high yield fixed-income securities that are rated below investment grade. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(c) This category comprises cash held to pay beneficiaries. The fair value of cash equals its book value.

(d) This category represents a private equity fund that specializes in management buyouts and a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. The fair value of the private equity fund is determined by the General Partner based on the performance of the individual companies. The fair value of the hedge fund is valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

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The fair values of our pension plan assets at December 31, 2009 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2009

Asset Category $ in millions	Market Value at 12/31/09	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Equity Securities (a)				
Small/Mid Cap Equity	$ 4.5	$ —	$ 4.5	$ —
Large Cap Equity	35.9	—	35.9	—
DPL Inc. Common Stock	25.5	25.5	—	—
International Equity	19.2	—	19.2	—
Total Equity Securities	$ 85.1	$ 25.5	$ 59.6	$ —
Debt Securities (b)				
Emerging Markets Debt	$ 12.9	$ —	$ 12.9	$ —
High Yield Bond	13.8	—	13.8	—
Long Duration Fund	77.4	—	77.4	—
Total Debt Securities	$ 104.1	$ —	$ 104.1	$ —
Cash and Cash Equivalents (c)				
Cash	$ 0.5	$ 0.5	$ —	$ —
Other Investments (d)				
Limited Partnership Interest	$ 3.1	$ —	$ —	$ 3.1
Common Collective Fund	50.6	—	—	50.6
Total Other Investments	$ 53.7	$ —	$ —	$ 53.7
Total Pension Plan Assets	$ 243.4	$ 26.0	$ 163.7	$ 53.7

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund except for the **DPL** common stock which is valued using the closing price on the New York Stock Exchange.

(b) This category includes investments in investment-grade fixed-income instruments, U.S. dollar-denominated debt securities of emerging market issuers and high yield fixed-income securities that are rated below investment grade. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(c) This category comprises cash held to pay beneficiaries. The fair value of cash equals its book value.

(d) This category represents a private equity fund that specializes in management buyouts and a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. The fair value of the private equity fund is determined by the General Partner based on the performance of the individual companies. The fair value of the hedge fund is valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

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The change in the fair value for the pension assets valued using significant unobservable inputs (Level 3) was due to the following:

Fair Value Measurements of Pension Assets Using Significant Unobservable Inputs (Level 3)

$ in millions	Limited Partnership Interest	Common Collective Fund
Beginning balance at December 31, 2008	$ 3.1	$ 33.1
Actual return on plan assets:		
Relating to assets still held at the reporting date	0.1	1.3
Relating to assets sold during the period	—	—
Purchases, sales, and settlements	(0.1)	16.2
Transfers in and / or out of Level 3	—	—
Ending balance at December 31, 2009	$ 3.1	$ 50.6
Actual return on plan assets:		
Relating to assets still held at the reporting date	$ 0.1	$ 0.8
Relating to assets sold during the period	—	—
Purchases, sales, and settlements	(0.4)	6.0
Transfers in and / or out of Level 3	—	—
Ending balance at December 31, 2010	$ 2.8	$ 57.4

The fair values of our other postretirement benefit plan assets at December 31, 2010 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2010

Asset Category $ in millions	Market Value at 12/31/10	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
JP Morgan Core Bond Fund (a)	$ 4.8	$ —	$ 4.8	$ —

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

The fair values of our other postretirement benefit plan assets at December 31, 2009 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2009

Asset Category $ in millions	Market Value at 12/31/09	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
JP Morgan Core Bond Fund (a)	$ 5.0	$ —	$ 5.0	$ —

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

8. Fair Value Measurements

The fair values of our financial instruments are based on published sources for pricing when possible. We rely on valuation models only when no other method is available to us. The fair value of our financial instruments represents estimates of possible value that may or may not be realized in the future. The table below presents the fair value and cost of our non-derivative instruments at December 31, 2010 and 2009. See also Note 9 of Notes to Consolidated Financial Statements for the fair values of our derivative instruments.

	At December 31, 2010		At December 31, 2009	
$ in millions	Cost	Fair Value	Cost	Fair Value
DPL				
Assets				
Money Market Funds	$ 1.6	$ 1.6	$ 4.1	$ 4.1
Equity Securities	3.8	4.4	2.6	2.8
Debt Securities	5.2	5.5	5.3	5.5
Multi-Strategy Fund	0.3	0.3	0.3	0.2
Total Master Trust Assets	$ 10.9	$ 11.8	$ 12.3	$ 12.6
Short-term Investments - VRDNs	$ 54.2	$ 54.2	$ —	$ —
Short-term Investments - Bonds	15.1	15.1	—	—
Total Short-term Investments	$ 69.3	$ 69.3	$ —	$ —
Total Assets	$ 80.2	$ 81.1	$ 12.3	$ 12.6
Liabilities				
Debt	$ 1,324.1	$ 1,307.5	$ 1,324.1	$ 1,317.6
DP&L				
Assets				
Money Market Funds	$ 1.6	$ 1.6	$ 4.1	$ 4.1
Equity Securities (a)	17.5	30.2	16.7	31.1
Debt Securities	5.2	5.5	5.3	5.5
Multi-Strategy Fund	0.3	0.3	0.3	0.2
Total Master Trust Assets	$ 24.6	$ 37.6	$ 26.4	$ 40.9
Liabilities				
Debt	$ 884.1	$ 850.6	$ 884.3	$ 844.5

(a)DPL stock held in the DP&L Master Trust is eliminated in consolidation.

Debt

The fair value of debt is based on current public market prices for disclosure purposes only. Unrealized gains or losses are not recognized in the financial statements as debt is presented at amortized cost in the financial statements. The debt amounts include the current portion payable in the next twelve months and have maturities that range from 2011 to 2040.

Master Trust Assets

DP&L established a Master Trust to hold assets for the benefit of employees participating in employee benefit plans and these assets are not used for general operating purposes. These assets are primarily comprised of open-ended mutual funds and **DPL** common stock. The **DPL** common stock held by the **DP&L** Master Trust is eliminated in consolidation and is not reflected in **DPL's** Consolidated Balance Sheets. The **DPL** common stock is valued using current public market prices, while the open-ended mutual funds are valued using the net asset value per unit. These investments are recorded at fair value within Other assets on the balance sheets and classified as available for sale. Any unrealized gains or losses are recorded in AOCI until the securities are sold.

DPL had $0.9 million ($0.6 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2010 and $0.3 million ($0.2 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2009.

DP&L had $13.0 million ($8.5 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2010 and $14.5 million ($9.5 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2009.

Approximately $1.0 million in unrealized gains are expected to be transferred to earnings in the next twelve months.

Short-term Investments

DPL utilizes VRDNs as part of its short-term investment strategy. The VRDNs are of high credit quality and are secured by irrevocable letters of credit from major financial institutions. VRDN investments have variable rates tied to short-term interest rates. Interest rates are reset every seven days and these VRDNs can be tendered for sale upon notice back to the financial institution. Although **DPL's** VRDN investments have original maturities over one year, they are frequently re-priced and trade at par. We account for these VRDNs as available-for-sale securities and record them as short-term investments at fair value, which approximates cost, since they are highly liquid and are readily available to support **DPL's** current operating needs.

DPL also holds investment-grade fixed income corporate bonds that are classified as held-to-maturity. Held-to-maturity securities are those securities that we have the intent and ability to hold until maturity. The held-to-maturity securities are carried at amortized cost which is determined based on specific identification. The bonds are classified as short-term since they will mature within the next twelve months.

Net Asset Value (NAV) per Unit

The following table discloses the fair value and redemption frequency for those assets whose fair value is estimated using the NAV per unit as of December 31, 2010. These assets are part of the Master Trust and exclude **DPL** common stock which is valued using quoted market prices and not the NAV per unit. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of December 31, 2010, **DPL** did not have any investments for sale at a price different from the NAV per unit.

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	Fair Value at December 31, 2010	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Money Market Fund (a)	$ 1.6	$ —	Immediate	None
Equity Securities (b)	4.4	—	Immediate	None
Debt Securities (c)	5.5	—	Immediate	None
Multi-Strategy Fund (d)	0.3	—	Immediate	None
Total	$ 11.8	$ —		

(a) This category includes investments in high-quality, short-term securities. Investments in this category can be redeemed immediately at the current net asset value per unit.

(b) This category includes investments in hedge funds representing an S&P 500 index and the Morgan Stanley Capital International (MSCI) U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current net asset value per unit.

(c) This category includes investments in U.S. Treasury obligations and U.S. investment grade bonds. Investments in this category can be redeemed immediately at the current net asset value per unit.

(d) This category includes investments in stocks, bonds and short-term investments in a mix of actively managed funds. Investments in this category can be redeemed immediately at the current net asset value per unit.

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	Fair Value at December 31, 2009	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
Money Market Fund (a)	$ 4.1	$ —	Immediate	None
Equity Securities (b)	2.8	—	Immediate	None
Debt Securities (c)	5.5	—	Immediate	None
Multi-Strategy Fund (d)	0.2	—	Immediate	None
Total	$ 12.6	$ —		

(a) This category includes investments in high-quality, short-term securities. Investments in this category can be redeemed immediately at the current net asset value per unit.

(b) This category includes investments in hedge funds representing an S&P 500 index and the Morgan Stanley Capital International (MSCI) U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current net asset value per unit.

(c) This category includes investments in U.S. Treasury obligations and U.S. investment grade bonds. Investments in this category can be redeemed immediately at the current net asset value per unit.

(d) This category includes investments in stocks, bonds and short-term investments in a mix of actively managed funds. Investments in this category can be redeemed immediately at the current net asset value per unit.

Fair Value Hierarchy

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. These inputs are then categorized as Level 1 (quoted prices in active markets for identical assets or liabilities); Level 2 (observable inputs such as quoted prices for similar assets or liabilities or quoted prices in markets that are not active); or Level 3 (unobservable inputs).

Valuations of assets and liabilities reflect the value of the instrument including the values associated with counterparty risk. We include our own credit risk and our counterparty's credit risk in our calculation of fair value using global average default rates based on an annual study conducted by a large rating agency.

We did not have any transfers of the fair values of our financial instruments between Level 1 and Level 2 of the fair value hierarchy during the twelve months ended December 31, 2010 and 2009. The fair value of assets and liabilities at December 31, 2010 and 2009 measured on a recurring basis and the respective category within the fair value hierarchy for **DPL** was determined as follows:

DPL

$ in millions	Fair Value at December 31, 2010*	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2010
	Assets and Liabilities Measured at Fair Value on a Recurring Basis					
Assets						
Master Trust Assets						
Money Market Funds	$ 1.6	$ —	$ 1.6	$ —	$ —	$ 1.6
Equity Securities	4.4	—	4.4	—	—	4.4
Debt Securities	5.5	—	5.5	—	—	5.5
Multi-Strategy Fund	0.3	—	0.3	—	—	0.3
Total Master Trust Assets	$ 11.8	$ —	$ 11.8	$ —	$ —	$ 11.8
Derivative Assets						
FTRs	$ 0.3	$ —	$ 0.3	$ —	$ —	$ 0.3
Heating Oil Futures	1.6	1.6	—	—	(1.6)	—
Interest Rate Hedge	20.7	—	20.7	—	—	20.7
Forward NYMEX Coal Contracts	37.5	—	37.5	—	(21.9)	15.6
Forward Power Contracts	0.2	—	0.2	—	(0.2)	—
Total Derivative Assets	$ 60.3	$ 1.6	$ 58.7	$ —	$ (23.7)	$ 36.6
Short-term Investments - VRDNs	$ 54.2	$ —	$ 54.2	$ —	$ —	$ 54.2
Short-term Investments - Bonds	15.1	—	15.1	—	—	15.1
Total Short-term investments	$ 69.3	$ —	$ 69.3	$ —	$ —	$ 69.3
Total Assets	$ 141.4	$ 1.6	$ 139.8	$ —	$ (23.7)	$ 117.7
Liabilities						
Derivative Liabilities						
Interest Rate Hedge	$ 6.6	$ —	$ 6.6	$ —	$ —	$ 6.6
Forward Power Contracts	3.1	—	3.1	—	(1.1)	2.0
Total Derivative Liabilities	$ 9.7	$ —	$ 9.7	$ —	$ (1.1)	$ 8.6
Total Liabilities	$ 9.7	$ —	$ 9.7	$ —	$ (1.1)	$ 8.6

*Includes credit valuation adjustments for counterparty risk.

DPL

$ in millions	Fair Value at December 31, 2009*	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2009
	Assets and Liabilities Measured at Fair Value on a Recurring Basis					
Assets						
Master Trust Assets						
Money Market Funds	$ 4.1	$ —	$ 4.1	$ —	$ —	$ 4.1
Equity Securities	2.8	—	2.8	—	—	2.8
Debt Securities	5.5	—	5.5	—	—	5.5
Multi-Strategy Fund	0.2	—	0.2	—	—	0.2

Total Master Trust Assets	$ 12.6	$ —	$ 12.6	$ —	$ —	$ 12.6
Derivative Assets						
FTRs	$ 0.8	$ —	$ 0.8	$ —	$ —	$ 0.8
Forward NYMEX Coal Contracts	5.5	—	5.5	—	(1.4)	4.1
Forward Power Contracts	0.7	—	0.7	—	(0.7)	—
Total Derivative Assets	$ 7.0	$ —	$ 7.0	$ —	$ (2.1)	$ 4.9
Total Assets	$ 19.6	$ —	$ 19.6	$ —	$ (2.1)	$ 17.5
Liabilities						
Derivative Liabilities						
Heating Oil Futures	$ 1.2	$ 1.2	$ —	$ —	$ (1.2)	$ —
Forward Power Contracts	3.0	—	3.0	—	(0.7)	2.3
Forward NYMEX Coal Contracts	1.2	—	1.2	—	—	1.2
Total Derivative Liabilities	$ 5.4	$ 1.2	$ 4.2	$ —	$ (1.9)	$ 3.5
Total Liabilities	$ 5.4	$ 1.2	$ 4.2	$ —	$ (1.9)	$ 3.5

*Includes credit valuation adjustments for counterparty risk.

The fair value of assets and liabilities at December 31, 2010 and 2009 measured on a recurring basis and the respective category within the fair value hierarchy for **DP&L** was determined as follows:

DP&L

$ in millions	Fair Value at December 31, 2010*	Level 1: Based on Quoted Prices in Active Markets	Level 2: Other Observable Inputs	Level 3: Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2010
Assets						
Master Trust Assets						
Money Market Funds	$ 1.6	$ —	$ 1.6	$ —	$ —	$ 1.6
Equity Securities (a)	30.2	25.8	4.4	—	—	30.2
Debt Securities	5.5	—	5.5	—	—	5.5
Multi-Strategy Fund	0.3	—	0.3	—	—	0.3
Total Master Trust Assets	$ 37.6	$ 25.8	$ 11.8	$ —	$ —	$ 37.6
Derivative Assets						
FTRs	$ 0.3	$ —	$ 0.3	$ —	$ —	$ 0.3
Heating Oil Futures	1.6	1.6	—	—	(1.6)	—
Forward NYMEX Coal Contracts	37.5	—	37.5	—	(21.9)	15.6
Forward Power Contracts	0.2	—	0.2	—	(0.2)	—
Total Derivative Assets	$ 39.6	$ 1.6	$ 38.0	$ —	$ (23.7)	$ 15.9
Total Assets	$ 77.2	$ 27.4	$ 49.8	$ —	$ (23.7)	$ 53.5
Liabilities						
Derivative Liabilities						
Heating Oil Futures	$ —	$ —	$ —	$ —	$ —	$ —
Forward Power Contracts	3.1	—	3.1	—	(1.1)	2.0
Forward NYMEX Coal Contracts	—	—	—	—	—	—
Total Derivative Liabilities	$ 3.1	$ —	$ 3.1	$ —	$ (1.1)	$ 2.0
Total Liabilities	$ 3.1	$ —	$ 3.1	$ —	$ (1.1)	$ 2.0

*Includes credit valuation adjustments for counterparty risk.

(a) **DPL** stock in the Master Trust is eliminated in consolidation.

DP&L

$ in millions	Fair Value at December 31, 2009*	Level 1: Based on Quoted Prices in Active Markets	Level 2: Other Observable Inputs	Level 3: Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2009
Assets						
Master Trust Assets						
Money Market Funds	$ 4.1	$ —	$ 4.1	$ —	$ —	$ 4.1
Equity Securities (a)	31.1	28.3	2.8	—	—	31.1
Debt Securities	5.5	—	5.5	—	—	5.5
Multi-Strategy Fund	0.2	—	0.2	—	—	0.2
Total Master Trust Assets	$ 40.9	$ 28.3	$ 12.6	$ —	$ —	$ 40.9
Derivative Assets						

FTRs	$ 0.8	$ —	$ 0.8	$ —	$ —	$ 0.8
Forward NYMEX Coal Contracts	5.5	—	5.5	—	(1.4)	4.1
Forward Power Contracts	0.7	—	0.7	—	(0.7)	—
Total Derivative Assets	$ 7.0	$ —	$ 7.0	$ —	$ (2.1)	$ 4.9
Total Assets	$ 47.9	$ 28.3	$ 19.6	$ —	$ (2.1)	$ 45.8
Liabilities						
Derivative Liabilities						
Heating Oil Futures	$ 1.2	$ 1.2	$ —	$ —	$ (1.2)	$ —
Forward Power Contracts	3.0	—	3.0	—	(0.7)	2.3
Forward NYMEX Coal Contracts	1.2	—	1.2	—	—	1.2
Total Derivative Liabilities	$ 5.4	$ 1.2	$ 4.2	$ —	$ (1.9)	$ 3.5
Total Liabilities	$ 5.4	$ 1.2	$ 4.2	$ —	$ (1.9)	$ 3.5

*Includes credit valuation adjustments for counterparty risk.

(a) **DPL** stock in the Master Trust is eliminated in consolidation.

We use the market approach to value our financial instruments. Level 1 inputs are used for **DPL** common stock held by the Master Trust and for derivative contracts such as heating oil futures and natural gas futures. The fair value is determined by reference to quoted market prices and other relevant information generated by market transactions. Level 2 inputs are used to value derivatives such as financial transmission rights (where the quoted prices are from a relatively inactive market), forward power contracts and forward NYMEX-quality coal contracts (which are traded on the OTC market but which are valued using prices on the NYMEX for similar contracts on the OTC market). VRDNs and bonds are considered Level 2 because they are priced using recent transactions for similar assets. Other Level 2 assets include: open-ended mutual funds that are in the Master Trust, which are valued using the end of day NAV per unit, and interest rate hedges, which use observable inputs to populate a pricing model.

Approximately 99% of the inputs to the fair value of our derivative instruments are from quoted market prices.

Non-recurring Fair Value Measurements

We use the cost approach to determine the fair value of our AROs which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. There were $1.4 million and $2.7 million of gross additions to our existing landfill and asbestos AROs during the twelve months ended December 31, 2010 and 2009. In addition, it was determined that a river structure would be retired earlier than previously estimated. This resulted in a partial reduction to the ARO liability of $0.8 million in 2010.

Cash Equivalents

DPL had $29.9 million and $45.3 million in money market funds classified as cash and cash equivalents in its Consolidated Balance Sheets at December 31, 2010 and 2009, respectively. The money market funds have quoted prices that are generally equivalent to par.

9. Derivative Instruments and Hedging Activities

In the normal course of business, **DPL** and **DP&L** enter into various financial instruments, including derivative financial instruments. We use derivatives principally to manage the risk of changes in market prices for commodities and interest rate risk associated with our long-term debt. The derivatives that we use to economically hedge these risks are governed by our risk management policies for forward and futures contracts. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The objective of the hedging program is to mitigate financial risks while ensuring that we have adequate resources to meet our requirements. We monitor and value derivative positions monthly as part of our risk management processes. We use published sources for pricing, when possible, to mark positions to market. All of our derivative instruments are used for risk management purposes and are designated as cash flow hedges or marked to market each reporting period.

At December 31, 2010, **DPL** and **DP&L** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs (1)	Mark to Market	MWh	9.0	—	9.0
Heating Oil Futures (1)	Mark to Market	Gallons	6,216.0	—	6,216.0
Forward Power Contracts (1)	Cash Flow Hedge	MWh	580.8	(572.9)	7.9
Forward Power Contracts (1)	Mark to Market	MWh	195.6	(108.5)	87.1
NYMEX-quality Coal Contracts* (1)	Mark to Market	Tons	4,006.8	—	4,006.8
Interest Rate Swaps (2)	Cash Flow Hedge	USD	360,000.0	—	360,000.0

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

(1) Reflected in both DPL's and DP&L's financial statements

(2) Reflected in only DPL's financial statements

At December 31, 2009, both **DPL** and **DP&L** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchase/ (Sale) (in thousands)
FTRs	Mark to Market	MWH	9.3	—	9.3
Heating Oil Futures	Mark to Market	Gallons	3,822.0	—	3,822.0
Forward Power Contracts	Cash Flow Hedge	MWH	84.6	(1,769.2)	(1,684.6)
NYMEX-quality Coal Contracts*	Mark to Market	Tons	3,844.0	(1,286.5)	2,557.5

*Includes our partner's share for the jointly-owned plants that **DP&L** operates.

Cash Flow Hedges

As part of our risk management processes, we identify the relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking various hedge transactions. The fair value of cash flow hedges as determined by current public market prices will continue to fluctuate with changes in market prices up to contract expiration. The effective portion of the hedging transaction is recognized in AOCI and transferred to earnings using specific identification of each contract when the forecasted hedged transaction takes place or when the forecasted hedged transaction is probable of not occurring. The ineffective portion of the cash flow hedge is recognized in earnings in the current period. All risk components were taken into account to determine the hedge effectiveness of the cash flow hedges.

We enter into forward power contracts to manage commodity price risk exposure related to our generation of electricity. We do not hedge all commodity price risk. We reclassify gains and losses on forward power contracts from AOCI into earnings in those periods in which the contracts settle.

We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated 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. We do not hedge all interest rate exposure. As of December 31, 2010, we have entered into interest rate hedging relationships with aggregate notional amounts of $200 million and $160 million related to planned future borrowing activities in calendar years 2011 and 2013, respectively. We reclassify gains and losses on interest rate derivative hedges related to our debt financings from AOCI into earnings in those periods in which hedged interest payments occur.

The following table provides information for **DPL** concerning gains or losses recognized in AOCI for the cash flow hedges:

$ in millions (net of tax)	December 31, 2010		December 31, 2009		December 31, 2008	
	Power	Interest Rate Hedge	Power	Interest Rate Hedge	Power and Capacity	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	$ (1.4)	$ 14.7	$ (0.2)	$ 17.2	$ (1.0)	$ 19.7
Net gains / (losses) associated with current period hedging transactions	3.1	9.2	2.2	—	4.8	—
Net gains reclassified to earnings						
Interest Expense	—	(2.5)	—	(2.5)	—	(2.5)
Revenues	(3.5)	—	(3.4)	—	(4.0)	—
Ending accumulated derivative gain / (loss) in AOCI	$ (1.8)	$ 21.4	$ (1.4)	$ 14.7	$ (0.2)	$ 17.2
Net gains / (losses) associated with the ineffective portion of the hedging transaction:						
Interest expense	$ —	$ —	$ —	$ —	$ —	$ —
Revenues	$ —	$ —	$ —	$ —	$ —	$ —
Portion expected to be reclassified to earnings in the next twelve months*	$ (2.8)	$ 2.5				
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	36	33				

*The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

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The following table provides information for **DP&L** concerning gains or losses recognized in AOCI for the cash flow hedges:

$ in millions (net of tax)	December 31, 2010 Power	December 31, 2010 Interest Rate Hedge	December 31, 2009 Power	December 31, 2009 Interest Rate Hedge	December 31, 2008 Power and Capacity	December 31, 2008 Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	$ (1.4)	$ 14.7	$ (0.2)	$ 17.2	$ (1.0)	$ 19.7
Net gains / (losses) associated with current period hedging transactions	3.1	—	2.2	—	4.8	—
Net gains reclassified to earnings						
Interest Expense	—	(2.5)	—	(2.5)	—	(2.5)
Revenues	(3.5)	—	(3.4)	—	(4.0)	—
Ending accumulated derivative gain / (loss) in AOCI	$ (1.8)	$ 12.2	$ (1.4)	$ 14.7	$ (0.2)	$ 17.2
Net gains / (losses) associated with the ineffective portion of the hedging transaction:						
Interest expense	$ —	$ —	$ —	$ —	$ —	$ —
Revenues	$ —	$ —	$ —	$ —	$ —	$ —
Portion expected to be reclassified to earnings in the next twelve months*	$ (2.8)	$ —				
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	36	—				

*The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

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The following table shows the fair value and balance sheet classification of **DPL's** derivative instruments designated as hedging instruments at December 31, 2010.

Fair Values of Derivative Instruments Designated as Hedging Instruments

at December 31, 2010

DPL

$ in millions	Fair Value(1)	Netting(2)	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in a Liability Position	$ (2.8)	$ 1.0	Other current liabilities	$ (1.8)
Interest Rate Hedges in a Liability Position	(6.6)	—	Other current liabilities	(6.6)
Total short-term cash flow hedges	$ (9.4)	$ 1.0		$ (8.4)
Long-term Derivative Positions				
Forward Power Contracts in an Asset Position	$ 0.2	$ (0.2)	Other deferred assets	$ —
Forward Power Contracts in a Liability Position	(0.2)	0.1	Other deferred credits	(0.1)
Interest Rate Hedges in an Asset Position	20.7	—	Other deferred credits	20.7
Total long-term cash flow hedges	$ 20.7	$ (0.1)		$ 20.6
Total cash flow hedges	$ 11.3	$ 0.9		$ 12.2

(1) Includes credit valuation adjustment.

(2) Includes counterparty and collateral netting.

The following table shows the fair value and balance sheet classification of **DP&L's** derivative instruments designated as hedging instruments at December 31, 2010.

Fair Values of Derivative Instruments Designated as Hedging Instruments

at December 31, 2010

DP&L

$ in millions	Fair Value(1)	Netting(2)	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in a Liability Position	$ (2.8)	$ 1.0	Other current liabilities	$ (1.8)
Total short-term cash flow hedges	$ (2.8)	$ 1.0		$ (1.8)
Long-term Derivative Positions				
Forward Power Contracts in an Asset Position	$ 0.2	$ (0.2)	Other deferred assets	$ —
Forward Power Contracts in a Liability Position	(0.2)	0.1	Other deferred credits	(0.1)

Total long-term cash flow hedges	$ —	$ (0.1)	$ (0.1)
Total cash flow hedges	$ (2.8)	$ 0.9	$ (1.9)

(1) Includes credit valuation adjustment.

(2) Includes counterparty and collateral netting.

The following table shows the fair value and balance sheet classification of **DPL's** and **DP&L's** derivative instruments designated as hedging instruments at December 31, 2009.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2009

$ in millions	Fair Value(1)	Netting(2)	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in an Asset Position	$ 0.7	$ (0.7)	Other prepayments and current assets	$ —
Forward Power Contracts in a Liability Position	(2.8)	0.7	Other current liabilities	(2.1)
Total cash flow hedges	$ (2.1)	$ —		$ (2.1)

(1) Includes credit valuation adjustment

(2) Includes counterparty and collateral netting.

Mark to Market Accounting

Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for hedge accounting or the normal purchases and sales exceptions under FASC Topic 815. Accordingly, such contracts are recorded at fair value with changes in the fair value charged or credited to the consolidated statements of results of operations in the period in which the change occurred. This is commonly referred to as "MTM accounting." Contracts we enter into as part of our risk management program may be settled financially, by physical delivery or net settled with the counterparty. We mark to market FTRs, heating oil futures, forward NYMEX-quality coal contracts, natural gas futures and certain forward power contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided under GAAP. Derivative contracts that have been designated as normal purchases or normal sales under GAAP are not subject to MTM accounting treatment and are recognized in the consolidated statements of results of operations on an accrual basis.

Regulatory Assets and Liabilities

In accordance with regulatory accounting under GAAP, a cost that is probable of recovery in future rates should be deferred as a regulatory asset and a gain that is probable of being returned to customers should be deferred as a regulatory liability. Portions of the derivative contracts that are marked to market each reporting period and are related to the retail portion of **DP&L's** load requirements are included as part of the fuel and purchased power recovery rider approved by the PUCO which began January 1, 2010. Therefore, the Ohio retail customers' portion of the heating oil futures and the NYMEX-quality coal contracts are deferred as a regulatory asset or liability until the contracts settle. If these unrealized gains and losses are no longer deemed to be probable of recovery through our rates, they will be reclassified into earnings in the period such determination is made.

The following tables show the amount and classification within the consolidated statements of results of operations or balance sheets of the gains and losses on **DPL's** and **DP&L's** derivatives not designated as hedging instruments for the twelve months ended December 31, 2010 and 2009.

For the Twelve Months Ended December 31, 2010

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 33.5	$ 2.8	$ (0.6)	$ 0.1	$ 35.8
Realized gain / (loss)	3.2	(1.6)	(1.5)	(0.1)	—
Total	$ 36.7	$ 1.2	$ (2.1)	$ —	$ 35.8
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 20.1	$ —	$ —	$ —	$ 20.1
Regulatory (asset) / liability	4.6	1.1	—	—	5.7
Recorded in Income Statement: gain / (loss)					
Purchased power	$ —	$ —	$ (2.1)	$ —	$ (2.1)
Fuel	12.0	0.1	—	—	12.1
O&M	—	—	—	—	—
Total	$ 36.7	$ 1.2	$ (2.1)	$ —	$ 35.8

For the Twelve Months Ended December 31, 2009

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 4.1	$ 5.1	$ 0.8	$ (0.2)	$ 9.8
Realized gain / (loss)	1.1	(3.1)	(0.4)	—	(2.4)
Total	$ 5.2	$ 2.0	$ 0.4	$ (0.2)	$ 7.4
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 1.8	$ —	$ —	$ —	$ 1.8
Regulatory (asset) / liability	1.5	(0.5)	—	—	1.0
Recorded in Income Statement: gain / (loss)					
Purchased power	$ —	$ —	$ 0.4	$ (0.2)	$ 0.2
Fuel	1.9	2.3	—	—	4.2
O&M	—	0.2	—	—	0.2
Total	$ 5.2	$ 2.0	$ 0.4	$ (0.2)	$ 7.4

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The following tables show the fair value and balance sheet classification of **DPL**'s and **DP&L**'s derivative instruments not designated as hedging instruments at December 31, 2010 and 2009.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments

at December 31, 2010

$ in millions	Fair Value(1)	Netting(2)	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.3	$ —	Other prepayments and current assets	$ 0.3
Forward Power Contracts in a Liability position	(0.1)	—	Other current liabilities	(0.1)
NYMEX-Quality Coal Forwards in an Asset position	14.0	(7.4)	Other prepayments and current assets	6.6
Heating Oil Futures in an Asset position	0.5	(0.5)	Other current liabllities	—
Total short-term derivative MTM positions	$ 14.7	$ (7.9)		$ 6.8
Long-term Derivative Positions				
NYMEX-Quality Coal Forwards in an Asset position	$ 23.5	$ (14.5)	Other deferred assets	$ 9.0
Heating Oil Futures in an Asset position	1.1	(1.1)	Other deferred credits	—
Total long-term derivative MTM positions	$ 24.6	$ (15.6)		$ 9.0
Total MTM Position	$ 39.3	$ (23.5)		$ 15.8

(1) Includes credit valuation adjustment

(2) Includes counterparty and collateral netting.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at December 31, 2009

$ in millions	Fair Value(1)	Netting(2)	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.8	$ —	Other prepayments and current assets	$ 0.8
NYMEX-Quality Coal Forwards in an Asset position	2.4	—	Other prepayments and current assets	2.4
NYMEX-Quality Coal Forwards in a Liability position	(1.2)	—	Other current liabilities	(1.2)
Heating Oil Futures in a Liability position	(1.2)	1.2	Other current liabllities	—
Forward Power Contracts in a Liability position	(0.2)	—	Other current liabilities	(0.2)
Total short-term derivative MTM positions	$ 0.6	$ 1.2		$ 1.8
Long-term Derivative Positions				
NYMEX-Quality Coal Forwards in an	$ 2.9	$ (1.2)	Other deferred	$ 1.7

Asset position			assets	
Total long-term derivative MTM positions	$ 2.9	$ (1.2)		$ 1.7
Total MTM Position	$ 3.5	$ —		$ 3.5

(1) Includes credit valuation adjustment

(2) Includes counterparty and collateral netting.

Certain of our OTC commodity derivative contracts are under master netting agreements that contain provisions that require our debt to maintain an investment grade credit rating from credit rating agencies. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization of the MTM loss. The aggregate fair value of all commodity derivative instruments that are in a MTM loss position at December 31, 2010 is $3.1 million. This amount is offset by $1.0 million in a broker margin account which offsets our loss positions on the NYMEX Clearport traded forward power contracts. This liability position is further offset by the asset position of counterparties with master netting agreements of $0.2 million. If our debt were to fall below investment grade, we may have to post collateral for the remaining $1.9 million.

10. Share-Based Compensation

In April 2006, **DPL's** shareholders approved The DPL Inc. Equity and Performance Incentive Plan (the EPIP) which became immediately effective and will remain in effect for a term of ten years, unless terminated sooner in accordance with its terms. The Compensation Committee of the Board of Directors will designate the employees and directors eligible to participate in the EPIP and the times and types of awards to be granted. Under the EPIP, the Compensation Committee may grant equity-based compensation in the form of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and units, and other stock-based awards. Awards may be subject to the achievement of certain management objectives. In addition, the EPIP provides, upon recommendation of the Chief Executive Officer or Chairman of the Board, for a grant of a special equity award to recognize outstanding performance. A total of 4,500,000 shares of **DPL** common stock were reserved for issuance under the EPIP.

The following table summarizes share-based compensation expense recorded at **DPL** and **DP&L**:

	For the years ended December 31,		
$ in millions	**2010**	**2009**	**2008**
Restricted stock units	$ —	$ —	$ (0.1)
Performance shares	2.1	1.8	0.9
Restricted shares	1.7	0.7	0.3
Non-employee directors' RSUs	0.4	0.5	0.5
Management performance shares	0.5	0.7	0.3
Share-based compensation included in Operation and maintenance expense	4.7	3.7	1.9
Income tax expense / (benefit)	(1.6)	(1.3)	(0.7)
Total share-based compensation, net of tax	$ 3.1	$ 2.4	$ 1.2

Share-based awards issued in **DPL's** common stock will be distributed from treasury stock. **DPL** has sufficient treasury stock to satisfy all outstanding share-based awards.

Determining Fair Value

Valuation and Amortization Method — We estimate the fair value of stock options and RSUs using a Black-Scholes-Merton model; performance shares are valued using a Monte Carlo simulation; restricted shares are valued at the closing market price on the day of grant and the Directors' RSUs are valued at the closing market price on the day prior to the grant date. We amortize the fair value of all awards on a straight-line basis over the requisite service periods, which are generally the vesting periods.

Expected Volatility — Our expected volatility assumptions are based on the historical volatility of **DPL** common stock. The volatility range captures the high and low volatility values for each award granted based on its specific terms.

Expected Life — The expected life assumption represents the estimated period of time from the grant date until the exercise date and reflects historical employee exercise patterns.

Risk-Free Interest Rate — The risk-free interest rate for the expected term of the award is based on the corresponding yield curve in effect at the time of the valuation for U.S. Treasury bonds having the same term as the expected life of the award, i.e., a five year bond rate is used for valuing an award with a five year expected life.

Expected Dividend Yield — The expected dividend yield is based on **DPL's** current dividend rate, adjusted as necessary to capture anticipated dividend changes and the 12 month average **DPL** common stock price.

Expected Forfeitures — The forfeiture rate used to calculate compensation expense is based on **DPL's** historical experience, adjusted as necessary to reflect special circumstances.

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Stock Options

In 2000, **DPL's** Board of Directors adopted and **DPL's** shareholders approved The DPL Inc. Stock Option Plan. With the approval of the EPIP in April 2006, no new awards will be granted under The DPL Inc. Stock Option Plan but shares relating to awards that are forfeited or terminated under The DPL Inc. Stock Option Plan may be granted under the EPIP. As of December 31, 2010, there were no unvested stock options.

Summarized stock option activity was as follows:

	For the years ended December 31, 2010	2009	2008
Options:			
Outstanding at beginning of year	**417,500**	836,500	946,500
Granted	**—**	—	—
Exercised	**(66,000)**	(419,000)	(110,000)
Forfeited	**—**	—	—
Outstanding at year-end	**351,500**	417,500	836,500
Exercisable at year-end*	**351,500**	417,500	836,500
Weighted average option prices per share:			
Outstanding at beginning of year	**$ 27.16**	$ 24.64	$ 24.09
Granted	**$ —**	$ —	$ —
Exercised	**$ 21.00**	$ 21.53	$ 18.56
Forfeited	**$ —**	$ —	$ —
Outstanding at year-end	**$ 28.04**	$ 27.16	$ 24.64
Exercisable at year-end	**$ 28.04**	$ 27.16	$ 24.64

**251,000 of these stock options expired on January 1, 2011.*

The following table reflects information about stock options outstanding at December 31, 2010:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Outstanding	Weighted-Average Contractual Life (in Years)	Weighted-Average Exercise Price	Exercisable	Weighted-Average Exercise Price
$14.95 - $21.00	75,000	0.3	$ 20.97	75,000	$ 20.97
$21.01 - $29.63	276,500	0.1	$ 29.42	276,500	$ 29.42

The following table reflects information about stock option activity during the period:

$ in millions	For the years ended December 31, 2010	2009	2008
Weighted-average grant date fair value of options granted during the period	$ —	$ —	$ —
Intrinsic value of options exercised during the period	$ **0.5**	$ 2.2	$ 1.0
Proceeds from stock options exercised during the period	$ **1.4**	$ 9.0	$ 2.2
Excess tax benefit from proceeds of stock options exercised	$ **0.1**	$ 0.7	$ 0.3
Fair value of shares that vested during the period	$ —	$ —	$ —
Unrecognized compensation expense	$ —	$ —	$ —
Weighted average period to recognize compensation expense (in years)	—	—	—

No options were granted during 2010, 2009 or 2008.

Restricted Stock Units (RSUs)

RSUs were granted to certain key employees prior to 2001. As of December 31, 2010, there were no RSUs outstanding.

$ in millions	Number of RSUs	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2010	3,311	$ 0.1
Granted in 2010	—	—
Vested in 2010	(3,311)	(0.1)
Forfeited in 2010	—	—
Non-vested at December 31, 2010	—	$ —

Summarized RSU activity was as follows:

	For the years ended December 31,		
	2010	2009	2008
RSUs:			
Outstanding at beginning of year	**3,311**	10,120	22,976
Granted	—	—	—
Dividends	—	—	—
Exercised	**(3,311)**	(6,809)	(11,253)
Forfeited	—	—	(1,603)
Outstanding at period end	—	3,311	10,120
Exercisable at period end	—	—	—

Compensation expense is recognized each quarter based on the change in the market price of **DPL** common stock. As of December 31, 2010, 2009 and 2008, liabilities recorded for outstanding RSUs were zero, $0.1 million and $0.2 million, respectively, which are included in Other deferred credits on the balance sheets.

Performance Shares

Under the EPIP, the Board of Directors adopted a Long-Term Incentive Plan (LTIP) under which **DPL** will grant a targeted number of performance shares of common stock to executives. Grants under the LTIP will be awarded based on a Total Shareholder Return Relative to Peers performance. No performance shares will be earned in a performance period if the three-year Total Shareholder Return Relative to Peers is below the threshold of the 40th percentile. Further, the LTIP awards will be capped at 200% of the target number of performance shares, if the Total Shareholder Return Relative to Peers is at or above the threshold of the 90th percentile. The Total Shareholder Return Relative to Peers is considered a market condition in accordance with the accounting guidance for share-based compensation. There is a three year requisite service period for each portion of the performance shares.

The schedule of non-vested performance share activity for the year ended December 31, 2010 follows:

$ in millions	Number of Performance Shares	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2010	190,349	$ 4.3
Granted in 2010	161,534	2.9
Vested in 2010	(110,734)	(1.6)
Forfeited in 2010	(29,651)	(0.7)
Non-vested at December 31, 2010	211,498	$ 4.9

	For the years ended December 31, 2010	2009	2008
Performance shares:			
Outstanding at beginning of year	**237,704**	156,300	142,108
Granted	**161,534**	124,588	93,298
Exercised	**(91,253)**	—	—
Expired	—	(36,445)	(37,426)
Forfeited	**(29,651)**	(6,739)	(41,680)
Outstanding at period end	**278,334**	237,704	156,300
Exercisable at period end	**66,836**	47,355	36,445

The following table reflects information about performance share activity during the period:

$ in millions	For the years ended December 31, 2010	2009	2008
Weighted-average grant date fair value of performance shares granted during the period	**$ 2.9**	$ 2.8	$ 2.2
Intrinsic value of performance shares exercised during the period	**$ 2.5**	$ —	$ —
Proceeds from performance shares exercised during the period	**$ —**	$ —	$ —
Excess tax benefit from proceeds of performance shares exercised	**$ —**	$ —	$ —
Fair value of performance shares that vested during the period	**$ 1.6**	$ 1.6	$ 0.8
Unrecognized compensation expense	**$ 2.4**	$ 2.1	$ 1.6
Weighted average period to recognize compensation expense (in years)	**1.7**	1.7	1.6

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the performance shares granted during the period:

	For the years ended December 31, 2010	2009	2008
Expected volatility	**24.3%**	22.8% - 23.3%	15.0% - 15.7%
Weighted-average expected volatility	**24.3%**	22.8%	15.1%
Expected life (years)	**3.0**	3.0	3.0
Expected dividends	**4.5%**	5.4% - 5.6%	3.5% - 4.1%
Weighted-average expected dividends	**4.5%**	5.6%	4.1%
Risk-free interest rate	**1.4%**	0.3% - 1.5%	2.2% - 3.2%

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Restricted Shares

Under the EPIP, the Board of Directors have granted shares of **DPL** restricted shares to various executives. The restricted shares are registered in the executive's name, carry full voting privileges, receive dividends as declared and paid on all **DPL** common stock and vest after a specified service period.

In July 2008, the Board of Directors granted restricted stock awards to a select group of management employees. The management restricted stock awards have a three-year requisite service period, carry full voting privileges and receive dividends as declared and paid on all **DPL** common stock.

On September 17, 2009, the Board of Directors approved a two-part equity compensation award under the EPIP for certain of **DPL's** executive officers. The first part is a restricted share grant and the second part is a matching restricted share grant. These restricted shares generally vest after five years if the participant remains continuously employed with **DPL** or a **DPL** subsidiary and if the year over year average basic EPS has increased by at least 1% per year over the five year vesting period. Under the matching restricted share grant, participants will have a three-year period from the date of plan implementation during which they may purchase **DPL** common stock equal in value to up to two times their base salary. **DPL** will match the shares purchased with another grant of restricted stock (matching restricted share grant). The percentage match by **DPL** is detailed in the table below. The matching restricted share grant will generally vest over a three year period if the participant continues to hold the originally purchased shares and remains continuously employed with **DPL** or a subsidiary. The restricted shares are registered in the executive's name, carry full voting privileges and receive dividends as declared and paid on all **DPL** common stock.

The matching criteria are:

Value (Cost Basis) of Shares Purchased as a % of 2009 Base Salary	Company % Match of Shares Purchased
<25%	25%
25% to <50%	50%
50% to <100%	75%
100% to 200%	125%

The matching percentage is applied on a cumulative basis and the resulting restricted shares grant is adjusted at the end of each quarter.

Restricted shares can only be awarded in **DPL** common stock.

$ in millions	Number of Restricted Shares	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2010	218,197	$ 5.8
Granted in 2010	42,977	1.1
Vested in 2010	(20,803)	(0.6)
Forfeited in 2010	(20,980)	(0.6)
Non-vested at December 31, 2010	219,391	$ 5.7

	For the years ended December 31, 2010	2009	2008
Restricted shares:			
Outstanding at beginning of year	**218,197**	69,147	42,200
Granted	**42,977**	159,050	39,347
Exercised	**(20,803)**	(10,000)	(1,000)
Forfeited	**(20,980)**	—	(11,400)
Outstanding at period end	**219,391**	218,197	69,147
Exercisable at period end	**—**	—	—

The following table reflects information about restricted share activity during the period:

$ in millions	For the years ended December 31, 2010	2009	2008
Weighted-average grant date fair value of restricted shares granted during the period	$ **1.1**	$ 4.2	$ 1.1
Intrinsic value of restricted shares exercised during the period	$ **0.4**	$ 0.3	$ —
Proceeds from restricted shares exercised during the period	$ —	$ —	$ —
Excess tax benefit from proceeds of restricted shares exercised	$ **0.1**	$ —	$ —
Fair value of restricted shares that vested during the period	$ **0.6**	$ 0.3	$ —
Unrecognized compensation expense	$ **3.4**	$ 4.3	$ 1.3
Weighted average period to recognize compensation expense (in years)	**2.7**	3.4	2.7

Non-Employee Director Restricted Stock Units

Under the EPIP, as part of their annual compensation for service to **DPL** and **DP&L**, each non-employee Director receives a retainer in RSUs on the date of the annual meeting of shareholders. The RSUs will become non-forfeitable on April 15 of the following year. All of the RSUs become non-forfeitable in the event of death, disability, or change in control; but if the Director resigns or retires prior to the April 15 vesting date, the vested shares will be distributed on a pro rata basis. The RSUs accrue quarterly dividends in the form of additional RSUs. Upon vesting, the RSUs will become exercisable and will be distributed in **DPL** common stock, unless the Director chooses to defer receipt of the shares until a later date. The RSUs are valued at the closing stock price on the day prior to the grant and the compensation expense is recognized evenly over the vesting period.

$ in millions	Number of Director RSUs	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2010	20,712	$ 0.4
Granted in 2010	15,752	0.4
Dividends accrued in 2010	2,484	0.1
Vested, exercised and issued in 2010	(2,618)	(0.1)
Vested, exercised and deferred in 2010	(20,010)	(0.4)
Forfeited in 2010	—	—
Non-vested at December 31, 2010	16,320	$ 0.4

	For the years ended December 31, 2010	2009	2008
Restricted stock units:			
Outstanding at beginning of year	**20,712**	15,546	13,573
Granted	**15,752**	20,016	17,022
Dividends accrued	**2,484**	1,737	931
Vested, exercised and issued	**(2,618)**	(2,066)	(7,910)
Vested, exercised and deferred	**(20,010)**	(14,521)	(6,921)
Forfeited	**—**	—	(1,149)
Outstanding at period end	**16,320**	20,712	15,546
Exercisable at period end	**—**	—	—

The following table reflects information about non-employee director RSU activity during the period:

$ in millions	For the years ended December 31, 2010	2009	2008
Weighted-average grant date fair value of non-employee director RSUs granted during the period	$ **0.5**	$ 0.5	$ 0.5
Intrinsic value of non-employee director RSUs exercised during the period	$ **0.5**	$ 0.4	$ 0.4
Proceeds from non-employee director RSUs exercised during the period	$ **—**	$ —	$ —
Excess tax benefit from proceeds of non-employee director RSUs exercised	$ **—**	$ —	$ —
Fair value of non-employee director RSUs that vested during the period	$ **0.6**	$ 0.5	$ 0.5
Unrecognized compensation expense	$ **0.1**	$ 0.1	$ 0.1
Weighted average period to recognize compensation expense (in years)	**0.3**	0.3	0.3

Management Performance Shares

Under the EPIP, the Board of Directors granted compensation awards for select management employees. The grants have a three year requisite service period and certain performance conditions during the performance period. The management performance shares can only be awarded in **DPL** common stock.

$ in millions	Number of Mgt. Performance Shares	Weighted-Avg. Grant Date Fair Value
Non-vested at January 1, 2010	84,241	$ 2.1
Granted in 2010	37,480	0.9
Vested in 2010	(31,081)	(0.9)
Forfeited in 2010	(17,597)	(0.4)
Non-vested at December 31, 2010	73,043	$ 1.7

	For the years ended December 31, 2010	2009	2008
Management Performance Shares:			
Outstanding at beginning of year	**84,241**	39,144	—
Granted	**37,480**	48,719	39,144
Exercised	**—**	—	—
Forfeited	**(17,597)**	(3,622)	—
Outstanding at period end	**104,124**	84,241	39,144
Exercisable at period end	**31,081**	—	—

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the management performance shares granted during the period:

	For the years ended December 31, 2010	2009	2008
Expected volatility	**24.3%**	22.8%	14.9%
Weighted-average expected volatility	**24.3%**	22.8%	14.9%
Expected life (years)	**3.0**	3.0	3.0
Expected dividends	**4.5%**	5.6%	3.9%
Weighted-average expected dividends	**4.5%**	5.6%	3.9%
Risk-free interest rate	**1.4%**	1.5%	2.9%

The following table reflects information about management performance share activity during the period:

$ in millions	For the years ended December 31, 2010	2009	2008
Weighted-average grant date fair value of management perfomance shares granted during the period	$ 0.9	$ 1.0	$ 1.1
Intrinsic value of management performance shares exercised during the period	$ —	$ —	$ —
Proceeds from management performance shares exercised during the period	$ —	$ —	$ —
Excess tax benefit from proceeds of management performance shares exercised	$ —	$ —	$ —
Fair value of management performance shares that vested during the period	$ 0.9	$ —	$ —
Unrecognized compensation expense	$ 0.9	$ 1.0	$ 0.8
Weighted average period to recognize compensation expense (in years)	1.7	1.6	2.0

11. Redeemable Preferred Stock

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding as of December 31, 2010. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2010. The table below details the preferred shares outstanding at December 31, 2010:

	Preferred Stock Rate	Redemption Price at December 31, 2010	Shares Outstanding at December 31, 2010	Par Value at December 31, 2010 ($ in millions)	Par Value at December 31, 2009 ($ in millions)
DP&L Series A	3.75%	$ 102.50	93,280	$ 9.3	$ 9.3
DP&L Series B	3.75%	$ 103.00	69,398	7.0	7.0
DP&L Series C	3.90%	$ 101.00	65,830	6.6	6.6
Total			228,508	$ 22.9	$ 22.9

The **DP&L** preferred stock may be redeemed at **DP&L's** option as determined by its Board of Directors at the per-share redemption prices indicated above, plus cumulative accrued dividends. In addition, **DP&L's** Amended Articles of Incorporation contain provisions that permit preferred stockholders to elect members of the Board of Directors in the event that cumulative dividends on the preferred stock are in arrears in an aggregate amount equivalent to at least four full quarterly dividends. Since this potential redemption-triggering event is not solely within the control of **DP&L**, the preferred stock is presented on the Balance Sheets as "Redeemable Preferred Stock" in a manner consistent with temporary equity.

As long as any **DP&L** preferred stock is outstanding, **DP&L's** Amended Articles of Incorporation also contain provisions restricting the payment of cash dividends on any of its common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds the net income of **DP&L** available for dividends on its common stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not impacted **DP&L's** ability to pay cash dividends and, as of December 31, 2010, **DP&L's** retained earnings of $616.9 million were all available for common stock dividends payable to **DPL**. We do not expect this restriction to have an effect on the payment of cash dividends in the future. **DPL** records dividends on preferred stock of **DP&L** within Interest expense on the Statements of Results of Operations.

12. Common Shareholders' Equity

DPL has 250,000,000 authorized common shares, of which 116,924,844 are outstanding at December 31, 2010. On October 27, 2010, the **DPL** Board of Directors approved a new Stock Repurchase Program under which **DPL** may repurchase up to $200 million of its common stock from time to time in the open market, through private transactions or otherwise. This 2010 Stock Repurchase Program is scheduled to run through December 31, 2013 but may be modified or terminated at any time without notice. Under this 2010 Stock Repurchase Program, **DPL** repurchased 2.04 million shares at an average per share price of $25.75 during the fourth quarter of 2010. At December 31, 2010, the amount still available that could be used to repurchase stock under this program is approximately $147.5 million.

Warrants

On October 28, 2009, the **DPL** Board of Directors approved a Stock Repurchase Program under which **DPL** may use proceeds from the exercise of **DPL** warrants by warrant holders to repurchase other outstanding **DPL** warrants or its common stock from time to time in the open market, through private transactions or otherwise. This 2009 Stock Repurchase Program is schedule to run through June 30, 2012, which is three months after the end of the warrant exercise period. Under this 2009 Stock Repurchase Program, **DPL** repurchased a total of 145,915 shares during the three months ended March 31, 2010 at an average per share price of $26.71, effectively utilizing the entire $3.9 million that was available to repurchase stock at December 31, 2009. However, additional funds could be available to repurchase stock if the 1.7 million warrants outstanding at December 31, 2010 are exercised for cash in the future.

In February 2000, **DPL** entered into a series of recapitalization transactions which included the issuance of 31.6 million warrants for an aggregate purchase price of $50 million. The warrants are exercisable, in whole or in part, for common shares at any time during the twelve-year period commencing on March 13, 2000. Each warrant is exercisable for one common share, subject to anti-dilution adjustments (e.g., stock split, stock dividend) at an exercise price of $21.00 per common share.

In addition, in the event of a declaration, issuance or consummation of any dividend, spin-off or other distribution or similar transaction by **DPL** of the capital stock of any of its subsidiaries, additional warrants of such subsidiary will be issued to the warrant holder so that after the transaction, the warrant holder will have the same interest in the fully diluted number of common shares of such subsidiary the warrant holder had in **DPL** immediately prior to such transaction.

Pursuant to the warrant agreement, **DPL** has authorized common shares sufficient to provide for the exercise in full of all outstanding warrants. At December 31, 2010, **DPL** had 1.7 million outstanding warrants which are exercisable in the future.

Dividend Reinvestment Plan

On March 1, 2009, **DPL** introduced a new direct stock purchase and dividend reinvestment plan. The plan provides both registered shareholders and new investors with the ability to purchase shares and also to reinvest their dividends. This plan is administered by Computershare Trust Company, N.A., and not by **DPL**.

Shareholder Rights Plan

In September 2001, **DPL**'s Board of Directors renewed its Shareholder Rights Plan, attaching one right to each common share outstanding at the close of business on December 13, 2001. The rights separate from the common shares and become exercisable at the exercise price of $130 per right in the event of certain attempted business combinations. In October 2010, **DPL's** Board of Directors voted to amend the Shareholder Rights Plan to accelerate the expiration date. **DPL** expects the Shareholder Rights Plan to expire during the first quarter of 2011.

ESOP

During October 1992, our Board of Directors approved the formation of a Company-sponsored ESOP to fund matching contributions to **DP&L's** 401(k) retirement savings plan and certain other payments to eligible full-time employees. This leveraged ESOP is funded by an exempt loan, which is secured by the ESOP shares. As debt service payments are made on the loan, shares are released on a pro rata basis. ESOP shares used to fund matching contributions to **DP&L's** 401(k) vest after three years of service; contributions after 2010 will vest after two years of service. Other compensation shares awarded vest immediately.

In general, participants are eligible for lump sum payments upon termination of their employment and the submission and subsequent approval of an application for benefits. Earlier distributions can occur for a Qualified Domestic Relations Order or for death. Otherwise, distribution must occur within 60 days after the plan year in which the later of one of the following events occur: 65th birthday, 10th anniversary of participation, or termination of employment. Participants are allowed to take distributions during employment if older than 59½ and/or for a hardship as defined in the Plan document. Additionally, participants may elect on a quarterly basis to diversify their vested ESOP shares into **DP&L's** 401(k) retirement savings plan. Distributions are made in cash unless the participant requests the distribution be made in stock. A repurchase obligation exists for vested shares held by the ESOP if they cannot be sold in the open market. The fair value of shares subject to the repurchase obligation at December 31, 2010 and 2009 was approximately $54.1 million and $57.6 million, respectively.

In 1992, the Plan entered into a $90 million loan agreement with **DPL** in order to purchase shares of **DPL** common stock in the open market. The term loan agreement provided for principal and interest on the loan to be paid prior to October 9, 2007, with the right to extend the loan for an additional ten years. In 2007, the maturity date was extended to October 7, 2017. Effective January 1, 2009, the interest on the loan was amended to a fixed rate of 2.06%, payable annually. Dividends received by the ESOP are used to repay the principal and interest on the ESOP loan to **DPL**. Dividends on the allocated shares are charged to retained earnings and the share value of these dividends is allocated to participants.

The ESOP used the full amount of the loan to purchase 4.7 million shares of **DPL** common stock in the open market. As a result of the 1997 stock split, the ESOP held 7.1 million shares of **DPL** common stock. The cost of shares held by the ESOP and not yet released is reported as a reduction of Common shareholders' equity. At December 31, 2010, Common shareholders' equity reflects the cost of 2.5 million unreleased shares held in suspense by the DPL Inc. Employee Stock Ownership Trust. The fair value of the 2.5 million ESOP shares held in suspense at December 31, 2010 was $65.3 million. When shares are committed to be released from the ESOP, compensation expense is recorded based on the fair value of the shares committed to be released, with a corresponding credit to our equity. Compensation expense associated with the ESOP, which is based on the fair value of the shares committed to be released for allocation, amounted to $6.7 million in 2010, $4.0 million in 2009 and $1.5 million in 2008.

For purposes of EPS computations and in accordance with GAAP, we treat ESOP shares as outstanding if they have been allocated to participants, released or have been committed to be released. As of December 31, 2010, the ESOP has 4.5 million shares allocated to participants with an additional 0.1 million shares which have been released or committed to be released but unallocated to participants. ESOP cumulative shares outstanding for the calculation of EPS were 4.6 million in 2010, 4.2 million in 2009 and 4.0 million in 2008.

13. Comprehensive Income (Loss)

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

The following table provides the tax effects allocated to each component of Other comprehensive income (loss) for the years ended December 31, 2010, 2009 and 2008:

	DPL			DP&L		
$ in millions	Amount before tax	Tax (expense) / benefit	Amount after tax	Amount before tax	Tax (expense) / benefit	Amount after tax
2008:						
Unrealized gains / (losses) on financial instruments	$ (0.8)	$ 0.3	$ (0.5)	$ (15.0)	$ 5.2	$ (9.8)
Deferred gains / (losses) on cash flow hedges	(1.3)	(0.4)	(1.7)	(1.3)	(0.4)	(1.7)
Unrealized gains / (losses) on pension and postretirement benefits	(33.1)	11.6	(21.5)	(33.4)	11.7	(21.7)
Other comprehensive income (loss)	$ (35.2)	$ 11.5	$ (23.7)	$ (49.7)	$ 16.5	$ (33.2)
2009:						
Unrealized gains / (losses) on financial instruments	$ 0.8	$ (0.3)	$ 0.5	$ 4.2	$ (1.5)	$ 2.7
Deferred gains / (losses) on cash flow hedges	(4.3)	0.6	(3.7)	(4.3)	0.6	(3.7)
Unrealized gains / (losses) on pension and postretirement benefits	(4.1)	1.4	(2.7)	(4.1)	1.4	(2.7)
Other comprehensive income (loss)	$ (7.6)	$ 1.7	$ (5.9)	$ (4.2)	$ 0.5	$ (3.7)
2010:						
Unrealized gains / (losses) on financial instruments	**$ 0.6**	**$ (0.2)**	**$ 0.4**	**$ (1.6)**	**$ 0.6**	**$ (1.0)**
Deferred gains / (losses) on cash flow hedges	**11.0**	**(4.6)**	**6.4**	**(3.1)**	**0.3**	**(2.8)**
Unrealized gains / (losses) on pension and postretirement benefits	**4.3**	**(1.0)**	**3.3**	**4.3**	**(1.0)**	**3.3**
Other comprehensive income (loss)	**$ 15.9**	**$ (5.8)**	**$ 10.1**	**$ (0.4)**	**$ (0.1)**	**$ (0.5)**

The following table provides the detail of each component of Other comprehensive income (loss) reclassified to Net income during the years ended December 31, 2010, 2009 and 2008:

DPL

$ in millions	2010	2009	2008
No unrealized gains or losses on financial instruments were transferred to income in 2010, 2009 or 2008.	$ —	$ —	$ —
Deferred gains/(losses) on cash flow hedges net of income tax (expenses)/benefits of $2.0 million, ($1.8) million and ($2.2) million, respectively.	(6.0)	5.9	6.5
Unrealized losses on pension and postretirement benefits net of income tax benefits of $1.3 million, $1.1 million and $0.7 million, respectively.	(2.4)	(2.1)	(1.3)
	$ (8.4)	$ 3.8	$ 5.2

DP&L

$ in millions	2010	2009	2008
Unrealized gains/(losses) on financial instruments net of income tax (expenses)/benefits of zero, ($0.4) million and ($1.4) million, respectively.	$ (0.1)	$ 0.7	$ 2.7
Deferred gains/(losses) on cash flow hedges net of income tax (expenses)/benefits of $2.0 million, ($1.8) million and ($2.2) million, respectively.	(6.0)	5.9	6.5
Unrealized losses on pension and postretirement benefits net of income tax benefits of $1.3 million, $1.1 million and $0.7 million, respectively.	(2.4)	(2.1)	(1.3)
	$ (8.5)	$ 4.5	$ 7.9

Accumulated Other Comprehensive Income (Loss)

AOCI is included on our balance sheets within the Common shareholders' equity sections. The following table provides the components that constitute the balance sheet amounts in AOCI at December 31, 2010 and 2009:

DPL

$ in millions	2010	2009
Financial instruments, net of tax	$ 0.6	$ 0.2
Cash flow hedges, net of tax	19.6	13.3
Pension and postretirement benefits, net of tax	(39.1)	(42.5)
Total	$ (18.9)	$ (29.0)

DP&L

$ in millions	2010	2009
Financial instruments, net of tax	$ 8.4	$ 9.5
Cash flow hedges, net of tax	10.5	13.3
Pension and postretirement benefits, net of tax	(39.1)	(42.5)
Total	$ (20.2)	$ (19.7)

14. EPS

Basic EPS is based on the weighted-average number of **DPL** common shares outstanding during the year. Diluted EPS is based on the weighted-average number of **DPL** common and common-equivalent shares outstanding during the year, except in periods where the inclusion of such common-equivalent shares is anti-dilutive. Excluded from outstanding shares for these weighted-average computations are shares held by **DP&L's** Master Trust Plan for deferred compensation and unreleased shares held by **DPL's** ESOP.

The common-equivalent shares excluded from the calculation of diluted EPS, because they were anti-dilutive, were not material for all the periods ended December 31, 2010, 2009 and 2008. These shares may be dilutive in the future.

The following illustrates the reconciliation of the numerators and denominators of the basic and diluted EPS computations:

	2010			2009			2008		
$ and shares in millions except per share amounts	**Income**	**Shares**	**Per Share**	**Income**	**Shares**	**Per Share**	**Income**	**Shares**	**Per Share**
Basic EPS	**$ 290.3**	**115.6**	**$ 2.51**	$ 229.1	112.9	$ 2.03	$ 244.5	110.2	$ 2.22
Effect of Dilutive Securities:									
Warrants		**0.3**			1.1			5.0	
Stock options, performance and restricted shares		**0.2**			0.2			0.2	
Diluted EPS	**$ 290.3**	**116.1**	**$ 2.50**	$ 229.1	114.2	$ 2.01	$ 244.5	115.4	$ 2.12

15. Insurance Recovery

On May 16, 2007, **DPL** filed a claim with Energy Insurance Mutual (EIM) to recoup legal costs associated with our litigation against certain former executives. On February 15, 2010, after having engaged in both mediation and arbitration, **DPL** and EIM entered into a settlement agreement resolving all coverage issues and finalizing all obligations in connection with the claim. The proceeds from the settlement amounted to $3.4 million, net of associated expenses, and were recorded as a reduction to operation and maintenance expense during the year ended December 31, 2010.

16. Contractual Obligations, Commercial Commitments and Contingencies

DPL — Guarantees

In the normal course of business, **DPL** enters into various agreements with its wholly-owned subsidiaries, DPLE and DPLER, providing financial or performance assurance to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to DPLE and DPLER on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish DPLE's and DPLER's intended commercial purposes.

At December 31, 2010, **DPL** had $57.8 million of guarantees to third parties for future financial or performance assurance under such agreements, on behalf of DPLE and DPLER. The guarantee arrangements entered into by **DPL** with these third parties cover all present and future obligations of DPLE and DPLER to such beneficiaries and are terminable at any time by **DPL** upon written notice to the beneficiaries. The carrying amount of obligations for commercial transactions covered by these guarantees and recorded in our Consolidated Balance Sheets was $1.7 million and $0.6 million at December 31, 2010 and 2009, respectively.

To date, neither **DPL** nor **DP&L** have incurred any losses related to the guarantees of DPLE's and DPLER's obligations and we believe it is remote that either **DPL** or **DP&L** would be required to perform or incur any losses in the future associated with any of the above guarantees of DPLE's and DPLER's obligations.

DP&L — Equity Ownership Interest

DP&L owns a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. As of December 31, 2010, **DP&L** could be responsible for the repayment of 4.9%, or $62.3 million, of a $1,272.2 million debt obligation that matures in 2026. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2010, we have no knowledge of such a default.

Contractual Obligations and Commercial Commitments

We enter into various contractual obligations and other commercial commitments that may affect the liquidity of our operations. At December 31, 2010, these include:

		Payment Year			
$ in millions	Total	2011	2012-2013	2014-2015	Thereafter
DPL					
Long-term debt	$ 1,324.4	$ 297.4	$ 470.0	$ —	$ 557.0
Interest payments	677.9	64.7	96.1	53.9	463.2
Pension and postretirement payments	258.5	23.8	51.0	52.0	131.7
Capital leases	0.2	0.1	0.1	—	—
Operating leases	0.9	0.4	0.3	0.2	—
Coal contracts (a)	1,409.0	415.2	501.3	177.6	314.9
Limestone contracts (a)	42.9	5.6	11.7	12.4	13.2
Purchase orders and other contractual obligations	141.5	71.1	56.0	11.7	2.7
Total contractual obligations	$ 3,855.3	$ 878.3	$ 1,186.5	$ 307.8	$ 1,482.7
DP&L					
Long-term debt	$ 884.4	$ —	$ 470.0	$ —	$ 414.4
Interest payments	424.8	39.5	72.9	30.7	281.7
Pension and postretirement payments	258.5	23.8	51.0	52.0	131.7
Capital leases	0.2	0.1	0.1	—	—
Operating leases	0.9	0.4	0.3	0.2	—
Coal contracts (a)	1,409.0	415.2	501.3	177.6	314.9
Limestone contracts (a)	42.9	5.6	11.7	12.4	13.2
Purchase orders and other contractual obligations	142.7	72.2	56.1	11.7	2.7
Total contractual obligations	$ 3,163.4	$ 556.8	$ 1,163.4	$ 284.6	$ 1,158.6

(a) Total at **DP&L**-operated units

Long-term debt:

DPL's long-term debt as of December 31, 2010, consists of **DP&L's** first mortgage bonds and tax-exempt pollution control bonds and **DPL's** unsecured senior notes. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

DP&L's long-term debt as of December 31, 2010, consists of first mortgage bonds and tax-exempt pollution control bonds. These long-term debt amounts include current maturities but exclude unamortized debt discounts. See Note 5 and Note 18 of Notes to Consolidated Financial Statements.

Interest payments:

Interest payments are associated with the long-term debt described above. The interest payments relating to variable-rate debt are projected using the interest rate prevailing at December 31, 2010.

Pension and postretirement payments:

As of December 31, 2010, **DPL**, through its principal subsidiary **DP&L**, had estimated future benefit payments as outlined in Note 7 of Notes to Consolidated Financial Statements. These estimated future benefit payments are projected through 2020.

Capital leases:

As of December 31, 2010, **DPL**, through its principal subsidiary **DP&L**, had one immaterial capital lease that expires in 2013.

Operating leases:

As of December 31, 2010, **DPL**, through its principal subsidiary **DP&L**, had several immaterial operating leases with various terms and expiration dates.

Coal contracts:

DPL, through its principal subsidiary **DP&L**, has entered into various long-term coal contracts to supply the coal requirements for the generating plants it operates. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Limestone contracts:

DPL, through its principal subsidiary **DP&L**, has entered into various limestone contracts to supply limestone used in the operation of FGD equipment at its generating facilities.

Purchase orders and other contractual obligations:

As of December 31, 2010, **DPL** and **DP&L** had various other contractual obligations including non-cancelable contracts to purchase goods and services with various terms and expiration dates.

Reserve for uncertain tax positions:

Due to the uncertainty regarding the timing of future cash outflows associated with our unrecognized tax benefits of $19.4 million, we are unable to make a reliable estimate of the periods of cash settlement with the respective tax authorities and have not included such amounts in the contractual obligations table above.

Contingencies

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our Consolidated Financial Statements, as prescribed by GAAP, are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims, tax examinations, and other matters, including the matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our Consolidated Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2010, cannot be reasonably determined.

Environmental Matters

DPL, **DP&L** and our subsidiaries' facilities and operations are subject to a wide range of environmental regulations and laws by federal, state and local authorities. As well as imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at these facilities to comply, or to determine compliance, with such regulations. We record liabilities for losses that are probable of occurring and can be reasonably estimated. We have reserves of approximately $4.0 million for environmental matters. We evaluate the potential liability related to probable losses quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material effect on our results of operations, financial condition or cash flows.

We have several pending environmental matters associated with our power plants. Some of these matters could have material adverse impacts on the operation of the power plants; especially the plants that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired power plants that do not have this equipment installed. **DP&L** owns 100% of the Hutchings plant and a 50% interest in Beckjord Unit 6.

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Regulation Matters Related to Air Quality

Clean Air Act Compliance

In 1990, the federal government amended the CAA to further regulate air pollution. Under the law, the USEPA sets limits on how much of a pollutant can be in the air anywhere in the United States. The CAA allows individual states to have stronger pollution controls, but states are not allowed to have weaker pollution controls than those set for the whole country. The CAA has a material effect on our operations and such effects are detailed below with respect to certain programs under the CAA.

On October 27, 2003, the USEPA published final rules regarding the equipment replacement provision (ERP) of the routine maintenance, repair and replacement (RMRR) exclusion of the CAA. Activities at power plants that fall within the scope of the RMRR exclusion do not trigger new source review (NSR) requirements, including the imposition of stricter emission limits. On December 24, 2003, the United States Court of Appeals for the D.C. Circuit stayed the effective date of the rule pending its decision on the merits of the lawsuits filed by numerous states and environmental organizations challenging the final rules. On June 6, 2005, the USEPA issued its final response on the reconsideration of the ERP exclusion. The USEPA clarified its position, but did not change any aspect of the 2003 final rules. This decision was appealed and the D.C. Circuit vacated the final rules on March 17, 2006. The scope of the RMRR exclusion remains uncertain due to this action by the D.C. Circuit, as well as multiple litigations not directly involving us where courts are defining the scope of the exception with respect to the specific facts and circumstances of the particular power plants and activities before the courts. While we believe that we have not engaged in any activities with respect to our existing power plants that would trigger the NSR requirements, if NSR requirements were imposed on any of **DP&L's** existing power plants, the results could have a material adverse impact to us.

The USEPA issued a proposed rule on October 20, 2005 concerning the test for measuring whether modifications to electric generating units should trigger application of NSR standards under the CAA. A supplemental rule was also proposed on May 8, 2007 to include additional options for determining if there is an emissions increase when an existing electric generating unit makes a physical or operational change. The rule was challenged by environmental organizations and has not been finalized. While we cannot predict the outcome of this rulemaking, any finalized rules could materially affect our operations.

Interstate Air Quality Rule

On December 17, 2003, the USEPA proposed the Interstate Air Quality Rule (IAQR) designed to reduce and permanently cap SO_2 and NOx emissions from electric utilities. The proposed IAQR focused on states, including Ohio, whose power plant emissions are believed to be significantly contributing to fine particle and ozone pollution in other downwind states in the eastern United States. On June 10, 2004, the USEPA issued a supplemental proposal to the IAQR, now renamed the Clean Air Interstate Rule (CAIR). The final rules were signed on March 10, 2005 and were published on May 12, 2005. CAIR created an interstate trading program for annual NOx emission allowances and made modifications to an existing trading program for SO_2. On August 24, 2005, the USEPA proposed additional revisions to the CAIR. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision to vacate the USEPA's CAIR and its associated Federal Implementation Plan and remanded to the USEPA with instructions to issue new regulations that conformed with the procedural and substantive requirements of the CAA. The Court's decision, in part, invalidated the new NOx annual emission allowance trading program and the modifications to the SO_2 emission trading program established by the March 10, 2005 rules, and created uncertainty regarding future NOx and SO_2 emission reduction requirements and their timing. The USEPA and a group representing utilities filed a request on September 24, 2008 for a rehearing before the entire Court. On December 23, 2008, the U.S. Court of Appeals issued an order on reconsideration that permits CAIR to remain in effect until the USEPA issues new regulations that would conform to the CAA requirements and the Court's July 11, 2008 decision.

In the fourth quarter of 2007, **DP&L** began a program for selling excess emission allowances, including annual NOx emission allowances and SO_2 emission allowances that were the subject of CAIR trading programs. In subsequent quarters, **DP&L** recognized gains from the sale of excess emission allowances to third parties. The Court's CAIR decision affected the trading market for excess allowances and impacted **DP&L's** program for selling additional excess allowances in 2008. In January 2009, we resumed selling excess allowances due to the revival of the emissions trading market. On July 6, 2010, the USEPA proposed the Clean Air Transport Rule (CATR) which will effectively replace CAIR. We have reviewed this proposal and submitted comments to the USEPA on September 30, 2010. We are unable to determine the overall financial impact that these rules could have on our operations in the future.

In 2007, the Ohio EPA revised their State Implementation Plan (SIP) to incorporate a CAIR program consistent with the IAQR. The Ohio EPA had received partial approval from the USEPA and had been awaiting full program approval from the USEPA when the U.S. Court of Appeals issued its July 11, 2008 decision. As a result of the December 23, 2008 order, the Ohio EPA proposed revised rules on May 11, 2009, which were finalized on July 15, 2009. On September 25, 2009, the USEPA issued a full SIP approval for the Ohio CAIR program. We do not expect that full SIP approval of the Ohio CAIR program will have a significant impact on operations.

Mercury and Other Hazardous Air Pollutants

On January 30, 2004, the USEPA published its proposal to restrict mercury and other air toxins from coal-fired and oil-fired utility plants. The USEPA "de-listed" mercury as a hazardous air pollutant from coal-fired and oil-fired utility plants and, instead, proposed a cap-and-trade approach to regulate the total amount of mercury emissions allowed from such sources. The final Clean Air Mercury Rule (CAMR) was signed March 15, 2005 and was published on May 18, 2005. On March 29, 2005, nine states sued the USEPA, opposing the cap-and-trade regulatory approach taken by the USEPA. In 2007, the Ohio EPA adopted rules implementing the CAMR program. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit struck down the USEPA regulations, finding that the USEPA had not complied with statutory requirements applicable to "de-listing" a hazardous air pollutant and that a cap-and-trade approach was not authorized by law for "listed" hazardous air pollutants. A request for rehearing before the entire Court of Appeals was denied and a petition for review before the U.S. Supreme Court was filed on October 17, 2008. On February 23, 2009, the U.S. Supreme Court denied the petition. The USEPA is expected to propose Maximum Achievable Control Technology (MACT) standards for coal- and oil-fired electric generating units during the quarter ending March 31, 2011 and finalize during the quarter ending December 31, 2011. Upon publication in the federal register following finalization, affected electric generating units (EGUs) will have three years to come into compliance with the new requirements. **DP&L** is unable to determine the impact of the promulgation of new MACT standards on its financial condition or results of operations; however, a MACT standard could have a material adverse effect on our operations. We cannot predict the final costs we may incur to comply with proposed new regulations to control mercury or other hazardous air pollutants.

On April 29, 2010, the USEPA issued a proposed rule that would reduce emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers, and process heaters at major and area source facilities. This regulation may affect five auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The proposed regulations contain emissions limitations, operating limitations and other requirements. The compliance schedule will be three years from the date when these rules, if finalized, become effective. We currently cannot determine whether or not these rules will be finalized nor can we predict the effect of compliance costs, if any, on **DP&L's** operations. Such costs, however, are not expected to be material.

On May 3, 2010, the USEPA finalized the "National Emissions Standards for Hazardous Air Pollutants" (NESHAP) for compression ignition (CI) reciprocating internal combustion engines (RICE). The units affected at **DP&L** are 18 diesel electric generating engines and eight emergency "black start" engines. The existing CI RICE units must comply by May 3, 2013. The regulations contain emissions limitations, operating limitations and other requirements. Compliance costs on **DP&L's** operations are not expected to be material.

National Ambient Air Quality Standards

On January 5, 2005, the USEPA published its final non-attainment designations for the National Ambient Air Quality Standard (NAAQS) for Fine Particulate Matter 2.5 (PM 2.5). These designations included counties and partial counties in which **DP&L** operates and/or owns generating facilities. On March 4, 2005, **DP&L** and other Ohio electric utilities and electric generators filed a petition for review in the D.C. Circuit Court of Appeals, challenging the final rule creating these designations. On November 30, 2005, the court ordered the USEPA to decide on all petitions for reconsideration by January 20, 2006. On January 20, 2006, the USEPA denied the petitions for reconsideration. On July 7, 2009, the D.C. Circuit Court of Appeals upheld the USEPA non-attainment designations for the areas impacting **DP&L's** generation plants, however, on October 8, 2009 the USEPA issued new designations based on 2008 monitoring data that showed all areas in attainment to the standard with the exception of several counties in northeastern Ohio. The USEPA is expected to propose revisions to the PM 2.5 standard during the first quarter of 2011 as part of its routine five-year rule review cycle. We cannot predict the impact the revisions to the PM 2.5 standard will have on **DP&L's** financial condition or results of operations.

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On May 5, 2004, the USEPA issued its proposed regional haze rule, which addresses how states should determine the Best Available Retrofit Technology (BART) for sources covered under the regional haze rule. Final rules were published July 6, 2005, providing states with several options for determining whether sources in the state should be subject to BART. In the final rule, the USEPA made the determination that CAIR achieves greater progress than BART and may be used by states as a BART substitute. Numerous units owned and operated by us will be impacted by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. A more stringent ambient ozone standard may lead to stricter NOx emission standards in the future. **DP&L** cannot determine the effect of this potential change, if any, on its operations.

Effective April 12, 2010, the USEPA implemented revisions to its primary NAAQS for nitrogen dioxide. This change may affect certain emission sources in heavy traffic areas like the I-75 corridor between Cincinnati and Dayton after 2016. Several of our facilities or co-owned facilities are within this area. **DP&L** cannot determine the effect of this potential change, if any, on its operations.

Effective August 23, 2010, the USEPA implemented revisions to its primary NAAQS for SO_2 replacing the current 24-hour standard and annual standard with a one hour standard. **DP&L** cannot determine the effect of this potential change, if any, on its operations. No effects are anticipated before 2014.

Climate Change

In response to a U.S. Supreme Court decision that the USEPA has the authority to regulate CO_2 emissions from motor vehicles, the USEPA made a finding that CO_2 and certain other GHGs are pollutants under the CAA. Subsequently, under the CAA, USEPA determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This finding became effective in January 2010. Numerous affected parties have petitioned the USEPA Administrator to reconsider this decision. On April 1, 2010, USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under USEPA's view, this is the final action that renders carbon dioxide and other GHGs "regulated air pollutants" under the CAA. As a result of this action, it is expected that in 2011 various permitting programs will apply to other combustion sources, such as coal-fired power plants. We cannot predict the effect of this change, if any, on **DP&L's** operations.

Legislation proposed in 2009 to target a reduction in the emission of GHGs from large sources was not enacted. Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 16 million tons annually. Proposed GHG legislation finalized at a future date could have a significant effect on **DP&L's** operations and costs, which could adversely affect our net income, cash flows and financial condition. However, due to the uncertainty associated with such legislation, we cannot predict the final outcome or the financial impact that this legislation will have on **DP&L**.

On September 22, 2009, the USEPA issued a final rule for mandatory reporting of GHGs from large sources that emit 25,000 metric tons per year or more of CO_2, including electric generating units. The first report is due in March 2011 for 2010 emissions. This reporting rule will guide development of policies and programs to reduce emissions. **DP&L** does not anticipate that this reporting rule will result in any significant cost or other impact on current operations.

Litigation, Notices of Violation and Other Matters Related to Air Quality

Litigation Involving Co-Owned Plants

In 2004, eight states and the City of New York filed a lawsuit in Federal District Court for the Southern District of New York against American Electric Power Company, Inc. (AEP), one of AEP's subsidiaries, Cinergy Corp. (a subsidiary of Duke Energy Corporation (Duke Energy)) and four other electric power companies. A similar lawsuit was filed against these companies in the same court by Open Space Institute, Inc., Open Space Conservancy, Inc. and The Audubon Society of New Hampshire. The lawsuits allege that the companies' emissions of CO_2 contribute to global warming and constitute a public or private nuisance. The lawsuits seek injunctive relief in the form of specific emission reduction commitments. In 2005, the Federal District Court dismissed the lawsuits, holding that the lawsuits raised political questions that should not be decided by the courts. The plaintiffs appealed. Finding that the plaintiffs have standing to sue and can assert federal common law nuisance claims, the United States Court of Appeals for the Second Circuit on September 21, 2009 vacated the dismissal of the Federal District Court and remanded the lawsuits back to the Federal District Court for further proceedings. In response to a petition by the company defendants, the U.S. Supreme Court on December 6, 2010 granted a hearing on the matter. Although we are not named as a party to these lawsuits, **DP&L** is a co-owner of coal-fired plants with Duke Energy and AEP (or their subsidiaries) that could be affected by the outcome of these lawsuits. The outcome of these lawsuits could also encourage these or other plaintiffs to file similar lawsuits against other electric power companies, including **DP&L**. We are unable to predict the impact that these lawsuits might have on **DP&L**.

On September 21, 2004, the Sierra Club filed a lawsuit against **DP&L** and the other owners of the J.M. Stuart generating station in the U.S. District Court for the Southern District of Ohio for alleged violations of the CAA and the station's operating permit. On August 7, 2008, a consent decree was filed in the U.S. District Court in full settlement of these CAA claims. Under the terms of the consent decree, **DP&L** and the other owners of the J.M. Stuart generating station agreed to: (i) certain emission targets related to NOx, SO_2 and particulate matter; (ii) make energy efficiency and renewable energy commitments that are conditioned on receiving PUCO approval for the recovery of costs; (iii) forfeit 5,500 SO_2 allowances; and (iv) provide funding to a third party non-profit organization to establish a solar water heater rebate program. **DP&L** and the other owners of the station also entered into an attorneys' fee agreement to pay a portion of the Sierra Club's attorney and expert witness fees. The parties to the lawsuit filed a joint motion on October 22, 2008, seeking an order by the U.S. District Court approving the consent decree with funding for the third party non-profit organization set at $300,000. On October 23, 2008, the U.S. District Court approved the consent decree. On October 21, 2009, the Sierra Club filed with the U.S. District Court a motion for enforcement of the consent decree based on the Sierra Club's interpretation of the consent decree that would require certain NOx emissions that **DP&L** has been excluding from its computations to be included for purposes of complying with the emission targets and reporting requirements of the consent decree. **DP&L** believed that it was properly computing and reporting NOx emissions under the consent decree, but participated in settlement discussions with the Sierra Club. A proposed settlement was agreed to by both parties, approved by the Judge and then filed into the official record on July 13, 2010. The settlement amends the Consent Decree and sets forth a more detailed and clear methodology to compute NOx emissions during start-up and shut-down periods. There were no cash payments under the terms of this settlement. The revision is not expected to have a material effect on **DP&L's** results of operations, financial condition or cash flows in the future.

Notices of Violation Involving Co-Owned Plants

In November 1999, the USEPA filed civil complaints and NOVs against operators and owners of certain generation facilities for alleged violations of the CAA. Generation units operated by Duke Energy (Beckjord Unit 6) and CSP (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. Numerous northeast states have filed complaints or have indicated that they will be joining the USEPA's action against Duke Energy and CSP. Although **DP&L** was not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect **DP&L's** co-owned plants.

In June 2000, the USEPA issued a NOV to the **DP&L**-operated J.M. Stuart generating station (co-owned by **DP&L**, Duke Energy, and CSP) for alleged violations of the CAA. The NOV contained allegations consistent with NOVs and complaints that the USEPA had recently brought against numerous other coal-fired utilities in the Midwest. The NOV indicated the USEPA may: (1) issue an order requiring compliance with the requirements of the Ohio SIP; or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. To date, neither action has been taken. **DP&L** cannot predict the outcome of this matter.

In December 2007, the Ohio EPA issued a NOV to the **DP&L**-operated Killen generating station (co-owned by **DP&L** and Duke Energy) for alleged violations of the CAA. The NOVs alleged deficiencies in the continuous monitoring of opacity. We submitted a compliance plan to the Ohio EPA on December 19, 2007. To date, no further actions have been taken by the Ohio EPA.

On March 13, 2008, Duke Energy, the operator of the Zimmer generating station, received a NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio State Implementation Program (SIP) and permits for the Station in areas including SO_2, opacity and increased heat input. A second NOV and FOV with similar allegations was issued on November 4, 2010. **DP&L** is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of these matters. Duke Energy Ohio Inc. is expected to act on behalf of itself and the co-owners with respect to these matters. **DP&L** is unable to predict the outcome of these matters.

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Other Issues Involving Co-Owned Plants

In 2006, **DP&L** detected a malfunction with its emission monitoring system at the **DP&L**-operated Killen generating station (co-owned by **DP&L** and Duke Energy) and ultimately determined its SO_2 and NOx emissions data were under reported. **DP&L** has petitioned the USEPA to accept an alternative methodology for calculating actual emissions for 2005 and the first quarter of 2006. **DP&L** has sufficient allowances in its general account to cover the understatement. Management does not believe the ultimate resolution of this matter will have a material impact on results of operations, financial condition or cash flows.

Notices of Violation Involving Wholly-Owned Plants

In 2007, the Ohio EPA and the USEPA issued NOVs to **DP&L** for alleged violations of the CAA at the O.H. Hutchings Station. The NOVs' alleged deficiencies relate to stack opacity and particulate emissions. Discussions are under way with the USEPA, the U.S. Department of Justice and Ohio EPA. **DP&L** has provided data to those agencies regarding its maintenance expenses and operating results. On December 15, 2008, **DP&L** received a request from the USEPA for additional documentation with respect to those issues and other CAA issues including issues relating to capital expenses and any changes in capacity or output of the units at the O.H. Hutchings Station. During 2009, **DP&L** continued to submit various other operational and performance data to the USEPA in compliance with its request. **DP&L** is currently unable to determine the timing, costs or method by which the issues may be resolved and continues to work with the USEPA on this issue.

On November 18, 2009, the USEPA issued a NOV to **DP&L** for alleged NSR violations of the CAA at the O.H. Hutchings Station relating to capital projects performed in 2001 involving Unit 3 and Unit 6. **DP&L** does not believe that the two projects described in the NOV were modifications subject to NSR. **DP&L** is unable to determine the timing, costs or method by which these issues may be resolved and continues to work with the USEPA on this issue.

Regulation Matters Related to Water Quality

Clean Water Act — Regulation of Water Intake

On July 9, 2004, the USEPA issued final rules pursuant to the Clean Water Act governing existing facilities that have cooling water intake structures. The rules require an assessment of impingement and/or entrainment of organisms as a result of cooling water withdrawal. A number of parties appealed the rules to the Federal Court of Appeals for the Second Circuit in New York and the Court issued an opinion on January 25, 2007 remanding several aspects of the rule to the USEPA for reconsideration. Several parties petitioned the U.S. Supreme Court for review of the lower court decision. On April 14, 2008, the Supreme Court elected to review the lower court decision on the issue of whether the USEPA can compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Briefs were submitted to the Court in the summer of 2008 and oral arguments were held in December 2008. In April 2009, the U.S. Supreme Court ruled that the USEPA did have the authority to compare costs with benefits in determining best technology available. The USEPA is developing proposed regulations and anticipates proposing requirements by March 2011 with final rules in place by mid-2012.

Clean Water Act — Regulation of Water Discharge

On May 4, 2004, the Ohio EPA issued a final National Pollutant Discharge Elimination System permit (the Permit) for J.M. Stuart Station that continued our authority to discharge water from the station into the Ohio River. During the three-year term of the Permit, we conducted a thermal discharge study to evaluate the technical feasibility and economic reasonableness of water cooling methods other than cooling towers. In December 2006, we submitted an application for the renewal of the Permit that was due to expire on June 30, 2007. In July 2007, we received a draft permit proposing to continue our authority to discharge water from the station into the Ohio River. On February 5, 2008, we received a letter from the Ohio EPA indicating that they intended to impose a compliance schedule as part of the final Permit, that requires us to implement one of two diffuser options for the discharge of water from the station into the Ohio River as identified in the thermal discharge study. Subsequently, representatives from **DP&L** and the Ohio EPA agreed to allow **DP&L** to restrict public access to the water discharge area as an alternative to installing one of the diffuser options. Ohio EPA issued a revised draft permit that was received on November 12, 2008. In December 2008, the USEPA requested that the Ohio EPA provide additional information regarding the thermal discharge in the draft permit. In June 2009, **DP&L** provided information to the USEPA in response to their request to the Ohio EPA. In September 2010, the USEPA formally objected to a revised Permit provided by Ohio EPA due to questions regarding the basis for the alternate thermal limitation. In December 2010, **DP&L** requested a public hearing on the objection, which USEPA has agreed to conduct. If a public hearing is held, it is anticipated that it would be scheduled in the second half of 2011. We are attempting to resolve this issue with both the USEPA and Ohio EPA. The timing for issuance of a final permit is uncertain.

In September 2009, the USEPA announced that it will be revising technology-based regulations governing water discharges from steam electric generating facilities. The rulemaking included the collection of information via an industry-wide questionnaire as well as targeted water sampling efforts at selected facilities. Subsequent to the information collection effort, it is anticipated that the USEPA will release a proposed rule by mid-2012 with a final regulation in place by early 2014. At present, **DP&L** is unable to predict the impact this rulemaking will have on its operations.

Regulation Matters Related to Land Use and Solid Waste Disposal

Regulation of Waste Disposal

In September 2002, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the South Dayton Dump landfill site. In August 2005, **DP&L** and other parties received a general notice regarding the performance of a Remedial Investigation and Feasibility Study (RI/FS) under a Superfund Alternative Approach. In October 2005, **DP&L** received a special notice letter inviting it to enter into negotiations with the USEPA to conduct the RI/FS. No recent activity has occurred with respect to that notice or PRP status. However, on August 25, 2009, the USEPA issued an Administrative Order requiring that access to **DP&L**'s service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. **DP&L** has granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. **DP&L** believes the chemicals used at its service center building site were appropriately disposed of and have not contributed to the contamination at the South Dayton Dump landfill site. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against **DP&L** and numerous other defendants alleging that **DP&L** and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site. **DP&L** filed a motion to dismiss the complaint and intends to vigorously defend against any claim that it has any financial responsibility to remediate conditions at the landfill site. On February 10, 2011, the Court dismissed claims against **DP&L** that related to allegations that chemicals used by **DP&L** at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from **DP&L** that were allegedly directly delivered by truck to the landfill. While **DP&L** is unable to predict the outcome of these matters, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

In December 2003, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the Tremont City landfill site. Information available to **DP&L** does not demonstrate that it contributed hazardous substances to the site. While **DP&L** is unable to predict the outcome of this matter, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

On April 7, 2010, the USEPA published an Advance Notice of Proposed Rulemaking (ANPRM) announcing that it is reassessing existing regulations governing the use and distribution in commerce of polychlorinated biphenyls (PCB). While this reassessment is in the early stages and the USEPA is seeking information from potentially affected parties on how it should proceed, the outcome may have a material effect on **DP&L**. At present, **DP&L** is unable to predict the impact this initiative will have on its operations.

Regulation of Ash Ponds

During 2008, a major spill occurred at an ash pond owned by the Tennessee Valley Authority (TVA) as a result of a dike failure. The spill generated a significant amount of national news coverage, and support for tighter regulations for the storage and handling of coal combustion products. **DP&L** has ash ponds at the Killen, O.H. Hutchings and J.M. Stuart Stations which it operates, and also at generating stations operated by others but in which **DP&L** has an ownership interest.

During March 2009, the USEPA, through a formal Information Collection Request, collected information on ash pond facilities across the country, including those at Killen and J.M. Stuart Stations. Subsequently, the USEPA collected similar information for O.H. Hutchings Station. In October 2009, the USEPA conducted an inspection of the J.M. Stuart Station ash ponds. In March 2010, the USEPA issued a final report from the inspection including recommendations relative to the J.M. Stuart Station ash ponds. In May 2010, **DP&L** responded to the USEPA final inspection report with our plans to address the recommendations.

Similarly, in August 2010, the USEPA conducted an inspection of the O.H. Hutchings Station ash ponds. The draft report relating to the inspection was received in November 2010 and **DP&L** provided comments on the draft report in December 2010. **DP&L** is unable to predict the outcome this inspection will have on its operations.
In addition, as a result of the TVA ash pond spill, there has been increasing advocacy to regulate coal combustion byproducts under the Resource Conservation Recovery Act (RCRA). On June 21, 2010, the USEPA published a proposed rule seeking comments on two options under consideration for the regulation of coal combustion products including regulating the material as a hazardous waste under RCRA Subtitle C or as a solid waste under RCRA Subtitle D. **DP&L** is unable to predict the financial impact of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse impact on operations.

Legal and Other Matters

In February 2007, **DP&L** filed a lawsuit against a coal supplier seeking damages incurred due to the supplier's failure to supply approximately 1.5 million tons of coal to two jointly owned plants under a coal supply agreement, of which approximately 570 thousand tons was **DP&L's** share. **DP&L** obtained replacement coal to meet its needs. The supplier has denied liability, and is currently in federal bankruptcy proceedings in which **DP&L** is participating as an unsecured creditor. **DP&L** is unable to determine the ultimate resolution of this matter. **DP&L** has not recorded any assets relating to possible recovery of costs in this lawsuit.
On May 16, 2007, **DPL** filed a claim with Energy Insurance Mutual (EIM) to recoup legal costs associated with our litigation against certain former executives. On February 15, 2010, after having engaged in both mediation and arbitration, **DPL** and EIM entered into a settlement agreement resolving all coverage issues and finalizing all obligations in connection with the claim, under which **DPL** received $3.4 million (net of associated expenses).
As a member of PJM, **DP&L** is also subject to charges and costs associated with PJM operations as approved by the FERC. FERC Orders issued in 2007 and thereafter regarding the allocation of costs of large transmission facilities within PJM, could result in additional costs being allocated to **DP&L** of approximately $12 million or more annually by 2012. **DP&L** filed a notice of appeal to the U.S. Court of Appeals, D.C. Circuit which was consolidated with other appeals taken by other interested parties of the same FERC Orders and the consolidated cases were assigned to the 7th Circuit. On August 6, 2009, the 7th Circuit ruled that the FERC had failed to provide a reasoned basis for the allocation method it had approved. Rehearings were filed by other interested litigants and denied by the Court, which then remanded the matter to the FERC for further proceedings. On January 21, 2010, the FERC issued a procedural order on remand establishing a paper hearing process under which PJM will make an informational filing in late February. Subsequently PJM and other parties, including **DP&L**, filed initial comments, testimony, and recommendations and reply comments. FERC did not establish a deadline for its issuance of a substantive order and the matter is still pending. **DP&L** cannot predict the timing or the likely outcome of the proceeding. Until such time as FERC may act to approve a change in methodology, PJM will continue to apply the allocation methodology that had been approved by FERC in 2007. Although we continue to maintain that these costs should be borne by the beneficiaries of these projects and that **DP&L** is not one of these beneficiaries, any new credits or additional costs resulting from the ultimate outcome of this proceeding will be reflected in **DP&L's** TCRR rider which already includes these costs.
In connection with **DP&L** and other utilities joining PJM, in 2006 the FERC ordered utilities to eliminate certain charges to implement transitional payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, **DP&L** was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments. A hearing was held and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010 that substantially supports **DP&L's** and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. **DP&L**, along with other transmission owners in PJM and the Midwest Independent System Operator (MISO) made a compliance filing at FERC on August 19, 2010 that fully demonstrated all payment obligations to and from all parties within PJM and the MISO. The FERC has made no ruling regarding the compliance filing and some parties have requested rehearing by FERC of its May 21, 2010 order. It is expected that any order on the compliance filing and any order regarding the rehearing request will be appealed for Court review. Prior to this final order being issued, **DP&L** entered into a significant number of bi-lateral settlement agreements with certain parties to resolve the matter, which by design will be unaffected by the final decision. Further, in October 2010, **DP&L** entered into another settlement agreement to settle a portion of SECA amounts still owed to **DP&L**. With respect to unsettled claims, **DP&L** management believes it has deferred as a regulatory liability the appropriate amounts that are subject to refund (see SECA net revenue subject to refund within Note 3 of Notes to Consolidated Financial Statements) and therefore the results of this proceeding are not expected to have a material adverse effect on **DP&L's** results of operations.

NERC is a FERC-certified electric reliability organization responsible for developing and enforcing mandatory reliability standards including Critical Infrastructure Protection (CIP) reliability standards, across eight reliability regions. In June 2009, ReliabilityFirst Corporation (RFC), with responsibilities assigned to it by NERC over the reliability region that includes **DP&L**, commenced a routine audit of **DP&L's** operations. The audit, which was for the period June 18, 2007 to June 25, 2009, evaluated **DP&L's** compliance with 42 requirements in 18 NERC-reliability standards. **DP&L** is currently subject to a compliance audit at a minimum of once every three years as provided by the NERC Rules of Procedure. This audit was concluded in June 2009 and its findings revealed that **DP&L** had some Possible Alleged Violations (PAVs) associated with five NERC Reliability requirements of various Standards. In response to the report, **DP&L** filed mitigation plans with RFC/NERC to address the PAVs. These mitigation plans were accepted by RFC/NERC. In July 2010, **DP&L** negotiated a settlement with NERC wherein **DP&L** agreed to pay an immaterial amount in exchange for a resolution of all issues and obligations relating to the aforementioned PAVs. The settlement was approved on January 21, 2011 by the FERC.

17. Business Segments

During 2010, **DPL** began operating through two segments consisting of the operations of two of its wholly-owned subsidiaries, **DP&L** (Utility segment) and DPLER (Competitive Retail segment). Initiatives taken by state legislative bodies combined with changes in the market price of electricity have significantly impacted the manner in which electric utilities in certain parts of the United States, including Ohio, have traditionally conducted business. This has resulted in, among other things, a more competitive electricity marketplace. Accordingly, **DPL** increased its resources to participate in the more competitive retail electric service market. **DPL** believes that these reportable segments are consistent with how our management views its business and makes decisions on how to allocate resources and evaluate performance. Segment financial information for the periods 2009 and 2008 has been presented to conform to the 2010 disclosures, as required by GAAP.

The Utility segment is comprised of **DP&L's** electric generation, transmission and distribution businesses which generate and sell electricity to residential, commercial, industrial and governmental customers. Electricity for the segment's 24-county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers who are located in a 6,000 square mile area of West Central Ohio. **DP&L** also sells electricity to DPLER and any excess energy and capacity is sold into the wholesale market. **DP&L's** transmission and distribution businesses are subject to rate regulation by federal and state regulators while rates for its generation business are deemed competitive under Ohio law.

The Competitive Retail segment is comprised of DPLER's competitive retail electric service business which sells retail electric energy under contract primarily to commercial and industrial customers who have selected DPLER as their alternative electric supplier. The Competitive Retail segment sells electricity to approximately 9,000 customers currently located throughout Ohio. Due to increased competition in Ohio, during 2010 we increased the number of employees and resources assigned to manage DPLER and increased its marketing to customers. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L**. During 2010, we implemented a new wholesale agreement between **DP&L** and DPLER. Under this agreement, intercompany sales from **DP&L** to DPLER were based on the market prices for wholesale power. In periods prior to 2010, DPLER's purchases from **DP&L** were transacted at prices that approximated DPLER's sales prices to its end-use retail customers. The Competitive Retail segment has no transmission or generation assets.

Included within Other are other businesses that do not meet the GAAP requirements for disclosure as reportable segments as well as certain corporate costs which include interest expense on **DPL's** debt.

Management evaluates segment performance based on gross margin. The accounting policies of the reportable segments are the same as those described in Note 1 — Overview and Summary of Significant Accounting Policies. Intersegment sales and profits are eliminated in consolidation.

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The following table presents financial information for each of **DPL's** reportable business segments:

$ in millions		Utility		Competitive Retail		Other		Adjustments and Eliminations		DPL Consolidated
Year Ended December 31, 2010										
Revenues from external customers	$	1,552.0	$	277.0	$	54.1	$	—	$	1,883.1
Intersegment revenues		238.5		—		4.5		(243.0)		—
Total revenues	$	1,790.5	$	277.0	$	58.6	$	(243.0)	$	1,883.1
Purchased power		383.5		238.5		3.9		(238.5)		387.4
Gross margin		1,035.1		38.5		42.7		(4.5)		1,111.8
Depreciation and amortization		130.7		0.2		8.5		—		139.4
Interest expense		37.1		—		33.5		—		70.6
Income tax expense (benefit)		135.2		10.5		(2.7)		—		143.0
Net income (loss)		277.7		18.8		(3.5)		(2.7)		290.3
Total assets		3,475.4		35.7		302.2		—		3,813.3
Capital expenditures		148.2		—		3.2		—		151.4
Year Ended December 31, 2009										
Revenues from external customers	$	1,485.6	$	65.5	$	37.8	$	—	$	1,588.9
Intersegment revenues		64.8		—		3.8		(68.6)		—
Total revenues	$	1,550.4	$	65.5	$	41.6	$	(68.6)	$	1,588.9
Purchased power		259.2		64.8		1.0		(64.8)		260.2
Gross margin		967.6		0.7		33.7		(3.7)		998.3
Depreciation and amortization		135.5		0.1		9.9		—		145.5
Interest expense		38.5		—		44.5		—		83.0
Income tax expense (benefit)		124.5		(0.8)		(11.2)		—		112.5
Net income (loss)		258.9		(2.7)		(21.4)		(5.7)		229.1
Total assets		3,457.4		6.6		177.7		—		3,641.7
Capital expenditures		144.0		—		1.3		—		145.3
Year Ended December 31, 2008										
Revenues from external customers	$	1,422.3	$	150.8	$	28.5	$	—	$	1,601.6
Intersegment revenues		150.6		—		6.4		(157.0)		—
Total revenues	$	1,572.9	$	150.8	$	34.9	$	(157.0)	$	1,601.6
Purchased power		379.9		150.6		0.1		(153.3)		377.3
Gross margin		961.6		0.2		23.1		(3.7)		981.2
Depreciation and amortization		127.8		0.2		9.7		—		137.7
Interest expense		36.5		—		54.2		—		90.7
Income tax expense (benefit)		120.2		0.6		(17.9)		—		102.9
Net income (loss)		285.8		1.9		(37.6)		(5.6)		244.5
Total assets		3,397.7		13.5		225.8		—		3,637.0
Capital expenditures		225.4		—		2.4		—		227.8

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18. Subsequent Events

Contingent Redemption of DPL-Capital Trust II Securities

On January 26, 2011, **DPL** signed an agreement with a third party to acquire $122.1 million of outstanding DPL Capital Trust II 8.125% trust preferred securities. The sale to **DPL** is contingent upon the third party's ability to acquire the trust preferred securities.

In the event the third party is successful in acquiring the trust preferred securities, it has agreed to sell the trust preferred securities to **DPL** for a price of $134.3 million, plus any interest accrued through the date of closing. The closing is expected to occur on or before February 25, 2011. If this transaction closes, **DPL** expects to record a net loss on the reacquisition of the securities in the amount of approximately $15.3 million ($10.2 million net of tax) in the first quarter of 2011. Interest savings from the redemption of these securities are expected to be approximately $8.4 million ($5.6 million net of tax) for the remainder of 2011. **DPL** expects to finance this transaction using a combination of cash on hand and proceeds from the intended sale of some of its short-term investments.

In the event the third party is not able to acquire these securities, **DPL** will have no obligation to purchase these securities and will continue to carry these trust preferred securities as a long-term obligation on its Consolidated Balance Sheets.

19. Selected Quarterly Information (Unaudited)

DPL

	For the three months ended							
	March 31,		June 30,		September 30,		December 31,	
$ in millions except per share amount and common stock market price	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Revenues	**$ 451.2**	$ 415.0	**$ 445.5**	$ 361.2	**$ 516.9**	$ 407.3	**$ 469.5**	$ 405.4
Operating income	**$ 126.0**	$ 127.0	**$ 109.3**	$ 81.9	**$ 144.6**	$ 116.5	**$ 124.5**	$ 102.8
Net income	**$ 71.0**	$ 69.2	**$ 61.4**	$ 42.1	**$ 86.4**	$ 67.9	**$ 71.5**	$ 49.9
Earnings per share of common stock:								
Basic	**$ 0.61**	$ 0.62	**$ 0.53**	$ 0.38	**$ 0.75**	$ 0.60	**$ 0.62**	$ 0.43
Diluted	**$ 0.61**	$ 0.61	**$ 0.53**	$ 0.37	**$ 0.74**	$ 0.59	**$ 0.62**	$ 0.43
Dividends declared and paid per share	**$0.3025**	$0.2850	**$0.3025**	$0.2850	**$0.3025**	$0.2850	**$0.3025**	$0.2850
Common stock market price - High	**$ 28.47**	$ 23.28	**$ 28.18**	$ 23.46	**$ 26.65**	$ 26.53	**$ 27.51**	$ 28.68
- Low	**$ 26.51**	$ 19.27	**$ 23.80**	$ 21.18	**$ 23.95**	$ 22.79	**$ 25.33**	$ 25.16

DP&L

	For the three months ended							
	March 31,		June 30,		September 30,		December 31,	
$ in millions	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Revenues	**$ 438.0**	$ 403.6	**$ 423.9**	$ 351.9	**$ 487.0**	$ 398.2	**$ 441.6**	$ 396.7
Operating income	**$ 118.4**	$ 124.8	**$ 97.0**	$ 78.9	**$ 131.9**	$ 115.2	**$ 102.9**	$ 103.0
Net income	**$ 72.1**	$ 77.0	**$ 59.4**	$ 46.8	**$ 83.2**	$ 74.0	**$ 63.0**	$ 61.1
Earnings on common stock	**$ 71.9**	$ 76.8	**$ 59.2**	$ 46.6	**$ 83.0**	$ 73.8	**$ 62.7**	$ 60.8
Dividends paid on common stock to parent	**$ 90.0**	$ 175.0	**$ 60.0**	$ 45.0	**$ —**	$ 50.0	**$ 150.0**	$ 55.0

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
DPL Inc.:

We have audited the accompanying Consolidated Balance Sheets of DPL Inc. and subsidiaries (the Company) as of December 31, 2010 and 2009, and the related Consolidated Statements of Results of Operations, Shareholders' Equity and Cash Flows for each of the years in the three-year period ended December 31, 2010. In connection with our audits of the consolidated financial statements, we have audited the consolidated financial statement schedule, "Schedule II — Valuation and Qualifying Accounts." We also have audited the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these consolidated financial statements, the financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these consolidated financial statements, the financial statement schedule, and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles, and the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Philadelphia, Pennsylvania
February 17, 2011

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholder
The Dayton Power and Light Company:

We have audited the accompanying Balance Sheets of The Dayton Power and Light Company (DP&L) as of December 31, 2010 and 2009, and the related Statements of Results of Operations, Shareholder's Equity and Cash Flows for each of the years in the three-year period ended December 31, 2010. In connection with our audits of the financial statements, we also have audited the financial statement schedule, "Schedule II — Valuation and Qualifying Accounts." These financial statements and the financial statement schedule are the responsibility of DP&L's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinions.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of DP&L as of December 31, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

Philadelphia, Pennsylvania
February 17, 2011

Item 9 —Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
None.
Item 9A — Controls and Procedures
Disclosure Controls and Procedures
Our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) are responsible for establishing and maintaining our disclosure controls and procedures. These controls and procedures were designed to ensure that material information relating to us and our subsidiaries are communicated to the CEO and CFO. We evaluated these disclosure controls and procedures as of the end of the period covered by this report with the participation of our CEO and CFO. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective: (i) to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms; and (ii) to ensure that information required to be disclosed by us in the reports that we submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.
There was no change in our internal control over financial reporting during the most recently completed fiscal period that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.
The following report is our report on internal control over financial reporting as of December 31, 2010.
Management's Report on Internal Control over Financial Reporting
We are responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including the CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on an evaluation under the framework in *Internal Control - Integrated Framework*, we concluded that our internal control over financial reporting was effective as of December 31, 2010.
Our internal control over financial reporting as of December 31, 2010, has been audited by KPMG LLP, the independent registered public accounting firm that audited the financial statements contained herein, as stated in their report which is included herein.
Item 9B — Other Information
None.

PART III

Item 10 — Directors, Executive Officers and Corporate Governance

The information required to be furnished pursuant to this item with respect to Directors and Executive Officers of **DPL** will be set forth under the captions "Election of Directors" and "Executive Officers" in **DPL's** proxy statement (the Proxy Statement) to be furnished to shareholders in connection with the solicitation of proxies by our Board of Directors for use at the 2011 Annual Meeting of Shareholders to be held on April 27, 2011 and is incorporated herein by reference.

The information required to be furnished pursuant to this item for **DPL** with respect to Section 16(a) Beneficial Ownership Reporting Compliance, the Audit Committee, the Audit Committee financial expert and the registrant's code of ethics will be set forth under in the "Corporate Governance" section in the Proxy Statement and is incorporated herein by reference.

Item 11 — Executive Compensation

The information required to be furnished pursuant to this item for **DPL** will be set forth under the captions "Executive Compensation," "Compensation Discussion and Analysis (CD&A)" and "Compensation Committee Report on Executive Compensation" in the Proxy Statement and is incorporated herein by reference.

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

The information required to be furnished pursuant to this item for **DPL** will be set forth under the captions "Security Ownership of Certain Beneficial Owners," "Security Ownership of Management" and "Equity Compensation Plan Information" in the Proxy Statement and is incorporated herein by reference.

Item 13 — Certain Relationships and Related Transactions, and Director Independence

The information required to be furnished pursuant to this item for **DPL** will be set forth under the caption "Related Person Transactions" and "Independence" in the Proxy Statement and is incorporated herein by reference.

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Item 14 — Principal Accountant Fees and Services

The information required to be furnished pursuant to this item for **DPL** will be set forth under the caption "Audit and Non-Audit Fees" in the Proxy Statement and is incorporated herein by reference.

Accountant Fees and Services

The following table presents the aggregate fees billed for professional services rendered to **DPL** and **DP&L** by KPMG LLP for 2010 and 2009. Other than as set forth below, no professional services were rendered or fees billed by KPMG LLP during 2010 and 2009.

KPMG LLP	2010 Fees Billed	2009 Fees Billed
Audit Fees (1)	$ 1,269,200	$ 1,394,680
Audit-Related Fees (2)	40,000	46,000
Tax Fees (3)	930	7,870
All Other Fees (4)	15,000	—
Total	$ 1,325,130	$ 1,448,550

(1) Audit fees relate to professional services rendered for the audit of our annual financial statements and the reviews of our quarterly financial statements.

(2) Audit-related fees relate to services rendered to us for assurance and related services.

(3) Tax fees consisted principally of tax compliance services. Tax compliance services are services rendered based upon facts already in existence or transactions that have already occurred to document, compute, and obtain government approval for amounts to be included in tax filings.

(4) Other fees relate to services rendered under an agreed upon procedure engagement related to environmental studies.

PART IV

Item 15 — Exhibits and Financial Statement Schedules

The information required to be submitted in Schedules I, III, IV and V is omitted as not applicable or not required under rules of Regulation S-X.

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3. **Exhibits**

DPL and **DP&L** exhibits are incorporated by reference as described unless otherwise filed as set forth herein. The exhibits filed as part of **DPL's** and **DP&L's** Annual Report on Form 10-K, respectively, are:

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
X		3(a)	Amended Articles of Incorporation of DPL Inc., as of September 25, 2001	Exhibit 3 to Report on Form 10-K/A for the year ended December 31, 2001 (File No. 1-9052)
X		3(b)	Amended Regulations of DPL Inc., as of April 27, 2007	Exhibit 3(b) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
	X	3(c)	Amended Articles of Incorporation of The Dayton Power and Light Company, as of January 4, 1991	Exhibit 3(b) to Report on Form 10-K/A for the year ended December 31, 1991 (File No. 1-2385)
	X	3(d)	Regulations of The Dayton Power and Light Company, as of April 9, 1981	Exhibit 3(a) to Report on Form 8-K filed on May 3, 2004 (File No. 1-2385)
X	X	4(a)	Composite Indenture dated as of October 1, 1935, between The Dayton Power and Light Company and Irving Trust Company, Trustee with all amendments through the Twenty-Ninth Supplemental Indenture	Exhibit 4(a) to Report on Form 10-K for the year ended December 31, 1985 (File No. 1-2385)
X	X	4(b)	Forty-First Supplemental Indenture dated as of February 1, 1999, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4(m) to Report on Form 10-K for the year ended December 31, 1998 (File No. 1-2385)
X	X	4(c)	Forty-Second Supplemental Indenture dated as of September 1, 2003, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4(r) to Report on Form 10-K for the year ended December 31, 2003 (File No. 1-9052)
X	X	4(d)	Forty-Third Supplemental Indenture dated as of August 1, 2005, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4.4 to Report on Form 8-K filed August 24, 2005 (File No. 1-2385)
X	X	4(e)	Rights Agreement dated September 25, 2001 between DPL Inc. and Equiserve Trust Company, N.A.	Exhibit 4 to Report on Form 8-K filed September 28, 2001 (File No. 1-9052)

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DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
X		4(f)	Securities Purchase Agreement dated as of February 1, 2000 by and among DPL Inc., and DPL Capital Trust I, Dayton Ventures LLC and Dayton Ventures, Inc. and certain exhibits thereto	Exhibit 99(b) to Schedule TO-I filed February 4, 2000 (File No. 1-9052)
X		4(g)	Amendment to Securities Purchase Agreement dated as of February 24, 2000 among DPL Inc., DPL Capital Trust I, Dayton Ventures LLC and Dayton Ventures, Inc.	Exhibit 4(g) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X		4(h)	Form of Warrant to Purchase Common Shares of DPL Inc.	Exhibit 4(h) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X		4(i)	Securityholders and Registration Rights Agreement dated as of March 13, 2000 among DPL Inc., DPL Capital Trust I, Dayton Ventures LLC and Dayton Ventures, Inc.	Exhibit 4(i) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X		4(j)	Amendment to Securityholders and Registration Rights Agreement, dated August 24, 2001 among DPL Inc., DPL Capital Trust I, Dayton Ventures LLC and Dayton Ventures, Inc.	Exhibit 4(j) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X		4(k)	Amendment to Securityholders and Registration Rights Agreement, dated December 6, 2004 among DPL Inc., DPL Capital Trust I, Dayton Ventures LLC and Dayton Ventures, Inc.	Exhibit 4(k) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X		4(l)	Amendment to Securityholders and Registration Rights Agreement, dated as of January 12, 2005 among DPL Inc., DPL Capital Trust I, Dayton Ventures LLC and Dayton Ventures, Inc	Exhibit 4(j) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X		4(m)	Indenture dated as of March 1, 2000 between DPL Inc. and Bank One Trust Company, National Association	Exhibit 4(b) to Registration Statement No. 333-37972

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DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
X		4(n)	Exchange and Registration Rights Agreement dated as of August 24, 2001 between DPL Inc., Morgan Stanley & Co. Incorporated, Bank One Capital Markets, Inc., Fleet Securities, Inc. and NatCity Investments, Inc.	Exhibit 4(a) to Registration Statement No. 333-74568
X		4(o)	Officer's Certificate of DPL Inc. establishing exchange notes, dated August 31, 2001	Exhibit 4(c) to Registration Statement No. 333-74568
X		4(p)	Indenture dated as of August 31, 2001 between DPL Inc. and The Bank of New York, Trustee	Exhibit 4(a) to Registration Statement No. 333-74630
X		4(q)	First Supplemental Indenture dated as of August 31, 2001 between DPL Inc. and The Bank of New York, as Trustee	Exhibit 4(b) to Registration Statement No. 333-74630
X		4(r)	Amended and Restated Trust Agreement dated as of August 31, 2001 among DPL Inc., The Bank of New York, The Bank of New York (Delaware), the administrative trustees named therein, and several Holders as defined therein	Exhibit 4(c) to Registration Statement No. 333-74630
	X	4(s)	Forty-Fourth Supplemental Indenture dated as of September 1, 2006 between the Bank of New York, Trustee and The Dayton Power and Light Company	Exhibit 4(s) to Report on Form 10-K for the year ended December 31, 2009 (File No. 1-2385)
X		4(t)	Exchange and Registration Rights Agreement dated as of August 24, 2001 among DPL Inc., DPL Capital Trust II and Morgan Stanley & Co. Incorporated	Exhibit 4(d) to Registration Statement No. 333-74630
X	X	4(u)	Forty-Sixth Supplemental Indenture dated as of December 1, 2008 between The Bank of New York Mellon, Trustee and The Dayton Power and Light Company	Exhibit 4(x) to Report on Form 10-K for the year ended December 31, 2008 (File No. 1-2385)

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
X	X	10(a)*	The Dayton Power and Light Company Directors' Deferred Stock Compensation Plan, as amended through December 31, 2000	Exhibit 10(a) to Report on Form 10-K for the year ended December 31, 2000 (File No. 1-9052)
X	X	10(b)*	The Dayton Power and Light Company 1991 Amended Directors' Deferred Compensation Plan, as amended and restated through December 31, 2007	Exhibit 10(b) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X	X	10(c)*	The Dayton Power and Light Company Management Stock Incentive Plan as amended and restated through December 31, 2007	Exhibit 10(c) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X	X	10(d)*	The Dayton Power and Light Company Key Employees Deferred Compensation Plan, as amended through December 31, 2000	Exhibit 10(d) to Report on Form 10-K for the year ended December 31, 2000 (File No. 1-9052)
X	X	10(e)*	Amendment No. 1 to The Dayton Power and Light Company Key Employees Deferred Compensation Plan, as amended through December 31, 2000, dated as of December 7, 2004	Exhibit 10(g) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X	X	10(f)*	The Dayton Power and Light Company Supplemental Executive Retirement Plan, as amended February 1, 2000	Exhibit 10(f) to Report on Form 10-K for the year ended December 31, 2009 (File No. 1-9052)
X	X	10(g)*	Amendment No. 1 to The Dayton Power and Light Company Supplemental Executive Retirement Plan, as amended through February 1, 2000 and dated as of December 7, 2004	Exhibit 10(i) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X		10(h)*	DPL Inc. Stock Option Plan	Exhibit 10(f) to Report on Form 10-K for the year ended December 31, 2000 (File No. 1-9052)
X		10(i)*	2003 Long-Term Incentive Plan of DPL Inc.	Exhibit 10(aa) to Report on Form 10-K for the year ended December 31, 2003 (File No. 1-9052)

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
X	X	10(j)*	Summary of Executive Medical Insurance Plan	Exhibit 10(m) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X		10(k)*	DPL Inc. Executive Incentive Compensation Plan, as amended and restated through December 31, 2007	Exhibit 10(l) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X		10(l)*	DPL Inc. 2006 Equity and Performance Incentive Plan as amended and restated through December 31, 2007	Exhibit 10(m) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X		10(m)*	Form of DPL Inc. Amended and Restated Long-Term Incentive Plan - Performance Shares Agreement	Exhibit 10(n) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X		10(n)*	DPL Inc. Severance Pay and Change of Control Plan, as amended and restated through December 31, 2007	Exhibit 10(o) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X		10(o)*	DPL Inc. Supplemental Executive Defined Contribution Retirement Plan, as amended and restated through December 31, 2007	Exhibit 10(p) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X		10(p)*	DPL Inc. 2006 Deferred Compensation Plan For Executives, as amended and restated through December 31, 2007	Exhibit 10(q) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X		10(q)*	DPL Inc. Pension Restoration Plan, as amended and restated through December 31, 2007	Exhibit 10(r) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X	X	10(r)*	Participation Agreement dated August 2, 2007 among DPL Inc., The Dayton Power and Light Company and Teresa F. Marrinan	Exhibit 10(s) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X	X	10 (s)*	Participation Agreement dated March 27, 2007 among DPL Inc., The Dayton Power and Light Company and Scott J. Kelly	Exhibit 10(t) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
X	X	10(t)*	Participation Agreement and Waiver dated February 27, 2006 among DPL Inc., The Dayton Power and Light Company and Gary G. Stephenson	Exhibit 10(u) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X	X	10 (u)*	Participation Agreement dated January 13, 2007 among DPL Inc., The Dayton Power and Light Company and Daniel J. McCabe	Exhibit 10(x) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X		10(v)*	Management Stock Option Agreement dated as of January 1, 2001 between DPL Inc. and Arthur G. Meyer	Exhibit 10(cc) to Report on Form 10-K for the year ended December 31, 2005 (File No. 1-9052)
X	X	10(w)*	Participation Agreement and Waiver dated March 6, 2006 among DPL Inc., The Dayton Power and Light Company and Arthur G. Meyer, dated March 6, 2006	Exhibit 10(w) to Report on Form 10-K for the year ended December 31, 2009 (File No. 1-9052)
X	X	10(x)*	Participation Agreement dated September 8, 2006 among DPL Inc., The Dayton Power and Light Company and Paul M. Barbas	Exhibit 10.2 to Form 8-K filed September 8, 2006 (File No. 1-9052)
X	X	10(y)*	Participation Agreement dated June 30, 2006 among DPL Inc., The Dayton Power and Light Company and Frederick J. Boyle	Exhibit 10.1 to Form 8-K filed July 3, 2006 (File No. 1-9052)
X		10(z)*	Letter Agreement between DPL Inc. and Glenn E. Harder, dated June 20, 2006	Exhibit 10.1 to Form 8-K filed June 21, 2006 (File No. 1-9052)

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
X	X	10(aa)	Credit Agreement, dated as of November 21, 2006 among The Dayton Power and Light Company, KeyBank National Association and certain lending institutions, and Amendment No. 1 to Credit Agreement, dated as of April 9, 2009	Exhibit 10(aa) to Report on Form 10-K for the year ended December 31, 2009 (File No. 1-2385)
X	X	10(bb)	Credit Agreement, dated as of April 21, 2009 by and among The Dayton Power and Light Company and the lenders party thereto and PNC Bank, National Association	Exhibit 10.1 to Form 8-K filed October 8, 2009 (File No. 1-2385)
X		10(cc)*	Form of DPL Inc. Amended and Restated Non-Employee Director Restricted Stock Units Agreement	Exhibit 10(uu) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X		10(dd)*	DPL Inc. 2006 Deferred Compensation Plan for Non-Employee Directors, as amended and restated through December 31, 2007	Exhibit 10(v v) to Report on Form 10-K for the year ended December 31, 2007 (File No. 1-9052)
X	X	10(ee)*	Separation Agreement dated as of September 17, 2010, by and between DPL Inc. and The Dayton Power and Light Company and Douglas C. Taylor	Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2010 (File No. 1-9052)
X		10(ff)*	Restricted Stock Agreement dated May 6, 2008 by and between DPL Inc. and Paul M. Barbas	Exhibit 99.1 to Form 8-K filed May 8, 2008 (File No. 1-9052)
X		10(gg)*	Form of DPL Inc. Restricted Stock Agreement	Exhibit 10(d) to Report on Form 10-Q for the quarter ended June 30, 2009 (File No. 1-9052)
X		10(hh)*	Form of DPL Inc. 2009 Career Grant and Matching Restricted Stock Agreement	Exhibit 10(b) to Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 1-9052)
X	X	10(ii)*	Participation Agreement dated May 18, 2009, among DPL Inc., The Dayton Power and Light Company and Joseph W. Mulpas	Exhibit 10(c) to Report on Form 10-Q for the quarter ended June 30, 2009 (File No. 1-9052)

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
X	X	10(jj)*	Credit Agreement, dated as of April 20, 2010, among the Dayton Power and Light Company, Bank of America, N.A., as Administrative Agent and an L/C Issuer, PNC Capital Markets, LLC and U.S. Bank, National Association, as Co-Syndication Agents, and the other lenders party to the Credit Agreement	Exhibit 10.1 to Form 8-K filed April 22, 2010 (File No. 1-2385)
X	X	10(kk)*	Participation Agreement dated May 14, 2010, among DPL Inc., The Dayton Power and Light Company and Bryce W. Nickel	Exhibit 10(b) to Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-9052)
X	X	10(ll)*	Participation Agreement dated May 14, 2010, among DPL Inc., The Dayton Power and Light Company and Kevin W. Crawford	Exhibit 10(c) to Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-9052)
X	X	10(mm)*	Participation Agreement dated February 3, 2011, among DPL Inc., The Dayton Power and Light Company and Craig L. Jackson	Filed herewith as Exhibit 10(mm)
X	X	21	List of Subsidiaries of DPL Inc. and The Dayton Power and Light Company	Filed herewith as Exhibit 21
X		23(a)	Consent of KPMG LLP	Filed herewith as Exhibit 23(a)
X		31(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(a)
X		31(b)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(b)
	X	31(c)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(c)
	X	31(d)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(d)
X		32(a)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(a)
X		32(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(b)

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DPL Inc.	DP&L	Exhibit Number	Exhibit	Location(1)
	X	32(c)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(c)
	X	32(d)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(d)
X	X	101.INS	XBRL Instance	Furnished herewith as Exhibit 101.INS
X	X	101.SCH	XBRL Taxonomy Extension Schema	Furnished herewith as Exhibit 101.SCH
X	X	101.CAL	XBRL Taxonomy Extension Calculation Linkbase	Furnished herewith as Exhibit 101.CAL
X	X	101.DEF	XBRL Taxonomy Extension Definition Linkbase	Furnished herewith as Exhibit 101.DEF
X	X	101.LAB	XBRL Taxonomy Extension Label Linkbase	Furnished herewith as Exhibit 101.LAB
X	X	101.PRE	XBRL Taxonomy Extension Presentation Linkbase	Furnished herewith as Exhibit 101.PRE

* Management contract or compensatory plan

Exhibits referencing File No. 1-9052 have been filed by DPL Inc. and those referencing File No. 1-2385 have been filed by The Dayton Power and Light Company.

Pursuant to paragraph (b) (4) (iii) (A) of Item 601 of Regulation S-K, we have not filed as an exhibit to this Form 10-K certain instruments with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of us and our subsidiaries on a consolidated basis, but we hereby agree to furnish to the SEC on request any such instruments.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, **DPL Inc.** and **The Dayton Power and Light Company** has duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized.

		DPL Inc.
February 17, 2011	By:	
		/s/ Paul M. Barbas
		Paul M. Barbas President and Chief Executive Officer (principal executive officer)
		The Dayton Power and Light Company
February 17, 2011	By:	
		/s/ Paul M. Barbas
		Paul M. Barbas President and Chief Executive Officer (principal executive officer)

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of **DPL Inc.** and **The Dayton Power and Light Company** and in the capacities and on the dates indicated.

/s/ P.M. Barbas (P.M. Barbas)	Director, President and Chief Executive Officer (principal executive officer)	February 16, 2011
/s/ R.D. Biggs (R. D. Biggs)	Director	February 16, 2011
/s/ P.R. Bishop (P. R. Bishop)	Director and Vice-Chairman	February 16, 2011
/s/ F.F. Gallaher (F.F. Gallaher)	Director	February 16, 2011
/s/ B.S. Graham (B. S. Graham)	Director	February 16, 2011
/s/ G.E. Harder (G.E. Harder)	Director and Chairman	February 16, 2011
/s/ P.B. Morris (P.B. Morris)	Director	February 16, 2011
/s/ N.J. Sifferlen (N.J. Sifferlen)	Director	February 16, 2011
/s/ F.J. Boyle (F.J. Boyle)	Senior Vice President and Chief Financial Officer (principal financial officer)	February 16, 2011
/s/ J.W. Mulpas (J.W. Mulpas)	Vice President, Controller and Chief Accounting Officer (principal accounting officer)	February 16, 2011

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Schedule II

DPL Inc.

VALUATION AND QUALIFYING ACCOUNTS

For the years ended December 31, 2008 - 2010

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions (1)	Balance at End of Period
2010:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,101	$ 4,148	$ 4,378	$ 871
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ 11,955	$ 1,124	$ —	$ 13,079
2009:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,084	$ 5,168	$ 5,151	$ 1,101
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ 10,685	$ 1,270	$ —	$ 11,955
2008:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,518	$ 4,277	$ 4,711	$ 1,084
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ 12,429	$ 1,482	$ 3,226	$ 10,685

(1) Amounts written off, net of recoveries of accounts previously written off.

The Dayton Power and Light Company

VALUATION AND QUALIFYING ACCOUNTS

For the years ended December 31, 2008 - 2010

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions (1)	Balance at End of Period
2010:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,101	$ 4,100	$ 4,369	$ 832
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —
2009:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,084	$ 5,168	$ 5,151	$ 1,101
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ —	$ —	$ —	$ —
2008:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,518	$ 4,277	$ 4,711	$ 1,084
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ 348	$ —	$ 348	$ —

(1) Amounts written off, net of recoveries of accounts previously written off.

Exhibit KMM-19

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(x) QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **September 30, 2012**

OR

( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-9052	**DPL INC.** (An Ohio Corporation) 1065 Woodman Drive Dayton, Ohio 45432 937-224-6000	**31-1163136**
1-2385	**THE DAYTON POWER AND LIGHT COMPANY** (An Ohio Corporation) 1065 Woodman Drive Dayton, Ohio 45432 937-224-6000	**31-0258470**

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

DPL Inc.	Yes [ ]	No [X]
The Dayton Power and Light Company	Yes [ ]	No [X]

(The Dayton Power and Light Company is a voluntary filer that has filed all applicable reports under Section 13 or 15(d) of the Securities Exchange Act of 1934 in the preceding 12 months. On September 10, 2012, DPL Inc.'s Registration Statement on form S-4 was declared effective, and thus DPL Inc. is now required to file reports pursuant to Section 15(d); however, DPL Inc. has not been subject to such filing requirement for the past 90 days.)

Indicate by check mark whether each registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

DPL Inc.	Yes [X]	No [ ]
The Dayton Power and Light Company	Yes [X]	No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
DPL Inc.	[ ]	[ ]	[X]	[ ]
The Dayton Power and Light Company	[ ]	[ ]	[X]	[ ]

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

DPL Inc.	Yes [ ]	No [X]
The Dayton Power and Light Company	Yes [ ]	No [X]

All of the outstanding common stock of DPL Inc. is indirectly owned by The AES Corporation. All of the common stock of The Dayton Power and Light Company is owned by DPL Inc.

As of September 30, 2012, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares Outstanding
DPL Inc.	**Common Stock, no par value**	**1**
The Dayton Power and Light Company	**Common Stock, $0.01 par value**	**41,172,173**

Documents incorporated by reference: **None**

This combined Form 10-Q is separately filed by DPL Inc. and The Dayton Power and Light Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to a registrant other than itself.

DPL Inc. and The Dayton Power and Light Company

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DPL Inc. and The Dayton Power and Light Company

Index (cont.)

GLOSSARY OF TERMS

The following select abbreviations or acronyms are used in this Form 10-Q:

Abbreviation or Acronym	Definition

AES	The AES Corporation, a global power company, the ultimate parent company of **DPL**
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CFTC	Commodity Futures Trading Commission
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CSAPR	Cross-State Air Pollution Rule
CSP	Columbus Southern Power Company, a subsidiary of American Electric Power Company, Inc. ("AEP"). Columbus Southern Power Company merged into the Ohio Power Company, another subsidiary of AEP, effective December 31, 2011
CO_2	Carbon Dioxide
CCEM	Customer Conservation and Energy Management
CRES	Competitive Retail Electric Service
DPL	DPL Inc.
DPLE	DPL Energy, LLC, a wholly owned subsidiary of **DPL** that owns and operates peaking generation facilities from which it makes wholesale sales
DPLER	DPL Energy Resources, Inc., a wholly owned subsidiary of **DPL** which sells competitive electric energy and other energy services
DP&L	The Dayton Power and Light Company, the principal subsidiary of **DPL** and a public utility which sells electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio
Duke Energy	Duke Energy Ohio, Inc., formerly The Cincinnati Gas & Electric Company (CG&E)
EIR	Environmental Investment Rider
EPS	Earnings Per Share
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plans, filed with the PUCO, pursuant to Ohio law
ESP Stipulation	A Stipulation and Recommendation filed by **DP&L** with the PUCO on February 24, 2009 regarding **DP&L's** ESP filing pursuant to SB 221. The Stipulation was signed by the Staff of the PUCO, the Office of the Ohio Consumers' Counsel and various intervening parties. The PUCO approved the Stipulation on June 24, 2009.
FASB	Financial Accounting Standards Board
FASC	FASB Accounting Standards Codification
FASC 805	FASB Accounting Standards Codification 805, "Business Combinations"

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Form 10-K	**DPL's** and **DP&L's** combined Annual Report on Form 10-K/A for the fiscal year ending December 31, 2011, which was filed on March 28, 2012
FTRs	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
kWh	Kilowatt hours
MC Squared	MC Squared Energy Services, LLC, a retail electricity supplier wholly owned by DPLER which was purchased on February 28, 2011
Merger	The merger of **DPL** and Dolphin Sub, Inc. (a wholly owned subsidiary of AES)

	in accordance with the terms of the Merger agreement. At the Merger date, Dolphin Sub, Inc. was merged into **DPL**, leaving **DPL** as the surviving company. As a result of the Merger, **DPL** became a wholly owned subsidiary of AES.
Merger agreement	The Agreement and Plan of Merger dated April 19, 2011 among **DPL**, The AES Corporation ("AES"), and Dolphin Sub, Inc., a wholly owned subsidiary of AES, whereby AES agreed to acquire **DPL** for $30 per share in a cash transaction valued at approximately $3.5 billion plus the assumption of $1.2 billion of existing debt. Upon closing, **DPL** became a wholly owned subsidiary of AES.
Merger date	November 28, 2011, the date of the closing of the merger of **DPL** and Dolphin Sub, Inc., a wholly owned subsidiary of AES.
MRO	Market Rate Option, a plan available to be filed with the PUCO pursuant to Ohio law
MTM	Mark to Market
MVIC	Miami Valley Insurance Company, a wholly owned insurance subsidiary of **DPL** that provides insurance services to **DPL** and its subsidiaries and, in some cases, insurance services to partner companies related to jointly owned facilities operated by **DP&L**
NERC	North American Electric Reliability Corporation
Non-bypassable	Charges that are assessed to all customers regardless of whom the customer selects to supply its retail electric service
NOV	Notice of Violation
NOx	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority
Ohio EPA	Ohio Environmental Protection Agency
OTC	Over-The-Counter
OVEC	Ohio Valley Electric Corporation, an electric generating company in which **DP&L** holds a 4.9% equity interest

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
PJM	PJM Interconnection, LLC, a regional transmission organization
Predecessor	**DPL** prior to November 28, 2011, the date AES acquired **DPL**
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
RSU	Restricted Stock Units
RTO	Regional Transmission Organization
RPM	Reliability Pricing Model
SB 221	Ohio Senate Bill 221, an Ohio electric energy bill that was signed by the Governor on May 1, 2008 and went into effect July 31, 2008. This law required all Ohio distribution utilities to file either an ESP or MRO to be in effect January 1, 2009. The law also contains, among other things, annual targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SECA	Seams Elimination Charge Adjustment
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SSO	Standard Service Offer which represents the regulated rates, authorized by the

PUCO, charged to **DP&L** retail customers within **DP&L's** service territory

Successor... **DPL** after its acquisition by AES
TCRR... Transmission Cost Recovery Rider
USEPA .... U.S. Environmental Protection Agency
USF .... Universal Service Fund
VRDN .... Variable Rate Demand Note

This report includes the combined filing of **DPL** and **DP&L**. On November 28, 2011, **DPL** became a wholly owned subsidiary of AES, a global power company. Throughout this report, the terms "we," "us," "our" and "ours" are used to refer to both **DPL** and **DP&L**, respectively and altogether, unless the context indicates otherwise. Discussions or areas of this report that apply only to **DPL** or **DP&L** will clearly be noted in the section.

FORWARD-LOOKING STATEMENTS

This report includes certain "forward-looking statements" that involve many risks and uncertainties. Forward-looking statements express an expectation or belief and contain a projection, plan or assumption with regard to, among other things, our future revenues, income, expenses or capital structure. Such statements of future events or performance are not guarantees of future performance and involve estimates, assumptions and uncertainties. The words "could," "may," "predict," "anticipate," "would," "believe," "estimate," "expect," "forecast," "project," "objective," "intend," "continue," "should," "plan," and similar expressions, or the negatives thereof, are intended to identify forward-looking statements unless the context requires otherwise. These forward-looking statements are based on management's present expectations and beliefs about future events. As with any projection or forecast, these statements are inherently susceptible to uncertainty and changes in circumstances. We are under no obligation to, and expressly disclaim any obligation to, update or alter the forward-looking statements whether as a result of such changes, new information, subsequent events or otherwise. If we do update one or more forward-looking statements, no inference should be made that we will make additional updates with respect to those or other forward-looking statements.

Important factors that could cause actual results to differ materially from those reflected in such forward-looking statements and that should be considered in evaluating our outlook include, but are not limited to, the following:

- abnormal or severe weather and catastrophic weather-related damage;
- unusual maintenance or repair requirements;
- changes in fuel costs and purchased power, coal, environmental emissions, natural gas and other commodity prices;
- volatility and changes in markets for electricity and other energy-related commodities;
- performance of our suppliers;
- increased competition and deregulation in the electric utility industry;
- increased competition in the retail generation market;
- changes in interest rates;
- state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, emission levels, rate structures or tax laws;
- changes in environmental laws and regulations to which **DPL** and its subsidiaries are subject;
- the development and operation of RTOs, including PJM to which **DPL's** operating subsidiary (**DP&L**) has given control of its transmission functions;
- changes in our purchasing processes, pricing, delays, contractor and supplier performance and availability;
- significant delays associated with large construction projects;
- growth in our service territory and changes in demand and demographic patterns;
- changes in accounting rules and the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- financial market conditions;
- the outcomes of litigation and regulatory investigations, proceedings or inquiries;
- costs related to the Merger and the effects of any disruption from the Merger that may make it more difficult to maintain relationships with employees, customers, other business partners or government entities; and

- general economic conditions.

All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and many are beyond our control. See "Risk Factors" for a more detailed discussion of the foregoing and certain other factors that could cause actual results to differ materially from those reflected in such forward-looking statements and that should be considered in evaluating our outlook.

You may read and copy any document we file at the SEC's public reference room located at 100 F Street N.E., Washington, D.C. 20549, USA. Please call the SEC at (800) SEC-0330 for further information on the public reference room. Our SEC filings are also available to the public from the SEC's website at http://www.sec.gov.

COMPANY WEBSITES

DPL's public internet site is http://www.dplinc.com. **DP&L's** public internet site is http://www.dpandl.com. The information on these websites is not incorporated by reference into this report.

Part I – Financial Information

This report includes the combined filing of **DPL** and **DP&L**. Throughout this report, the terms "we," "us," "our" and "ours" are used to refer to both **DPL** and **DP&L**, respectively and altogether, unless the context indicates otherwise. Discussions or areas of this report that apply only to **DPL** or **DP&L** will clearly be noted in the section.

Item 1 – Financial Statements

FINANCIAL STATEMENTS

DPL INC.

DPL INC.

CONDENSED CONSOLIDATED STATEMENTS OF RESULTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	**2012**	2011
$ in millions except per share amounts	**Successor**	Predecessor	**Successor**	Predecessor
Revenues	**$ 471.7**	$ 497.6	**$ 1,287.7**	$ 1,411.5
Cost of revenues:				
Fuel	**112.7**	129.0	**279.0**	320.9
Purchased power	**90.7**	108.3	**265.8**	342.7
Amortization of intangibles	**24.2**	-	**71.2**	-
Total cost of revenues	**227.6**	237.3	**616.0**	663.6
Gross margin	**244.1**	260.3	**671.7**	747.9
Operating expenses:				
Operation and maintenance	**106.6**	92.0	**312.1**	298.2
Depreciation and amortization	**33.1**	35.8	**95.6**	106.0
General taxes	**15.7**	19.6	**58.7**	64.2
Goodwill impairment	**1,850.0**	-	**1,850.0**	-
Total operating expenses	**2,005.4**	147.4	**2,316.4**	468.4
Operating income / (loss)	**(1,761.3)**	112.9	**(1,644.7)**	279.5
Other income / (expense), net:				
Investment income	**1.9**	0.1	**2.2**	0.3
Interest expense	**(31.1)**	(16.8)	**(93.1)**	(51.3)
Charge for early redemption of debt	**-**	-	**-**	(15.3)
Other expense	**(0.2)**	(0.5)	**(1.4)**	(1.2)
Total other income / (expense), net	**(29.4)**	(17.2)	**(92.3)**	(67.5)
Earnings / (loss) before income tax	**(1,790.7)**	95.7	**(1,737.0)**	212.0
Income tax expense	**20.2**	28.6	**40.3**	69.7
Net income / (loss)	**$ (1,810.9)**	$ 67.1	**$ (1,777.3)**	$ 142.3

Average number of common shares outstanding (millions):				
Basic	N/A	115.0	N/A	114.4
Diluted	N/A	115.5	N/A	115.0
Earnings per share of common stock:				
Basic	N/A	$ 0.58	N/A	$ 1.24
Diluted	N/A	$ 0.58	N/A	$ 1.24
Dividends paid per share of common stock	N/A	$ 0.3325	N/A	$ 0.9975

See Notes to Condensed Consolidated Financial Statements.
These interim statements are unaudited.

DPL INC.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME / (LOSS)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	**2012**	2011
$ in millions	**Successor**	Predecessor	**Successor**	Predecessor
Net income / (loss)	**$ (1,810.9)**	$ 67.1	**$ (1,777.3)**	$ 142.3
Available-for-sale securities activity:				
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $(0.1) and $0.2, respectively, for the three month period and $(0.3) and $0.2, respectively for the nine month period	**0.2**	(0.3)	**0.5**	(0.3)
Total change in fair value of available-for-sale securities	**0.2**	(0.3)	**0.5**	(0.3)
Derivative activity:				
Change in derivative fair value net of income tax benefit / (expense) of $(0.3) and $25.9, respectively, for the three month period and $3.4 and $30.2, respectively, for the nine month period	**0.3**	(48.1)	**(5.5)**	(59.5)
Reclassification of earnings, net of income tax benefit / (expense) of $0.0 and $(1.0), respectively, for the three month period and $0.7 and $(1.3), respectively, for the nine month period	**-**	1.5	**(0.8)**	4.1
Total change in fair value of derivatives	**0.3**	(46.6)	**(6.3)**	(55.4)
Pension and postretirement activity:				
Reclassification to earnings, net of income tax benefit / (expense) of $0.0 and $0.1, respectively, for the three month period and $0.0 and $0.7, respectively, for the nine month period	**-**	0.9	**(0.1)**	2.5
Total change in unfunded pension obligation	**-**	0.9	**(0.1)**	2.5
Other comprehensive income / (loss)	**0.5**	(46.0)	**(5.9)**	(53.2)
Net comprehensive income / (loss)	**$ (1,810.4)**	$ 21.1	**$ (1,783.2)**	$ 89.1

See Notes to Condensed Consolidated Financial Statements.
These interim statements are unaudited.

DPL INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Nine Months Ended

$ in millions	September 30, 2012 Successor	2011 Predecessor
Cash flows from operating activities:		
Net income / (loss)	$ (1,777.3)	$ 142.3
Adjustments to reconcile Net income to Net cash provided by operating activities:		
Depreciation and amortization	95.6	106.0
Amortization of intangibles	71.2	-
Amortization of debt market value adjustments	(14.2)	-
Deferred income taxes	(10.5)	70.5
Charge for early redemption of debt	-	15.3
Goodwill impairment	1,850.0	-
Recognition of deferred SECA revenue	(17.8)	-
Changes in certain assets and liabilities:		
Accounts receivable	(10.2)	21.1
Inventories	29.5	(9.1)
Prepaid taxes	0.6	(27.0)
Taxes applicable to subsequent years	59.9	47.7
Deferred regulatory costs, net	2.7	7.9
Accounts payable	(16.7)	(13.4)
Accrued taxes payable	(49.4)	(58.2)
Accrued interest payable	25.2	(3.1)
Pension, retiree and other benefits	24.4	(31.7)
Unamortized investment tax credit	(0.2)	(2.1)
Insurance and claims costs	(1.3)	4.1
Other	(11.8)	3.6
Net cash provided by operating activities	249.7	273.9
Cash flows from investing activities:		
Capital expenditures	(163.1)	(141.3)
Purchase of MC Squared	-	(8.3)
Increase in restricted cash	(0.4)	(9.1)
Purchases of short-term investments and securities	-	(1.7)
Sales of short-term investments and securities	-	70.9
Other	-	1.5
Net cash from investing activities	(163.5)	(88.0)

DPL INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (cont.)

$ in millions	Nine Months Ended September 30, 2012 Successor	2011 Predecessor
Net cash from financing activities:		
Dividends paid on common stock	(45.0)	(113.8)
Contributions to additional paid-in capital from parent	0.3	-
Payment to former warrant holders	(9.0)	-
Deferred finance costs	(0.3)	-
Issuance of long-term debt	-	300.0
Retirement of long-term debt	(0.1)	(297.4)
Early redemption of Capital Trust II debt	-	(122.0)
Premium paid for early redemption of debt	-	(12.2)
Payment of MC Squared debt	-	(13.5)
Withdrawals from revolving credit facilities	-	50.0

Repayment of borrowing from revolving credit facilities		-		(50.0)
Exercise of stock options		-		1.6
Exercise of warrants		-		14.7
Tax impact related to exercise of stock options		-		0.3
Net cash from financing activities		**(54.1)**		(242.3)
Cash and cash equivalents:				
Net change		**32.1**		(56.4)
Balance at beginning of period		**173.5**		124.0
Cash and cash equivalents at end of period	**$**	**205.6**	$	67.6
Supplemental cash flow information:				
Interest paid, net of amounts capitalized	**$**	**78.1**	$	49.4
Income taxes paid, net	**$**	**43.0**	$	25.5
Non-cash financing and investing activities:				
Accruals for capital expenditures	**$**	**12.5**	$	14.8
Long-term liability incurred for purchase of plant assets	**$**	**-**	$	18.7

See Notes to Condensed Consolidated Financial Statements.
These interim statements are unaudited.

DPL INC.
CONDENSED CONSOLIDATED BALANCE SHEETS

$ in millions		**At September 30, 2012**		At December 31, 2011
		Successor		
ASSETS				
Current assets:				
Cash and cash equivalents	**$**	**205.6**	$	173.5
Restricted cash		**22.6**		22.2
Accounts receivable, net (Note 3)		**233.0**		219.1
Inventories (Note 3)		**96.3**		125.8
Taxes applicable to subsequent years		**16.6**		76.5
Regulatory assets, current (Note 4)		**21.8**		20.8
Other prepayments and current assets		**26.4**		30.4
Total current assets		**622.3**		668.3
Property, plant & equipment:				
Property, plant & equipment		**2,629.1**		2,360.3
Less: Accumulated depreciation and amortization		**(173.8)**		(7.5)
		2,455.3		2,352.8
Construction work in process		**100.1**		152.3
Total net property, plant & equipment		**2,555.4**		2,505.1
Other noncurrent assets:				
Regulatory assets, non-current (Note 4)		**181.3**		193.2
Goodwill		**726.3**		2,576.3
Intangible assets, net of amortization		**75.0**		142.4
Other deferred assets		**33.9**		51.9
Total other noncurrent assets		**1,016.5**		2,963.8
Total assets	**$**	**4,194.2**	$	6,137.2

See Notes to Condensed Consolidated Financial Statements.
These interim statements are unaudited.

DPL INC.
CONDENSED CONSOLIDATED BALANCE SHEETS

At At

$ in millions	September 30, 2012	December 31, 2011
	Successor	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 6)	$ **0.4**	$ 0.4
Accounts payable	**78.6**	111.1
Accrued taxes	**88.9**	63.2
Accrued interest	**55.7**	30.2
Customer security deposits	**15.9**	15.9
Regulatory liabilities, current (Note 4)	**-**	0.5
Dividends payable	**25.0**	-
Insurance and claims costs	**12.9**	14.2
Other current liabilities	**68.9**	68.4
Total current liabilities	**346.3**	303.9
Noncurrent liabilities:		
Long-term debt (Note 6)	**2,614.5**	2,628.9
Deferred taxes (Note 7)	**523.3**	542.4
Taxes payable	**24.5**	96.9
Regulatory liabilities, non-current (Note4)	**117.5**	118.6
Pension, retiree and other benefits	**55.7**	47.5
Derivative liability	**41.1**	46.1
Unamortized investment tax credit	**3.4**	3.6
Other deferred credits	**73.3**	100.2
Total noncurrent liabilities	**3,453.3**	3,584.2
Redeemable preferred stock of subsidiary	**18.4**	18.4
Commitments and contingencies (Note 13)		
Common shareholder's equity:		
Common stock:		
1,500 shares authorized; 1 share issued and outstanding at September 30, 2012 and December 31, 2011		
Other paid-in capital	**2,235.9**	2,237.3
Accumulated other comprehensive loss	**(6.3)**	(0.4)
Retained deficit	**(1,853.4)**	(6.2)
Total common shareholder's equity	**376.2**	2,230.7
Total liabilities and shareholder's equity	$ **4,194.2**	$ 6,137.2

See Notes to Condensed Consolidated Financial Statements.
These interim statements are unaudited.

Notes to Condensed Consolidated Financial Statements (Unaudited)

1. Overview and Summary of Significant Accounting Policies

Description of Business

DPL is a diversified regional energy company organized in 1985 under the laws of Ohio. **DPL's** two reportable segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER operations, which include the operations of DPLER's wholly owned subsidiary MC Squared. Refer to Note 14 for more information relating to these reportable segments.

On November 28, 2011, **DPL** was acquired by AES in the Merger and **DPL** became a wholly owned subsidiary of AES. See Note 2.

DP&L is a public utility incorporated in 1911 under the laws of Ohio. **DP&L** is engaged in the generation, transmission, distribution and sale of electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. Electricity for **DP&L's** 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense.

DP&L's sales reflect the general economic conditions and seasonal weather patterns of the area. **DP&L** sells any excess energy and capacity into the wholesale market.

DPLER sells competitive retail electric service, under contract, to residential, commercial and industrial customers. DPLER's operations include those of its wholly owned subsidiary, MC Squared, which was acquired on February 28, 2011. DPLER has approximately 175,000 customers currently located throughout Ohio and Illinois. DPLER does not own any transmission or generation assets, and all of DPLER's electric energy was purchased from **DP&L** or PJM to meet its sales obligations. DPLER's sales reflect the general economic conditions and seasonal weather patterns of the areas it serves.

DPL's other significant subsidiaries include DPLE, which owns and operates peaking generating facilities from which it makes wholesale sales of electricity and MVIC, our captive insurance company that provides insurance services to us and our subsidiaries. All of **DPL's** subsidiaries are wholly owned.

DPL also has a wholly owned business trust, DPL Capital Trust II, formed for the purpose of issuing trust capital securities to investors.

DP&L's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law. Accordingly, **DP&L** applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates, and regulatory liabilities when current cost recoveries in customer rates relate to expected future costs.

DPL and its subsidiaries employed 1,501 people as of September 30, 2012, of which 1,443 employees were employed by **DP&L**. Approximately 52% of all employees are under a collective bargaining agreement which expires on October 31, 2014.

Financial Statement Presentation

DPL's Condensed Consolidated Financial Statements include the accounts of **DPL** and its wholly owned subsidiaries except for DPL Capital Trust II which is not consolidated, consistent with the provisions of GAAP. **DP&L's** undivided ownership interests in certain coal-fired generating plants are included in the financial statements at amortized cost, which was adjusted to fair value at the Merger date for **DPL Inc**. Operating revenues and expenses of these generating plants are included on a pro rata basis in the corresponding lines in the Condensed Consolidated Statement of Operations. See Note 5 for more information.

Certain excise taxes collected from customers have been reclassified out of operating expenses in the 2011 presentation to conform to AES' presentation of these items. These taxes are presented net within revenue. Certain immaterial amounts from prior periods have been reclassified to conform to the current reporting presentation.

All material intercompany accounts and transactions are eliminated in consolidation.

These financial statements have been prepared in accordance with GAAP for interim financial statements, the instructions of Form 10-Q and Regulation S-X. Accordingly, certain information and footnote disclosures normally included in the annual financial statements prepared in accordance with GAAP have been omitted from this interim report. Therefore, our interim financial statements in this report should be read along with the annual financial statements included in our Form 10-K for the fiscal year ended December 31, 2011.

In the opinion of our management, the Condensed Consolidated Financial Statements presented in this report contain all adjustments necessary to fairly state our financial condition as of September 30, 2012; our results of operations for the three and nine months ended September 30, 2012 and our cash flows for the nine months ended September 30, 2012 and 2011. Unless otherwise noted, all adjustments are normal and recurring in nature. Due to various factors, including but not limited to, seasonal weather variations, the timing of outages of electric generating units, changes in economic conditions involving commodity prices and competition, and other factors, interim results for the three and nine months ended September 30, 2012 may not be indicative of our results that will be realized for the full year ending December 31, 2012.

The preparation of financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the revenues and expenses of the periods reported. Actual results could differ from these estimates. Significant items subject to such estimates and judgments include: the carrying value of property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; assets and liabilities related to employee benefits; goodwill; and intangibles.

On November 28, 2011, AES completed the Merger with **DPL**. As a result of the Merger, **DPL** is an indirectly wholly owned subsidiary of AES. **DPL's** basis of accounting incorporates the application of FASC 805, "Business Combinations" (FASC 805) as of the date of the Merger. FASC 805 requires the acquirer to recognize and measure identifiable assets acquired and liabilities assumed at fair value as of the Merger date. **DPL's** Condensed Consolidated Financial Statements and accompanying footnotes have been segregated to present pre-merger activity as the "Predecessor" Company and post-merger activity as the "Successor" Company. Purchase accounting impacts, including goodwill recognition, have been "pushed down" to **DPL**, resulting in the assets and liabilities of **DPL** being recorded at their respective fair values as of November 28, 2011. The purchase price allocation was finalized in the third quarter of 2012.

As a result of the push down accounting, **DPL's** Condensed Consolidated Statements of Operations subsequent to the Merger include amortization expense relating to purchase accounting adjustments and depreciation of fixed assets based upon their fair value. Therefore, the **DPL** financial data prior to the Merger will not generally be comparable to its financial data subsequent to the Merger.

In connection with the Merger, **DPL** remeasured the carrying amount of all of its assets and liabilities to fair value, which resulted in the recognition of approximately $2,576.3 million of goodwill (see Note 2), assigned to **DPL's** two reporting units, DPLER and the **DP&L** Reporting Unit, which includes **DP&L** and other entities. FASC 350, "Intangibles – Goodwill and Other," requires that goodwill be tested for impairment at the reporting unit level at least annually or more frequently if impairment indicators are present. In evaluating the potential impairment of goodwill, we make estimates and assumptions about revenue, operating cash flows, capital expenditures, growth rates and discount rates based on our budgets and long term forecasts, macroeconomic projections, and current market expectations of returns on similar assets. There are inherent uncertainties related to these factors and management's judgment in applying these factors. Generally, the fair value of a reporting unit is determined using a discounted cash flow valuation model. We could be required to evaluate the potential impairment of goodwill outside of the required annual assessment process if we experience situations, including but not limited to: deterioration in general economic conditions; changes to our operating or regulatory environment; increased competitive environment; increase in fuel costs particularly when we are unable to pass its effect to customers; negative or declining cash flows; loss of a key contract or customer, particularly when we are unable to replace it on equally favorable terms; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. In the third quarter of 2012, we recorded an impairment charge of $1,850.0 million against the goodwill at **DPL's DP&L** Reporting Unit. See Note 15 for more information.

As part of the purchase accounting, values were assigned to various intangible assets, including customer relationships, customer contracts and the value of our ESP.

Sale of Receivables

In the first quarter of 2012, DPLER began selling receivables from DPLER customers in Duke Energy's territory to Duke Energy. These sales are at face value for cash at the billed amounts for DPLER customers' use of energy. There is no recourse or any other continuing involvement associated with the sold receivables. Total receivables sold during the three and nine months ended September 30, 2012 were $6.1 million and $11.3 million, respectively.

Property, Plant and Equipment

We record our ownership share of our undivided interest in jointly-held plants as an asset in property, plant and equipment. Property, plant and equipment are stated at cost. For regulated transmission and distribution property, cost includes direct labor and material, allocable overhead expenses and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of borrowed funds and equity used to finance regulated construction projects. For non-regulated property, cost also includes capitalized interest. Capitalization of AFUDC and interest ceases at either project completion or at the date specified by regulators. AFUDC and capitalized interest was $0.9 million and $1.1 million during the three months and $3.4 million and $3.5 million during the nine months ended September 30, 2012 and 2011, respectively.

For unregulated generation property, cost includes direct labor and material, allocable overhead expenses and interest capitalized during construction using the provisions of GAAP relating to the accounting for capitalized interest.

For substantially all depreciable property, when a unit of property is retired, the original cost of that property less any salvage value is charged to Accumulated depreciation and amortization.

Property is evaluated for impairment when events or changes in circumstances indicate that its carrying amount may not be recoverable.

Intangibles

Intangibles include emission allowances, renewable energy credits, customer relationships, customer contracts and the value of our ESP. Emission allowances are carried on a first-in, first-out (FIFO) basis for purchased emission allowances. In addition, we recorded emission allowances at their fair value as of the Merger date. Net gains or losses on the sale of excess emission allowances, representing the difference between the sales proceeds and the cost of emission allowances, are recorded as a component of our fuel costs and are reflected in Operating income when realized. During the nine months ended September 30, 2012 and 2011, **DPL** had no gains from the sale of emission allowances. Beginning in January 2010, part of the gains on emission allowances were used to reduce the overall fuel rider charged to our SSO retail customers.

Customer relationships recognized as part of the purchase accounting associated with the Merger are amortized over ten to seventeen years and customer contracts are amortized over the average length of the contracts. The ESP is amortized over one year on a straight-line basis. Emission allowances are amortized as they are used in our operations on a FIFO basis. Renewable energy credits are amortized as they are used or retired.

Prior to the Merger date, emission allowances and renewable energy credits were carried as inventory. Emission allowances and renewable energy credits are now carried as intangibles in accordance with AES' policy. The amounts for 2011 have been reclassified to reflect this change in presentation.

Accounting for Taxes Collected from Customers and Remitted to Governmental Authorities

DPL collects certain excise taxes levied by state or local governments from its customers. Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, these taxes are accounted for on a net basis and recorded as a reduction in revenues for presentation in accordance with AES policy. The amounts for the three months ended September 30, 2012 and 2011 were $13.8 million and $14.3 million, respectively. The amounts for the nine months ended September 30, 2012 and 2011 were $38.5 million and $39.9 million, respectively. The 2011 amounts were reclassified to conform to this presentation.

Share-Based Compensation

We measure the cost of employee services received and paid with equity instruments based on the fair-value of such equity instrument on the grant date. This cost is recognized in results of operations over the period that employees are required to provide service. Liability awards are initially recorded based on the fair-value of equity instruments and are to be re-measured for the change in stock price at each subsequent reporting date until the liability is ultimately settled. The fair-value for employee share options and other similar instruments at the grant date are estimated using option-pricing models and any excess tax benefits are recognized as an addition to paid-in capital. The reduction in income taxes payable from the excess tax benefits is presented in the Condensed Consolidated Statements of Cash Flows within Cash flows from financing activities. As a result of the Merger (see Note 2), vesting of all DPL share-based awards was accelerated as of the Merger date, and none are in existence at September 30, 2012.

Recently Issued Accounting Standards

Offsetting Assets and Liabilities

In December 2011, the FASB issued ASU 2011-11 "Disclosures about Offsetting Assets and Liabilities" (ASU 2011-11) effective for interim and annual reporting periods beginning on or after January 1, 2013. We expect to adopt this ASU on January 1, 2013. This standard updates FASC Topic 210, "Balance Sheet." ASU 2011-11 updates the disclosures for financial instruments and derivatives to provide more transparent information around the offsetting of assets and liabilities. Entities are required to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and/or subject to an agreement similar to a master netting agreement. We do not expect these new rules to have a material impact on our overall results of operations, financial position or cash flows.

Testing Indefinite-Lived Intangible Assets for Impairments

In July 2012, the FASB issued ASU 2012-02 "Testing Indefinite-Lived Intangible Assets for Impairment" (ASU 2012-02) effective for interim and annual impairment tests performed for fiscal years beginning after September 15, 2012. We expect to adopt this ASU on January 1, 2013. This standard updates FASC Topic 350, "Intangibles-Goodwill and Other." ASU 2012-02 permits an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired as a basis for determining whether it is necessary to perform the quantitative impairment test in accordance with FASC Subtopic 350-30. After adoption, we do not expect these new rules to have a material impact on our overall results of operations, financial position or cash flows.

Recently Adopted Accounting Standards

Fair Value Disclosures

In May 2011, the FASB issued ASU 2011-04 "Fair Value Measurements" (ASU 2011-04) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 820, "Fair Value Measurements." ASU 2011-04 essentially converges US GAAP guidance on fair value with the IFRS guidance. The ASU requires more disclosures around Level 3 inputs. It also increases reporting for financial instruments disclosed at fair value but not recorded at fair value and provides clarification of blockage factors and other premiums and discounts. These new rules did not have a material effect on our overall results of operations, financial position or cash flows.

Comprehensive Income

In June 2011, the FASB issued ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 220, "Comprehensive Income." ASU 2011-05 essentially converges US GAAP guidance on the presentation of comprehensive income with the IFRS guidance. The ASU requires the presentation of comprehensive income in one continuous financial statement or two separate but consecutive statements. Any reclassification adjustments from other comprehensive income to net income are required to be presented on the face of the Statement of Comprehensive Income. These new rules did not have a material effect on our overall results of operations, financial position or cash flows.

Goodwill Impairment

In September 2011, the FASB issued ASU 2011-08 "Testing Goodwill for Impairment" (ASU 2011-08) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 350, "Intangibles-Goodwill and Other." ASU 2011-08 allows an entity to first test Goodwill using qualitative factors to determine if it is more likely than not that the fair value of a

reporting unit has been impaired; if so, then the two-step impairment test is performed. We will incorporate these new requirements in our future goodwill impairment testing.

Derivative gross vs. net presentation – Following the acquisition of DPL in November 2011 by AES, DPL began presenting its derivative positions on a gross basis in accordance with AES policy. This change has been reflected in the 2011 balance sheet contained in these statements.

2. Business Combination

On November 28, 2011, AES completed its acquisition of **DPL**. AES paid cash consideration of approximately $3,483.6 million. The allocation of the purchase price was based on the estimated fair value of assets acquired and liabilities assumed. In addition, Dolphin Subsidiary II, Inc. (a wholly owned subsidiary of AES) issued $1,250.0 million of debt, which, as a result of the merger of **DPL** and Dolphin Subsidiary II, Inc. was assumed by **DPL**. The assets acquired and liabilities assumed in the acquisition were recorded at estimated amounts based on the purchase price allocation. We finalized the allocation of the purchase price in the third quarter of 2012.

From November 28, 2011 through September 30, 2012, we recognized the following changes to our preliminary purchase price allocation:

	Decrease / (increase) to preliminary goodwill	
$ in millions	Change before deferred income tax effect	Deferred income tax effect
Property, plant and equipment (1)	$ (70.7)	$ 25.5
DPLER intangibles (2)	(19.1)	6.7
Out of market coal contract (3)	(34.2)	12.0
Deferred tax liabilities (4)	-	(20.7)
Regulatory assets (5)	15.4	-
Taxes payable (6)	13.1	(16.0)
Other	1.0	-
	$ (94.5)	$ 7.5

Net (increase) in goodwill	$ (87.0)

(1) related to refined information associated with certain contractual arrangements, growth and ancillary revenue assumptions.
(2) related to refined market and contractual information.
(3) related to a change in certain assumptions related to an out of market coal contract.
(4) related to an assessment of our overall deferred tax liabilities on regulated property, plant and equipment.
(5) related to the increase in deferred taxes discussed in *(4)* above.
(6) related to the final DPL Inc. standalone federal tax return.

These purchase price adjustments increased the provisionally recognized goodwill by $87.0 million and have been reflected retrospectively as of December 31, 2011 in the accompanying Condensed Consolidated Balance Sheets. The effect on net income for the nine months ended September 30, 2012 of $8.7 million was recorded in the second and third quarters. The effect on net income for the period November 28, 2011 through December 31, 2011 was not material.

Estimated preliminary and final fair value of assets acquired and liabilities assumed as of the Merger date are as follows:

$ in millions	Final purchase price allocation	Preliminary purchase price allocation
Cash	$ 116.4	$ 116.4
Restricted cash	18.5	18.5
Accounts receivable	277.6	277.6
Inventory	123.7	123.7
Other current assets	37.3	37.3
Property, plant and equipment	2,477.8	2,548.5
Intangible assets subject to amortization	147.2	166.3
Intangible assets - indefinite-lived	5.0	5.0
Regulatory assets	217.1	201.1
Other non-current assets	58.3	58.3
Current liabilities	(413.1)	(408.2)
Debt	(1,255.1)	(1,255.1)
Deferred taxes	(551.2)	(558.2)
Regulatory liabilities	(117.0)	(117.0)
Other non-current liabilities	(216.8)	(201.5)
Redeemable preferred stock	(18.4)	(18.4)
Net identifiable assets acquired	907.3	994.3
Goodwill	2,576.3	2,489.3
Net assets acquired	$ 3,483.6	$ 3,483.6

3. Supplemental Financial Information

$ in millions	At September 30, 2012	At December 31, 2011
	Successor	
Accounts receivable, net:		
Unbilled revenue	$ **62.0**	$ 72.4
Customer receivables	**131.8**	113.2
Amounts due from partners in jointly-owned plants	**16.5**	29.2
Coal sales	**4.5**	1.0
Other	**19.4**	4.4
Provision for uncollectible accounts	**(1.2)**	(1.1)
Total accounts receivable, net	$ **233.0**	$ 219.1

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Inventories, at average cost:		
Fuel, limestone and emission allowances	$ **53.6**	$ 84.2
Plant materials and supplies	**40.7**	39.8
Other	**2.0**	1.8
Total inventories, at average cost	$ **96.3**	$ 125.8

Accumulated Other Comprehensive Income / (Loss)

AOCI is included on our balance sheets within the Common shareholders' equity sections. The following table provides the components that constitute the balance sheet amounts in AOCI at September 30, 2012 and December 31, 2011 :

$ in millions	At September 30, 2012	At December 31, 2011
	Successor	
Financial Instruments	$ **0.5**	$ -
Cash flow hedges	**(6.8)**	(0.5)
Pension and postretirement benefits	**-**	0.1
Total	$ **(6.3)**	$ (0.4)

4. Regulatory Assets and Liabilities

In accordance with GAAP, regulatory assets and liabilities are recorded in the Condensed Consolidated Balance Sheets for our regulated electric transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and regulatory liabilities represent current recovery of expected future costs or gains probable of being reflected in future rates.

We evaluate our regulatory assets each period and believe that recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator.

Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected.

The following table presents **DPL's** regulatory assets and liabilities:

$ in millions	Type of Recovery (a)	Amortization through	At September 30, 2012	At December 31, 2011
			Successor	
Current regulatory assets:				
TCRR, transmission, ancillary and other PJM-related costs	F	Ongoing	$ **6.3**	$ 4.7
Power plant emission fees	C	Ongoing	**(0.3)**	4.8
Fuel and purchased power recovery costs	C	Ongoing	**15.8**	11.3
Total regulatory assets - current			$ **21.8**	$ 20.8
Non-current regulatory assets:				
Deferred recoverable income taxes	B/C	Ongoing	$ **37.0**	$ 39.5
Pension benefits	C	Ongoing	**87.1**	92.1
Unamortized loss on reacquired debt	C	Ongoing	**12.2**	13.0
Regional transmission organization costs	D	2014	**3.0**	4.1
Deferred storm costs - 2008	D		**18.7**	17.9
CCEM smart grid and advanced metering infrastructure costs	D		**6.6**	6.6
CCEM energy efficiency program costs	F	Ongoing	**5.9**	8.8
Consumer education campaign	D		**3.0**	3.0

Retail settlement system costs	D	3.1	3.1
Other costs		4.7	5.1
Total regulatory assets - non-current		$ 181.3	$ 193.2
Current regulatory liabilities:			
Other		$ -	$ 0.5
Total regulatory liabilities - current		$ -	$ 0.5
Non-current regulatory liabilities:			
Estimated costs of removal - regulated property		$ 111.6	$ 112.4
Postretirement benefits		5.6	6.2
Other		0.3	-
Total regulatory liabilities - non-current		$ 117.5	$ 118.6

(a) *B – Balance has an offsetting liability resulting in no effect on rate base.*
C – Recovery of incurred costs without a rate of return.
D – Recovery not yet determined, but is probable of occurring in future rate proceedings.
F – Recovery of incurred costs plus rate of return.

Regulatory Assets

TCRR, transmission, ancillary and other PJM-related costs represent the costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. On an annual basis, retail rates are adjusted to true-up costs with recovery in rates.

Power plant emission fees represent costs paid to the State of Ohio since 2002. As part of the fuel factor settlement agreement in November 2011, these costs are being recovered through the fuel factor.

Fuel and purchased power recovery costs represent prudently incurred fuel, purchased power, derivative, emission and other related costs which will be recovered from or returned to customers in the future through the operation of the fuel and purchased power recovery rider. The fuel and purchased power recovery rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter. **DP&L** implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. We received the audit report for 2011 on April 27, 2012. The auditor has recommended that the PUCO consider reducing **DP&L's** recovery of fuel costs by approximately $3.3 million from certain transactions. On October 4, 2012, we filed testimony on this issue and a hearing is scheduled in November 2012 before a hearing examiner. A decision is expected in the fourth quarter of 2012. As of September 30, 2012, we believe the entire amount is recoverable.

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow through items as the result of tax benefits previously provided to customers. This is the cumulative flow through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes will decrease over time.

Pension benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" costs of our regulated operations that for ratemaking purposes are deferred for future recovery. We 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 (OCI), 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. This regulatory asset represents the regulated portion that would otherwise be charged as a loss to OCI.

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed in prior periods. These costs are being amortized over the lives of the original issues in accordance with FERC and PUCO rules.

Regional transmission organization costs represent costs incurred to join an RTO. The recovery of these costs will be requested in a future FERC rate case. In accordance with FERC precedence, we are amortizing these costs over a 10-year period that began in 2004 when we joined the PJM RTO.

Deferred storm costs – 2008 relate to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other major 2008 storms. On January 14, 2009, the PUCO granted **DP&L** the authority to defer these costs with a return until such time that **DP&L** seeks recovery in a future rate proceeding.

CCEM smart grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and implementation of AMI. On October 19, 2010, **DP&L** elected to withdraw its case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects **DP&L** to continue to monitor other utilities' Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that **DP&L** will, when appropriate, file new Smart Grid and/or AMI business cases in the future. We plan to file to recover these deferred costs in a future regulatory rate proceeding. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

CCEM energy efficiency program costs represent costs incurred to develop and implement various new customer programs addressing energy efficiency. These costs are being recovered through an energy efficiency rider (EER) that began July 1, 2009 and is subject to a two-year true-up for any over/under recovery of costs. On April 29, 2011, **DP&L** filed to true-up the EER which was approved by the PUCO on October 18, 2011. **DP&L** plans to make its next true-up filing on or before April 30, 2013.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation. **DP&L** will be seeking recovery of these costs as part of our next distribution rate case filing at the PUCO. The timing of such a filing has not yet been determined.

Retail settlement system costs represent costs to implement a retail settlement system that reconciles the energy a CRES supplier delivers to its customers and what its customers actually use. Based on case precedent in other utilities' cases, the costs are recoverable through a future **DP&L** rate proceeding.

Other costs primarily include RPM capacity, other PJM and rate case costs and alternative energy costs that are or will be recovered over various periods.

Regulatory Liabilities

Estimated costs of removal – regulated property reflect an estimate of amounts collected in customer rates for costs that are expected to be incurred in the future to remove existing transmission and distribution property from service when the property is retired.

Postretirement benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" gains related to our regulated operations that, for ratemaking purposes, are probable of being reflected in future rates. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, 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. This regulatory liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

Pending Regulatory Activity

On August 10, 2012, **DP&L** filed with the PUCO for an accounting order for permission to defer operation and maintenance costs as a result of damage caused by storms occurring during the final weekend of June 2012. The deferral request is for distribution expense incurred for these storms. The deferral would earn a return equal to the carrying cost of debt (5.86%) until these costs are recovered from customers. On October 19, 2012, DP&L amended its filing to change the method of calculating the deferral. If PUCO approval is received, **DP&L** will defer approximately $5.8 million of costs associated with these storms.

5. Ownership of Coal-fired Facilities

DP&L has undivided ownership interests in seven coal-fired electric generating facilities and numerous transmission facilities with certain other Ohio utilities. Certain expenses, primarily fuel costs for the generating stations, are allocated to the owners based on their energy usage. The remaining expenses, investments in fuel inventory, plant materials and operating supplies, and capital additions are allocated to the owners in accordance with their respective ownership interests. As of September 30, 2012, **DP&L** had $31.0 million of construction work in process at such jointly-owned facilities. **DP&L's** share of the operating cost of such facilities is included within the corresponding line in the Condensed Consolidated Statements of Results of Operations and **DP&L's** share of the investment in the facilities is included within Total net property, plant and equipment in the Condensed Consolidated Balance Sheets. Each joint owner provides their own financing for their share of the operations and capital expenditures of the jointly owned station.

DP&L's undivided ownership interest in such facilities as well as our wholly owned coal-fired Hutchings station at September 30, 2012 is as follows:

	DP&L Share		DP&L Investment (adjusted to fair value at Merger date)			
Jointly-owned production stations:	Ownership (%)	Summer Production Capacity (MW)	Gross Plant in Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)	SCR and FGD Equipment Installed and in Service (Yes/No)
Beckjord Unit 6	50.0	207	$ 1	$ 1	$ -	No
Conesville Unit 4	16.5	129	42	4	8	Yes
East Bend Station	31.0	186	11	6	1	Yes
Killen Station	67.0	402	316	15	4	Yes
Miami Fort Units 7 and 8	36.0	368	217	9	3	Yes
Stuart Station	35.0	808	206	16	12	Yes
Zimmer Station	28.1	365	182	27	3	Yes
Transmission (at varying percentages)		n/a	35	2	-	
Total		2,465	$ 1,010	$ 80	$ 31	
Wholly-owned production station:						
Hutchings Station	100.0	365	$ -	$ -	$ -	No

Currently, our coal-fired generation units at Hutchings and Beckjord do not have SCR and FGD emission-control equipment installed. **DP&L** owns 100% of the Hutchings station and has a 50% interest in Beckjord Unit 6. On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord station, including our jointly owned Unit 6, in December 2014. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. **DP&L** does not object to Duke's decision. Beckjord Unit 6 was valued at zero at the Merger date.

We are considering options for the Hutchings station, but have not yet made a final decision. **DP&L** has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated and unavailable for service until at least June 1, 2014, if not indeterminately. In addition, **DP&L** has notified PJM that Hutchings Units 1 and 2 will be deactivated by June 1, 2015. The decision to deactivate Units 1 and 2 has been made because these two units are not equipped with the advanced environmental control technologies needed to comply with the MACT standard, which was renamed MATS (Mercury Air Toxics Standard) when the rule was issued final on December 16, 2011, and the cost of compliance with the MATS standard or conversion to natural gas for these units would likely exceed the expected return. **DP&L** is still studying the option of converting two or more of Hutchings Units 3-6 to natural gas in order to comply with environmental requirements.

DPL revalued **DP&L's** investment in the above plants at the estimated fair value for each plant at the Merger date.

6. Debt Obligations

All debt outstanding at the Merger date was revalued at the estimated fair value.

Long-term debt

$ in millions	**At September 30, 2012**	At December 31, 2011
First mortgage bonds maturing in October 2013 - 5.125%	$ **489.4**	$ 503.6
Pollution control series maturing in January 2028 - 4.70%	**36.1**	36.1
Pollution control series maturing in January 2034 - 4.80%	**179.6**	179.6
Pollution control series maturing in September 2036 - 4.80%	**96.2**	96.2
Pollution control series maturing in November 2040		

- variable rates: 0.04% - 0.26% and 0.06% - 0.32% (a)		**100.0**		100.0
U.S. Government note maturing in February 2061 - 4.20%		**18.4**		18.5
Capital lease obligation		**0.2**		0.4
Total long-term debt at subsidiary		**919.9**		934.4
Bank Term Loan				
- variable rates: 2.22% - 2.30% and 1.48% - 4.25% (b)		**425.0**		425.0
Senior unsecured bonds maturing October 2016 - 6.50%		**450.0**		450.0
Senior unsecured bonds maturing October 2021 - 7.25%		**800.0**		800.0
Note to DPL Capital Trust II maturing in September 2031 - 8.125%		**19.6**		19.5
Total long-term debt	$	**2,614.5**	$	2,628.9

Current portion - long-term debt

$ in millions		**At September 30, 2012**		At December 31, 2011
U.S. Government note maturing in February 2061 - 4.20%	$	**0.1**	$	0.1
Capital lease obligation		**0.3**		0.3
Total current portion - long-term debt - DPL	$	**0.4**	$	**0.4**

(a) Range of interest rates for the nine months ended September 30, 2012 and the twelve months ended December 31, 2011, respectively.

(b) Range of interest rates for the nine months ended September 30, 2012 and from the draw-down of the loan in August 2011 through December 31, 2011, respectively.

At September 30, 2012, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions		
Due within one year	$	0.4
Due within two years		895.3
Due within three years		0.1
Due within four years		0.1
Due within five years		450.1
Thereafter		1,252.9
Total maturities		2,598.9
Unamortized adjustments to market value from purchase accounting		16.0
Total long-term debt	$	2,614.9

Premiums or discounts recognized at the Merger date are amortized over the life of the debt using the effective interest method.

On December 4, 2008, the OAQDA issued $100.0 million of collateralized, variable rate Revenue Refunding Bonds Series A and B due November 1, 2040. In turn, **DP&L** borrowed these funds from the OAQDA and issued corresponding First Mortgage Bonds to support repayment of the funds. The payment of principal and interest on each series of the bonds when due is backed by a standby letter of credit issued by JPMorgan Chase Bank, N.A. This letter of credit facility, which expires in December 2013, is irrevocable and has no subjective acceleration clauses. Fees associated with this letter of credit facility were not material during the three and nine months ended September 30, 2012 and 2011.

On April 20, 2010, **DP&L** entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on April 20, 2013 and provides **DP&L** with the ability to increase the size of the facility by an additional $50.0 million. **DP&L** had no outstanding borrowings under this credit facility at September 30, 2012 and December 31, 2011. Fees associated with this revolving credit facility were not material during the three and nine months ended September 30, 2012 and 2011. This facility also contains a $50.0 million letter of credit sublimit. As of September 30, 2012, **DP&L** had no outstanding letters of credit against this facility.

On February 23, 2011, **DPL** purchased $122.0 million principal amount of DPL Capital Trust II 8.125% capital securities in a privately negotiated transaction. As part of this transaction, **DPL** paid a premium of $12.2 million, or 10%. Debt issuance costs and unamortized debt discount totaling $3.1 million associated with this debt were expensed in February 2011 in conjunction with this transaction.

On March 1, 2011, **DP&L** completed the purchase of $18.7 million of electric transmission and distribution assets from the federal government that are located at the Wright-Patterson Air Force Base. **DP&L** financed the acquisition of these assets with a note payable to the federal government that is payable monthly over 50 years and bears interest at 4.2% per annum.

On August 24, 2011, **DP&L** entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a four year term expiring on August 24, 2015 and provides **DP&L** with the ability to increase the size of the facility by an additional $50.0 million. **DP&L** had no outstanding borrowings under this credit facility at September 30, 2012 and December 31, 2011. Fees associated with this revolving credit facility were not material during the three and nine months ended September 30, 2012 and 2011. This facility also contains a $50.0 million letter of credit sublimit. As of September 30, 2012, **DP&L** had no outstanding letters of credit against this facility.

On August 24, 2011, **DPL** entered into a $125.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on August 24, 2014. The size of the facility was reduced from $125.0 million to $75.0 million as part of an amendment dated October 19, 2012 that was negotiated between DPL and the syndicated bank group. **DPL** had no outstanding borrowings under this credit

facility at September 30, 2012 and December 31, 2011. Fees associated with this revolving credit facility were not material during the three and nine months ended September 30, 2012. This facility may also be used to issue letters of credit up to the $75.0 million limit. As of September 30, 2012, **DPL** had no outstanding letters of credit against this facility.

On August 24, 2011, **DPL** entered into a $425.0 million unsecured term loan agreement with a syndicated bank group. This agreement is for a three year term expiring on August 24, 2014. On October 19, 2012, **DPL** and the syndicated bank group approved an amendment, which reduced the size of the facility from $125.0 million to $75 million and modified certain covenants in the facility. **DPL** has borrowed the entire $425.0 million available under the facility at September 30, 2012. Fees associated with this term loan were not material during the three and nine months ended September 30, 2012.

DPL's unsecured revolving credit agreement and **DPL's** unsecured term loan each have two financial covenants, one of which was changed as part of amendments, dated October 19, 2012, to the facilities negotiated between **DPL** and the syndicated bank groups. The first financial covenant, originally a Total Debt to Capitalization ratio, was changed, effective September 30, 2012, to a Total Debt to EBITDA ratio. The Total Debt to EBITDA ratio is calculated, at the end of each fiscal quarter, by dividing total debt at the end of the current quarter by consolidated EBITDA for the four prior fiscal quarters.

The second financial covenant is an EBITDA to Interest Expense ratio. The EBITDA to Interest Expense ratio is calculated, at the end of each fiscal quarter, by dividing consolidated earnings before interest, taxes, depreciation and amortization (EBITDA) for the four prior fiscal quarters by the consolidated interest charges for the same period.

The amendments, dated October 19, 2012, to the facilities negotiated between **DPL** and the syndicated bank groups, restrict dividend payments from **DPL** to AES and adjust the cost of borrowing under the facilities.

In connection with the closing of the Merger (see Note 2), **DPL** assumed $1,250.0 million of debt that Dolphin Subsidiary II, Inc., a subsidiary of AES, issued on October 3, 2011 to partially finance the Merger. The $1,250.0 million was issued in two tranches. The first tranche was $450.0 million of five year senior unsecured notes issued with a 6.50% coupon maturing on October 15, 2016. The second tranche was $800.0 million of ten year senior unsecured notes issued with a 7.25% coupon maturing on October 15, 2021.

Substantially all property, plant and equipment of **DP&L** is subject to the lien of the mortgage securing **DP&L's** First and Refunding Mortgage, dated October 1, 1935, with the Bank of New York Mellon as Trustee.

7. Income Taxes

The following table details the effective tax rates for the three and nine months ended September 30, 2012 and 2011.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2012	**2011**	**2012**	**2011**
	Successor	Predecessor	**Successor**	Predecessor
DPL	**(1.2)%**	29.9%	**(2.3)%**	32.9%

Income tax expense for the three and nine months ended September 30, 2012 and 2011 was calculated using the estimated annual effective income tax rates of (2.2)% and 33.2% for 2012 and 2011, respectively. For the three and

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nine months ended September 30, 2011, management estimated the annual effective tax rate based upon its forecast of annual pre-tax income.

For the three and nine months ended September 30, 2012, management estimated the annual effective tax rate based upon actual pre-tax income for the period.

For the three months ended September 30, 2012, **DPL's** current period effective rate is greater than the estimated annual effective rate due to certain current period tax adjustments. These current period adjustments include a revision to the estimated annual effective rate resulting in a reduction in tax expense of $16.7 million as well as a reduction in tax expense of $0.9 million due to the effect of estimate-to-actual income tax provision adjustments related to non-deductible merger costs as well as non-deductible officers compensation.

For the nine months ended September 30, 2012, **DPL's** current period effective rate is less than the estimated annual effective rate due to certain current period tax adjustments. These current period adjustments include an increase in deferred state income tax expense of $3.6 million and an increase in other estimated tax liabilities of $0.2 million. These increases to tax expense are partially offset by a reduction in tax expense of $0.9 million due to the effect of estimate-to-actual income tax provision adjustments related to non-deductible merger costs as well as non-deductible officers compensation

For the three and nine months ended September 30, 2012, the decrease in **DPL's** effective tax rate compared to the same period in 2011 primarily reflects decreased pre-tax earnings related to the goodwill impairment during the third quarter of 2012.

Deferred tax liabilities for **DPL** decreased by approximately $25.4 million during the three months ended September 30, 2012 primarily related to purchase accounting adjustments and decreased $19.1 million during the nine months ended September 30, 2012 primarily related to purchase accounting adjustments, amortization and depreciation.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010 and has continued through the current quarter. At this time, we do not expect the results of this examination to have a material effect on our financial statements.

8. Pension and Postretirement Benefits

DP&L sponsors a defined benefit pension plan for the vast majority of its employees.

We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. There were no contributions made during the nine months ended September 30, 2012. **DP&L** made a discretionary contribution of $40.0 million to the defined benefit plan during the nine months ended September 30, 2011.

The amounts presented in the following tables for pension include both the collective bargaining plan formula, the traditional management plan formula, the cash balance plan formula and the SERP in the aggregate. The amounts presented for postretirement include both health and life insurance.

The net periodic benefit cost/(income) of the pension and postretirement benefit plans for the three months ended September 30, 2012 and 2011 was:

Net Periodic Benefit Cost / (Income)	**Pension**		**Postretirement**	
	Successor	Predecessor	**Successor**	Predecessor
$ in millions	**2012**	2011	**2012**	2011
Service cost	$ **1.5**	$ 0.8	$ **-**	$ -
Interest cost	**4.3**	4.1	**0.2**	0.2
Expected return on assets *(a)*	**(5.7)**	(6.2)	**(0.1)**	(0.1)
Amortization of unrecognized:				
Actuarial loss / (gain)	**1.3**	1.7	**(0.1)**	(0.5)
Prior service cost	**0.4**	0.5	**-**	0.1
Net periodic benefit cost / (income) before adjustments	**1.8**	0.9	**-**	(0.3)
Settlement cost *(b)*	**0.2**	-	**-**	-
Net periodic benefit cost / (income)	$ **2.0**	$ 0.9	$ **-**	$ (0.3)

(a) *For purposes of calculating the expected return on pension plan assets, under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be included in the MRVA equally over* *a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets for the 2012 and 2011 net periodic benefit cost was approximately $336.0 million and $316.0 million, respectively.*

(b) *The settlement cost relates to a former officer who has elected to receive a lump sum distribution in 2012 from the Supplemental Executive Retirement Plan.*

The net periodic benefit cost/(income) of the pension and postretirement benefit plans for the nine months ended September 30, 2012 and 2011 was:

Net Periodic Benefit Cost / (Income)	**Pension**		**Postretirement**	
	Successor	Predecessor	**Successor**	Predecessor
$ in millions	**2012**	2011	**2012**	2011
Service cost	**$ 4.6**	$ 3.7	**$ 0.1**	$ 0.1
Interest cost	**12.9**	12.7	**0.6**	0.7
Expected return on assets *(a)*	**(17.0)**	(18.4)	**(0.2)**	(0.2)
Amortization of unrecognized:				
Actuarial loss / (gain)	**3.7**	6.2	**(0.5)**	(0.9)
Prior service cost	**1.1**	1.6	**-**	0.1
Net periodic benefit cost / (income) before adjustments	**5.3**	5.8	**-**	(0.2)
Settlement cost *(b)*	**0.2**	-	**-**	-
Net periodic benefit cost / (income)	**$ 5.5**	$ 5.8	**$ -**	$ (0.2)

(a) *For purposes of calculating the expected return on pension plan assets, under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be included in the MRVA equally over a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets for the 2012 and 2011 net periodic benefit cost was approximately $336.0 million and $316.0 million, respectively.*

(b) *The settlement cost relates to a former officer who has elected to receive a lump sum distribution in 2012 from the Supplemental Executive Retirement Plan.*

Benefit payments, which reflect future service, are expected to be paid as follows:

Estimated Future Benefit Payments and Medicare Part D Reimbursements

$ in millions	Pension	Postretirement
2012	$ 5.8	$ 0.6
2013	22.7	2.3
2014	23.2	2.2
2015	23.8	2.0
2016	24.0	1.9
2017 - 2021	124.4	7.5

9. Fair Value Measurements

The fair values of our financial instruments are based on published sources for pricing when possible. We rely on valuation models only when no other methods exist. The value of our financial instruments represents our best estimates of the fair value, which may not be the value realized in the future.

The table below presents the fair value and cost of our non-derivative instruments at September 30, 2012 and December 31, 2011. See also Note 10 of Notes to Condensed Consolidated Financial Statements for the fair values of our derivative instruments.

	Successor			
	At September 30, 2012		At December 31, 2011	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
Assets				
Money Market Funds	**$ 0.2**	**$ 0.2**	$ 0.2	$ 0.2
Equity Securities	**3.9**	**5.2**	3.9	4.4
Debt Securities	**5.0**	**5.5**	5.0	5.5

Multi-Strategy Fund		**0.3**		**0.3**		0.3		0.2
Total Assets	**$**	**9.4**	**$**	**11.2**	$	9.4	$	10.3
Liabilities								
Debt	**$**	**2,614.9**	**$**	**2,769.4**	$	2,629.3	$	2,710.6

Debt

The carrying value of **DPL's** debt was adjusted to fair value at the Merger date. Unrealized gains or losses are not recognized in the financial statements because debt is presented at the value established at the Merger date, less amortized premium or discount. The debt amounts include the current portion payable in the next twelve months and have maturities that range from 2013 to 2061.

Master Trust Assets

DP&L established a Master Trust to hold assets that could be used for the benefit of employees participating in employee benefit plans. These assets are primarily comprised of open-ended mutual funds which are valued using the net asset value per unit. These investments are recorded at fair value within Other deferred assets on the balance sheets and classified as available for sale. Any unrealized gains or losses are recorded in AOCI until the securities are sold.

DP&L had $0.8 million ($0.5 million after tax) of unrealized gains and immaterial losses on the Master Trust assets in AOCI at September 30, 2012 and immaterial unrealized gains and losses in AOCI at December 31, 2011.

Due to the liquidation of the **DPL Inc.** common stock held in the Master Trust, there is sufficient cash to cover the next twelve months of benefits payable to employees covered under the benefit plans. Therefore, no unrealized gains or losses are expected to be transferred to earnings since we will not need to sell any investments in the next twelve months.

Net Asset Value (NAV) per Unit

The following table discloses the fair value and redemption frequency for those assets whose fair value is estimated using the NAV per unit as of September 30, 2012 and December 31, 2011. These assets are part of the Master Trust. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of September 30, 2012, **DPL** did not have any investments for sale at a price different from the NAV per unit.

Fair Value Estimated Using Net Asset Value per Unit (Successor)

$ in millions		**Fair Value at September 30, 2012**		Fair Value at December 31, 2011		Unfunded Commitments
Equity Securities (a)	**$**	**5.2**	$	4.4	$	-
Debt Securities (b)		**5.5**		5.5		-
Multi-Strategy Fund (c)		**0.3**		0.2		-
Total	**$**	**11.0**	$	10.1	$	-

(a)*This category includes investments in hedge funds representing an S&P 500 Index and the Morgan Stanley Capital International (MSCI) U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current net asset value per unit.*

(b)*This category includes investments in U.S. Treasury obligations and U.S. investment grade bonds. Investments in this category can be redeemed immediately at the current net asset value per unit.*

(c)*This category includes a mix of actively managed funds holding investments in stocks, bonds and short-term investments in a mix of actively managed funds. Investments in this category can be redeemed immediately at the current net asset value per unit.*

Fair Value Hierarchy

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. These inputs are then categorized as Level 1 (quoted prices in active markets for identical assets or liabilities); Level 2 (observable inputs such as quoted prices for similar assets or liabilities or quoted prices in markets that are not active); or Level 3 (unobservable inputs).

Valuations of assets and liabilities reflect the value of the instrument including the values associated with counterparty risk. We include our own credit risk and our counterparty's credit risk in our calculation of fair value using global average default rates based on an annual study conducted by a large rating agency.
We transferred a money market account to Level 1 from Level 2 of the fair value hierarchy, as it was determined that this fund is a cash equivalent where quoted prices are generally equal to par value.

The fair value of assets and liabilities at September 30, 2012 and December 31, 2011 measured on a recurring basis and the respective category within the fair value hierarchy for **DPL** was determined as follows:

Assets and Liabilities Measured at Fair Value on a Recurring Basis (Successor)

		Level 1	**Level 2**	**Level 3**
$ in millions	Fair Value at September 30, 2012	Based on Quoted Prices in Active Markets	Other Observable Inputs	Unobservable Inputs
Assets				
Master Trust Assets				
Money Market Funds	$ 0.2	$ 0.2	$ -	$ -
Equity Securities	5.2	-	5.2	-
Debt Securities	5.5	-	5.5	-
Multi-Strategy Fund	0.3	-	0.3	-
Total Master Trust Assets	11.2	0.2	11.0	-
Derivative Assets				
FTRs	0.1	-	-	0.1
Heating Oil Futures	0.4	0.4	-	-
Forward Power Contracts	16.8	-	16.8	-
Total Derivative Assets	17.3	0.4	16.8	0.1
Total Assets	$ 28.5	$ 0.6	$ 27.8	$ 0.1
Liabilities				
Derivative Liabilities				
Interest Rate Hedge	$ (35.7)	$ -	$ (35.7)	$ -
FTRs	(0.1)	-	-	(0.1)
Forward NYMEX Coal Contracts	(1.1)	-	(1.1)	-
Forward Power Contracts	(21.0)	-	(21.0)	-
Total Derivative Liabilities	(57.9)	-	(57.8)	(0.1)
Long-term Debt	(2,769.4)	-	(2,750.4)	(19.0)
Total Liabilities	$ (2,827.3)	$ -	$ (2,808.2)	$ (19.1)

Assets and Liabilities Measured at Fair Value on a Recurring Basis (Successor)

		Level 1	**Level 2**	**Level 3**
$ in millions	Fair Value as of December 31, 2011	Based on Quoted Prices in Active Markets	Other Observable Inputs	Unobservable Inputs
Assets				
Master Trust Assets				
Money Market Funds	$ 0.2	$ -	$ 0.2	$ -
Equity Securities	4.4	-	4.4	-
Debt Securities	5.5	-	5.5	-
Multi-Strategy Fund	0.2	-	0.2	-
Total Master Trust Assets	10.3	-	10.3	-
Derivative Assets				
FTRs	0.1	-	0.1	-

Heating Oil Futures	1.8	1.8	-	-
Forward Power Contracts	17.3	-	17.3	-
Total Derivative Assets	19.2	1.8	17.4	-
Total Assets	$ 29.5	$ 1.8	$ 27.7	$ -
Liabilities				
Derivative Liabilities				
Interest Rate Hedge	$ (32.5)	$ -	$ (32.5)	$ -
Forward NYMEX Coal Contracts	(14.5)	-	(14.5)	-
Forward Power Contracts	(13.3)	-	(13.3)	-
Total Derivative Liabilities	(60.3)	-	(60.3)	-
Total Liabilities	$ (60.3)	$ -	$ (60.3)	$ -

We use the market approach to value our financial instruments. Level 1 inputs are used for derivative contracts such as heating oil futures and for money market accounts that are considered cash equivalents. The fair value is determined by reference to quoted market prices and other relevant information generated by market transactions. Level 2 inputs are used to value derivatives such as forward power contracts and forward NYMEX-quality coal contracts (which are traded on the OTC market but which are valued using prices on the NYMEX for similar contracts on the OTC market). Other Level 2 assets include: open-ended mutual funds that are in the Master Trust, which are valued using the end of day NAV per unit; and interest rate hedges, which use observable inputs to populate a pricing model. Financial transmission rights are considered a Level 3 input, beginning April 1, 2012, because the monthly auctions are considered inactive.

Our Level 3 inputs are immaterial to our derivative balances as a whole and as such no further disclosures are presented.

Our debt is fair valued for disclosure purposes only and most of the fair values are determined using quoted market prices in inactive markets. These fair value inputs are considered Level 2 in the fair value hierarchy. Our long-term leases and the WPAFB loan are not publicly traded. Fair value is assumed to equal carrying value. These fair value inputs are considered Level 3 in the fair value hierarchy as there are no observable inputs. Additional Level 3 disclosures were not presented since debt is not recorded at fair value.

Approximately 99% of the inputs to the fair value of our derivative instruments are from quoted market prices.

Non-recurring Fair Value Measurements

We use the cost approach to determine the fair value of our AROs which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. Additions to AROs were not material during the nine months ended September 30, 2012 and 2011.

Cash Equivalents

DPL had $125.0 million and $125.0 million in money market funds classified as cash and cash equivalents in its Condensed Consolidated Balance Sheets at September 30, 2012 and December 31, 2011, respectively. The money market funds have quoted prices that are generally equivalent to par and are considered Level 1.

10. Derivative Instruments and Hedging Activities

In the normal course of business, **DPL** enters into various financial instruments, including derivative financial instruments. We use derivatives principally to manage the risk of changes in market prices for commodities and interest rate risk associated with our long-term debt. The derivatives that we use to economically hedge these risks are governed by our risk management policies for forward and futures contracts. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The objective of the hedging program is to mitigate financial risks while ensuring that we have adequate resources to meet our requirements. We monitor and value derivative positions monthly as part of our risk management processes. We use published sources for pricing, when possible, to mark positions to market. All of our derivative instruments are used for risk management purposes and are designated as cash flow hedges or marked to market each reporting period.

At September 30, 2012, **DPL** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	11.1	-	11.1

Heating Oil Futures	Mark to Market	Gallons	1,932.0	-	1,932.0
Forward Power Contracts	Cash Flow Hedge	MWh	886.2	(3,194.1)	(2,307.9)
Forward Power Contracts	Mark to Market	MWh	2,688.0	(4,877.6)	(2,189.6)
NYMEX-quality Coal Contracts*	Mark to Market	Tons	46.5	-	46.5
Interest Rate Swaps	Cash Flow Hedge	USD	$ 160,000.0	$ -	$ 160,000.0

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

At December 31, 2011, **DPL** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	7.1	(0.7)	6.4
Heating Oil Futures	Mark to Market	Gallons	2,772.0	-	2,772.0
Forward Power Contracts	Cash Flow Hedge	MWh	886.2	(341.6)	544.6
Forward Power Contracts	Mark to Market	MWh	1,769.4	(1,739.5)	29.9
NYMEX-quality Coal Contracts*	Mark to Market	Tons	2,015.0	-	2,015.0
Interest Rate Swaps	Cash Flow Hedge	USD	$ 160,000.0	$ -	$ 160,000.0

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

Cash Flow Hedges

As part of our risk management processes, we identify the relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking various hedge transactions. The fair value of cash flow hedges as determined by observable market prices available as of the balance sheet dates and will continue to fluctuate with changes in market prices up to contract expiration. The effective portion of the hedging transaction is recognized in AOCI and transferred to earnings using specific identification of each contract when the forecasted hedged transaction takes place or when the forecasted hedged transaction is probable of not occurring. The ineffective portion of the cash flow hedge is recognized in earnings in the current period. All risk components were taken into account to determine the hedge effectiveness of the cash flow hedges.

We enter into forward power contracts to manage commodity price risk exposure related to our generation of electricity. We do not hedge all commodity price risk. We reclassify gains and losses on forward power contracts from AOCI into earnings in those periods in which the contracts settle.

We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated 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. We do not hedge all interest rate exposure. During 2011, interest rate hedging relationships with a notional amount of $200.0 million settled resulting in **DPL** making a cash payment of $48.1 million ($31.3 million net of tax). As part of the Merger discussed in Note 2, **DPL** entered into a $425.0 million unsecured term loan agreement with a syndicated bank group on August 24, 2011, in part, to pay the approximately $297.4 million principal amount of **DPL's** 6.875% debt that was due in September 2011. The remainder was drawn for other corporate purposes. This agreement is for a three year term expiring on August 24, 2014. As a result, some of the forecasted transactions originally being hedged are probable of not occurring and therefore approximately $5.1 million ($3.3 million net of tax) has been reclassified to earnings during the period January 1, 2011 through November 27, 2011. Because the interest rate swap had already cash settled as of the Merger date, this hedge had no future value and was not valued as a part of the purchase accounting (See Note 2 for more information). We reclassify gains and losses on interest rate derivative hedges related to debt financings from AOCI into earnings in those periods in which hedged interest payments occur.

The following table provides information for **DPL** concerning gains or losses recognized in AOCI for the cash flow hedges for the three months ended September 30, 2012 and 2011:

	Three Months Ended September 30, 2012		Three Months Ended September 30, 2011	
	Successor		Predecessor	
$ in millions (net of tax)	Power	Interest Rate Hedge	Power	Interest Rate Hedge

Beginning accumulated derivative gain / (loss) in AOCI	$ (2.4)	$ (4.7)	$ (1.5)	$ 12.3
Net gains / (losses) associated with current period hedging transactions	(2.2)	2.5	1.8	(49.8)
Net gains reclassified to earnings				
Interest Expense	-	-	-	1.4
Revenues	(0.1)	-	0.1	-
Purchased Power	0.1	-	-	-
Ending accumulated derivative gain / (loss) in AOCI	$ (4.6)	$ (2.2)	$ 0.4	$ (36.1)
Net gains / (losses) associated with the ineffective portion of the hedging transaction				
Interest Expense	$ -	$ -	$ -	$ 3.1
Revenues	$ -	$ -	$ -	$ -
Purchased Power	$ -	$ -	$ -	$ -
Portion expected to be reclassified to earnings in the next twelve months*	$ (7.9)	$ -		
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	27	12		

*The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

The following table provides information for **DPL** concerning gains or losses recognized in AOCI for the cash flow hedges for the nine months ended September 30, 2012 and 2011:

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
	Successor		Predecessor	
$ in millions (net of tax)	Power	Interest Rate Hedge	Power	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	$ 0.3	$ (0.8)	$ (1.8)	$ 21.4
Net gains / (losses) associated with current period hedging transactions	(3.8)	(1.7)	0.8	(59.0)
Net gains reclassified to earnings				
Interest Expense	-	0.3	-	1.5
Revenues	(0.1)	-	0.8	-
Purchased Power	(1.0)	-	0.6	-
Ending accumulated derivative gain / (loss) in AOCI	$ (4.6)	$ (2.2)	$ 0.4	$ (36.1)
Net gains / (losses) associated with the ineffective portion of the hedging transaction				
Interest Expense	$ -	$ (1.2)	$ -	$ 5.1
Revenues	$ -	$ -	$ -	$ -
Purchased Power	$ -	$ -	$ -	$ -
Portion expected to be reclassified to earnings in the next twelve months*	$ (7.9)	$ -		
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	27	12		

*The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

The following tables show the fair value and balance sheet classification of **DPL's** derivative instruments designated as hedging instruments at September 30, 2012 and December 31, 2011:

Fair Values of Derivative Instruments Designated as Hedging Instruments
At September 30, 2012 (Successor)

$ in millions		Fair Value	Balance Sheet Location
Short-term Derivative Positions			
Forward Power Contracts in an Asset Position	**$**	**0.4**	Other prepayments and current assets
Forward Power Contracts in a Liability Position		**(7.3)**	Other current liabilities
Total Short-term Cash Flow Hedges		**(6.9)**	
Long-term Derivative Positions			
Forward Power Contracts in an Asset Position		**0.7**	Other deferred assets
Forward Power Contracts in a Liability Position		**(3.0)**	Other deferred credits
Interest Rate Hedges in a Liability Position		**(35.7)**	Other deferred credits
Total Long-term Cash Flow Hedges		**(38.0)**	
Total Cash Flow Hedges	**$**	**(44.9)**	

Fair Values of Derivative Instruments Designated as Hedging Instruments
at December 31, 2011 (Successor)

$ in millions		Fair Value	Balance Sheet Location
Short-term Derivative Positions			
Forward Power Contracts in an Asset Position	$	1.5	Other prepayments and current assets
Forward Power Contracts in a Liability Position		(0.2)	Other current liabilities
Total Short-term Cash Flow Hedges		1.3	
Long-term Derivative Positions			
Forward Power Contracts in an Asset Position		0.1	Other deferred assets
Forward Power Contracts in a Liability Position		(2.6)	Other deferred credits
Interest Rate Hedges in a Liability Position		(32.5)	Other deferred credits
Total Long-term Cash Flow Hedges		(35.0)	
Total Cash Flow Hedges	$	(33.7)	

Mark to Market Accounting

Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for hedge accounting or the normal purchase and sales exceptions under FASC Topic 815. Accordingly, such contracts are recorded at fair value with changes in the fair value charged or credited to the Condensed Consolidated Statements of Results of Operations in the period in which the change occurred. This is commonly referred to as "MTM accounting." Contracts we enter into as part of our risk management program may be settled financially, by physical delivery or net settled with the counterparty. We currently mark to market Financial Transmission Rights (FTRs), heating oil futures, forward NYMEX-quality coal contracts and certain forward power contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided under GAAP. Derivative contracts that have been designated as normal purchases or normal sales under GAAP are not subject to MTM accounting treatment and are recognized in the Condensed Consolidated Statements of Results of Operations on an accrual basis.

Regulatory Assets and Liabilities

In accordance with regulatory accounting under GAAP, a cost that is probable of recovery in future rates should be deferred as a regulatory asset and a gain that is probable of being returned to customers should be deferred as a regulatory liability. Portions of the derivative contracts that are marked to market each reporting period and are related to the retail portion of **DP&L's** load requirements are included as part of the fuel and purchased power recovery rider approved by the PUCO which began January 1, 2010. Therefore, the Ohio retail customers' portion of the heating oil futures and the NYMEX-quality coal contracts are deferred as a regulatory asset or liability until the contracts settle. If these unrealized gains and losses are no longer deemed to be probable of recovery through our rates, they will be reclassified into earnings in the period such determination is made.

The following tables show the amount and classification within the Condensed Consolidated Statements of Results of Operations or Condensed Consolidated Balance Sheets of the gains and losses on **DPL's** derivatives not designated as hedging instruments for the three and nine months ended September 30, 2012 and 2011.

For the three months ended September 30, 2012 (Successor)

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 15.5	$ -	$ 0.1	$ (2.9)	$ 12.7
Realized gain / (loss)	(12.8)	0.5	0.1	0.1	(12.1)
Total	$ 2.7	$ 0.5	$ 0.2	$ (2.8)	$ 0.6
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 4.7	$ -	$ -	$ -	$ 4.7
Regulatory (asset) / liability	1.2	(0.1)	-	-	1.1
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(2.4)	(2.4)
Purchased Power	-	-	0.2	(0.4)	(0.2)
Fuel	(3.2)	0.5	-	-	(2.7)
O&M	-	0.1	-	-	0.1
Total	$ 2.7	$ 0.5	$ 0.2	$ (2.8)	$ 0.6

For the three months ended September 30, 2011 (Predecessor)

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ (27.9)	$ (1.6)	$ (0.1)	$ (0.3)	$ (29.9)
Realized gain / (loss)	4.3	0.5	-	1.2	6.0
Total	$ (23.6)	$ (1.1)	$ (0.1)	$ 0.9	$ (23.9)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ (13.8)	$ -	$ -	$ -	$ (13.8)
Regulatory (asset) / liability	(4.0)	(0.6)	-	-	(4.6)
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(1.6)	(1.6)
Purchased Power	-	-	(0.1)	2.5	2.4
Fuel	(5.8)	(0.5)	-	-	(6.3)
O&M	-	-	-	-	-
Total	$ (23.6)	$ (1.1)	$ (0.1)	$ 0.9	$ (23.9)

For the nine months ended September 30, 2012 (Successor)

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 13.4	$ (1.5)	$ (0.1)	$ (0.6)	$ 11.2
Realized gain / (loss)	(27.2)	1.9	0.5	(4.2)	(29.0)
Total	$ (13.8)	$ 0.4	$ 0.4	$ (4.8)	$ (17.8)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 3.5	$ -	$ -	$ -	$ 3.5
Regulatory (asset) / liability	0.9	(0.6)	-	-	0.3
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(1.7)	(1.7)
Purchased Power	-	-	0.4	(3.1)	(2.7)
Fuel	(18.2)	0.8	-	-	(17.4)
O&M	-	0.2	-	-	0.2
Total	$ (13.8)	$ 0.4	$ 0.4	$ (4.8)	$ (17.8)

For the nine months ended September 30, 2011 (Predecessor)

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total

Change in unrealized gain / (loss)	$ (41.6)	$ -	$ (0.1)	$ 0.6	$ (41.1)
Realized gain / (loss)	8.1	1.5	(0.6)	(0.8)	8.2
Total	$ (33.5)	$ 1.5	$ (0.7)	$ (0.2)	$ (32.9)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ (21.2)	$ -	$ -	$ -	$ (21.2)
Regulatory (asset) / liability	(5.9)	0.1	-	-	(5.8)
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(6.3)	(6.3)
Purchased Power	-	-	(0.7)	6.1	5.4
Fuel	(6.4)	1.3	-	-	(5.1)
O&M	-	0.1	-	-	0.1
Total	$ (33.5)	$ 1.5	$ (0.7)	$ (0.2)	$ (32.9)

The following table shows the fair value and balance sheet classification of **DPL's** derivative instruments not designated as hedging instruments at September 30, 2012:

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
At September 30, 2012 (Successor)

$ in millions	Fair Value	Balance Sheet Location
Short-term Derivative Positions		
FTRs in an Asset Position	**$ 0.1**	Other prepayments and current assets
FTRs in a Liability Position	**(0.1)**	Other current liabilities
Forward Power Contracts in an Asset Position	**12.0**	Other prepayments and current assets
Forward Power Contracts in a Liability Position	**(8.3)**	Other current liabilities
NYMEX-quality Coal Forwards in a Liability Position	**(1.1)**	Other current liabilities
Heating Oil Futures in an Asset Position	**0.3**	Other prepayments and current assets
Total Short-term Derivative MTM Positions	**2.9**	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	**3.7**	Other deferred assets
Forward Power Contracts in a Liability Position	**(2.4)**	Other deferred credits
NYMEX-quality Coal Forwards in a Liability Position	**-**	Other deferred credits
Heating Oil Futures in an Asset Position	**0.1**	Other deferred assets
Total Long-term Derivative MTM Positions	**1.4**	
Net MTM Position	**$ 4.3**	

The following table shows the fair value and balance sheet classification of **DPL's** derivative instruments not designated as hedging instruments at December 31, 2011:

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
at December 31, 2011 (Successor)

$ in millions	Fair Value	Balance Sheet Location
Short-term Derivative Positions		
FTRs in an Asset Position	$ 0.1	Other current liabilities
Forward Power Contracts in an Asset Position	9.9	Other prepayments and current assets
Forward Power Contracts in a Liability Position	(6.5)	Other current liabilities
NYMEX-quality Coal Forwards in a Liability Position	(8.3)	Other current liabilities
Heating Oil Futures in an Asset Position	1.8	Other prepayments and current assets
Total Short-term Derivative MTM Positions	(3.0)	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	5.8	Other deferred assets
Forward Power Contracts in a Liability Position	(4.0)	Other deferred credits
NYMEX-quality Coal Forwards in a Liability Position	(6.2)	Other deferred credits

Total Long-term Derivative MTM Positions		(4.4)
Net MTM Position	$	(7.4)

Certain of our OTC commodity derivative contracts are under master netting agreements that contain provisions that require our debt to maintain an investment grade credit rating from credit rating agencies. Even though our debt has fallen below investment grade, our counterparties to the derivative instruments have not requested immediate payment or demanded immediate and ongoing full overnight collateralization of the MTM loss.

The aggregate fair value of **DPL's** commodity derivative instruments that are in a MTM loss position at September 30, 2012 is $22.2 million. This amount is offset by $12.6 million of collateral posted directly with third parties and in a broker margin account which offsets our loss positions on the forward contracts. This liability position is further offset by the asset position of counterparties with master netting agreements of $4.4 million. If our counterparties were to call for collateral, we could have to post collateral for the remaining $5.2 million.

11. Common Shareholder's Equity

Effective on the Merger date, **DPL** adopted Amended Articles of Incorporation providing for 1,500 authorized common shares, of which one share is outstanding at September 30, 2012.

On October 28, 2009, the **DPL** Board of Directors approved a Stock Repurchase Program that permitted **DPL** to use proceeds from the exercise of **DPL** warrants by warrant holders to repurchase other outstanding **DPL** warrants or its common stock from time to time in the open market, through private transactions or otherwise. This 2009 Stock Repurchase Program was scheduled to run through June 30, 2012, but was suspended in connection with the Merger with The AES Corporation, discussed in Note 2. In June 2011, 0.7 million warrants were exercised with proceeds of $14.7 million. Since the Stock Repurchase Program was suspended, the proceeds from the June 2011 exercise of warrants were not used to repurchase stock.

As a result of the Merger involving **DPL** and AES, the outstanding shares of **DPL** common stock were converted into the right to receive merger consideration of $30.00 per share. When the remaining warrants were exercised in March 2012, **DPL** paid the warrant holders an amount equal to $9.00 per warrant, which was

the difference between the merger consideration of $30.00 per share of **DPL** common stock and the exercise price of $21.00 per share. This amount was recorded as a $9.0 million liability at the Merger date. At December 31, 2011, **DPL** had 1.0 million outstanding warrants which were exercised in March 2012. At September 30, 2012, there are no remaining warrants outstanding.

ESOP

In October 1992, our Board of Directors approved the formation of a Company-sponsored ESOP to fund matching contributions to **DP&L's** 401(k) retirement savings plan and certain other payments to eligible full-time employees. ESOP shares used to fund matching contributions to **DP&L's** 401(k) vested after two, three or five years of service in accordance with the match formula effective for the respective plan match year; other compensation shares awarded vested immediately.

During December 2011, the ESOP Plan was terminated and participant balances were transferred to one of the two **DP&L** sponsored defined contribution 401(k) plans. On December 5, 2011, the ESOP Trust paid the total outstanding principal and interest of $68.2 million on the loan with **DPL**, using the merger proceeds from unallocated **DPL** common stock held within the ESOP suspense account.

12. Earnings per Share

Basic EPS is based on the weighted-average number of **DPL** common shares outstanding during the year. Diluted EPS is based on the weighted-average number of **DPL** common and common-equivalent shares outstanding during the year, except in periods where the inclusion of such common-equivalent shares is anti-dilutive. Excluded from outstanding shares for these weighted-average computations during 2011 were shares held by **DP&L's** Master Trust Plan for deferred compensation and unreleased shares held by **DPL's** ESOP.

The common-equivalent shares excluded from the calculation of diluted EPS, because they were anti-dilutive, were not material for the three and nine months ended September 30, 2011. Effective with the Merger with AES, **DPL** is an indirectly wholly owned subsidiary of AES and earnings per share information is no longer required.

The following illustrates the reconciliation of the numerators and denominators of the basic and diluted EPS computations:

	Successor	Predecessor
	Three Months Ended	Three Months Ended

	Successor			Predecessor		
	September 30, 2012			September 30, 2011		
$ and shares in millions except per share amounts	Income	Shares	Per Share	Income	Shares	Per Share
Basic EPS	N/A	N/A	N/A	$ 67.1	115.0	$ 0.6
Effect of Dilutive Securities:						
Warrants		N/A			0.3	
Stock options, performance and restricted shares		N/A			0.2	
Diluted EPS	N/A	N/A	N/A	$ 67.1	115.5	$ 0.6

	Successor			Predecessor		
	Nine Months Ended September 30, 2012			Nine Months Ended September 30, 2011		
$ and shares in millions except per share amounts	Income	Shares	Per Share	Income	Shares	Per Share
Basic EPS	N/A	N/A	N/A	$ 142.3	114.4	$ 1.2
Effect of Dilutive Securities:						
Warrants		N/A			0.4	
Stock options, performance and restricted shares		N/A			0.2	
Diluted EPS	N/A	N/A	N/A	$ 142.3	115.0	$ 1.2

13. Contractual Obligations, Commercial Commitments and Contingencies

DPL Inc. – Guarantees

In the normal course of business, **DPL** enters into various agreements with its wholly owned subsidiaries, DPLE and DPLER and its wholly owned subsidiary, MC Squared, providing financial or performance assurance to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to these subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish these subsidiaries' intended commercial purposes.

At September 30, 2012, **DPL** had $24.4 million of guarantees to third parties for future financial or performance assurance under such agreements, including $24.1 million of guarantees, on behalf of DPLE and DPLER and $0.3 million of guarantees on behalf of MC Squared. The guarantee arrangements entered into by **DPL** with these third parties cover select present and future obligations of DPLE, DPLER and MC Squared to such beneficiaries and are terminable by **DPL** upon written notice within a certain time to the beneficiaries. The carrying amount of obligations for commercial transactions covered by these guarantees and recorded in our Condensed Consolidated Balance Sheets was $1.0 million at September 30, 2012.

To date, **DPL** has not incurred any losses related to the guarantees of DPLE's, DPLER's and MC Squared's obligations and we believe it is remote that **DPL** would be required to perform or incur any losses in the future associated with any of the above guarantees of DPLE's, DPLER's and MC Squared's obligations.

Equity Ownership Interest

DP&L owns a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. As of September 30, 2012, **DP&L** could be responsible for the repayment of 4.9%, or $78.8 million, of a $1,607.8 million debt obligation that features maturities from 2013 to 2040. This would only happen if this electric generation company defaulted on its debt payments. As of September 30, 2012, we have no knowledge of such a default.

Commercial Commitments and Contractual Obligations

There have been no material changes, outside the ordinary course of business, to our commercial commitments and to the information disclosed in the contractual obligations table in our Form 10-K for the fiscal year ended December 31, 2011.

Contingencies

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our Condensed Consolidated Financial Statements, as prescribed by GAAP, are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims, tax examinations and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our Condensed Consolidated Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of September 30, 2012, cannot be reasonably determined.

Environmental Matters

DPL, **DP&L** and our subsidiaries' facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. As well as imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at these facilities to comply, or to determine compliance, with such regulations. We record liabilities for losses that are probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. We have estimated liabilities of approximately $4.0 million for environmental matters. We evaluate the potential liability related to probable losses quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material adverse effect on our results of operations, financial condition or cash flows.

We have several pending environmental matters associated with our power plants. Some of these matters could have material adverse impacts on our business and on the operation of the power plants; especially the plants that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired power plants that do not have this equipment installed. **DP&L** owns 100% of the Hutchings station and a 50% interest in Beckjord Unit 6.

On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our jointly owned Unit 6, in December 2014. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. Beckjord Unit 6 was valued at zero at the Merger date.

We are considering options for the Hutchings station, but have not yet made a final decision. **DP&L** has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated and unavailable for service until at least June 1, 2014, if not indeterminately. In addition, **DP&L** has notified PJM that Hutchings Units 1 and 2 will be deactivated by June 1, 2015. Hutchings was valued at zero at the Merger date.

DPL revalued **DP&L's** investment in the above plants at the estimated fair value for each plant at the Merger date.

Environmental Matters Related to Air Quality

Clean Air Act Compliance

In 1990, the federal government amended the CAA to further regulate air pollution. Under the CAA, the USEPA sets limits on, among other things, how much of certain designated pollutants can be in the ambient air anywhere in the United States. The CAA allows individual states to have stronger pollution controls than those set under the CAA, but states are not allowed to have weaker pollution controls than those set for the whole country. The CAA has a material effect on our operations and such effects are detailed below with respect to certain programs under the CAA.

Cross-State Air Pollution Rule

The USEPA promulgated the "Clean Air Interstate Rule" (CAIR) on March 10, 2005, which required allowance surrender for SO_2 and NOx emissions from existing power plants located in 28 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase was to begin in 2009 and 2010 for NOx and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions was to begin in 2015. To implement the required emission reductions for this rule, the states were to establish emission allowance based "cap-and-trade" programs. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the USEPA.

In response to the D.C. Circuit's opinion, on July 7, 2011, the USEPA issued a final rule titled "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States," which is now referred to as the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, CSAPR would have required significant reductions in SO_2 and NOx emissions from covered sources, such as power plants. Once fully implemented in 2014, the rule would require additional SO_2 emission reductions of 73% and additional NOx reductions of 54% from 2005 levels. Many states, utilities and other affected parties filed petitions for review, challenging the CSAPR before the U.S. Court of Appeals for the District of Columbia. A large subset of the Petitioners also sought a stay of the CSAPR. On December 30, 2011, the D.C. Circuit granted a stay of the CSAPR and directed the USEPA to continue administering CAIR. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that USEPA overstepped its regulatory authority by requiring states to make reductions beyond the levels required in the CAA and failed to provide states an initial opportunity to adopt their own measures for achieving federal compliance. As a result of this ruling, the surviving provisions of CAIR will continue to serve as the governing program until USEPA takes further action or the U.S. Congress intervenes. Assuming that USEPA constructs a replacement interstate transport rule addressing the D.C. Circuit Court's ruling, it will likely take three years or more before companies would be required to comply with a replacement rule. At this time, it is not possible to predict the details of such a replacement transport rule or what impacts it may have on our consolidated financial condition, results of operations or cash flows. On October 5, 2012, USEPA, several states and cities, as well as environmental and health organizations, filed petitions with the D.C. Circuit Court requesting a rehearing by all of the judges of the D.C. Circuit Court of the case pursuant to which the three-judge panel ruled that CSAPR be vacated. As of November 6, 2012, the D.C. Circuit Court had not ruled on USEPA's petition for rehearing. We cannot predict whether the D.C. Circuit Court will grant a rehearing or, if a rehearing is granted, whether CSAPR will be ultimately reinstated and implemented in its current form or a modified form. If CSAPR were to be reinstated in its current form, we do not expect any material capital costs for **DP&L's** plants, assuming Beckjord 6 and Hutchings generating stations will not operate on coal in 2015 due to implementation of the Mercury and Air Toxics Standards. Because we cannot predict the final outcome of the CSAPR rulemaking, we cannot predict its financial impact on **DP&L's** operations.

Mercury and Other Hazardous Air Pollutants

On May 3, 2011, the USEPA published proposed Maximum Achievable Control Technology (MACT) standards for coal- and oil-fired electric generating units. The standards include new requirements for emissions of mercury and a number of other heavy metals. The USEPA Administrator signed the final rule, now called MATS (Mercury and Air Toxics Standards), on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Affected electric generating units (EGUs) will have to come into compliance with the new requirements by April 16, 2015, but may be granted an additional year contingent on Ohio EPA approval. **DP&L** is evaluating the costs that may be incurred to comply with the new requirement; however, MATS is expected to have a material adverse effect on our uncontrolled units.

On April 29, 2010, the USEPA issued a proposed rule that would reduce emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers, and process heaters at major and area source facilities. The final rule was published in the Federal Register on March 21, 2011. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulations contain emissions limitations, operating limitations and other requirements. In December 2011, the USEPA proposed additional changes to this rule and solicited comments. Compliance costs are not expected to be material to **DP&L's** operations.

On May 3, 2010, the USEPA finalized the "National Emissions Standards for Hazardous Air Pollutants" for compression ignition (CI) reciprocating internal combustion engines (RICE). The units affected at **DP&L** are 18 diesel electric generating engines and eight emergency "black start" engines. The existing CI RICE units must comply by May 3, 2013. The regulations contain emissions limitations, operating limitations and other requirements. Compliance costs for **DP&L's** operations are not expected to be material.

Carbon and Other Greenhouse Gas Emissions

In response to a U.S. Supreme Court decision that the USEPA has the authority to regulate CO_2 emissions from motor vehicles, the USEPA made a finding that CO_2 and certain other GHGs are pollutants under the CAA. Subsequently, under the CAA, USEPA determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This finding became effective in January 2010. Numerous affected parties have petitioned the USEPA Administrator to reconsider this decision. On April 1, 2010, USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under USEPA's view, this is the final action that renders CO_2 and other GHGs "regulated air pollutants" under the CAA.

Under USEPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the USEPA began regulating GHG emissions from certain stationary sources in January 2011. The Tailoring Rule sets forth criteria for determining which facilities are required to obtain permits for their GHG emissions pursuant to the CAA Prevention of Significant Deterioration and Title V operating permit programs. Under the Tailoring Rule, permitting requirements are being phased in through successive steps that may expand the scope of covered sources over time. The USEPA has issued guidance on what the best available control technology entails for the control of GHGs and individual states are required to determine what controls are required for facilities on a case-by-case basis. The ultimate impact of the Tailoring Rule to **DP&L** cannot be determined at this time, but the cost of compliance could be material.

On April 13, 2012, the USEPA published its proposed GHG standards for new electric generating units (EGUs) under CAA subsection 111(b), which would require certain new EGUs to meet a standard of 1,000 pounds of CO_2 per megawatt-hour, a standard based on the emissions limitations achievable through natural gas combined cycle generation. The proposal anticipates that affected coal-fired units would need to install carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. Furthermore, the USEPA may propose and promulgate guidelines for states to address GHG standards for existing EGUs under CAA subsection 111(d). These latter rules may focus on energy efficiency improvements at power plants. We cannot predict the effect of these standards, if any, on **DP&L's** operations.

Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 16 million tons annually. Further GHG legislation or regulation finalized at a future date could have a significant effect on **DP&L's** operations and costs, which could adversely affect our net income, cash flows and financial condition. However, due to the uncertainty associated with such legislation or regulation, we cannot predict the final outcome or the financial impact that such legislation or regulation may have on **DP&L**.

On September 22, 2009, the USEPA issued a final rule for mandatory reporting of GHGs from large sources that emit 25,000 metric tons per year or more of GHGs, including EGUs. **DP&L** has submitted to USEPA GHG emission reports for 2011 and 2010. While this reporting rule will guide development of policies and programs to reduce emissions, **DP&L** does not anticipate that the reporting rule will itself result in any significant cost or other effect on current operations.

Litigation, Notices of Violation and Other Matters Related to Air Quality

Litigation Involving Co-Owned Plants

On June 20, 2011, the U.S. Supreme Court ruled that the USEPA's regulation of GHGs under the CAA displaced any right that plaintiffs may have had to seek similar regulation through federal common law litigation in the court system. Although we are not named as a party to these lawsuits, **DP&L** is a co-owner of coal-fired plants with Duke Energy and AEP (or their subsidiaries) that could have been affected by the outcome of these lawsuits or similar suits that may have been filed against other electric power companies, including **DP&L**. Because the issue was not squarely before it, the U.S. Supreme Court did not rule against the portion of plaintiffs' original suits that sought relief under state law.

As a result of a 2008 consent decree entered into with the Sierra Club and approved by the U.S. District Court for the Southern District of Ohio, **DP&L** and the other owners of the J.M. Stuart generating station are subject to certain specified emission targets related to NOx, SO_2 and particulate matter. The consent decree also includes commitments for energy efficiency and renewable energy activities. An amendment to the consent decree was entered into and approved in 2010 to clarify how emissions would be computed during malfunctions. Continued compliance with the consent decree, as amended, is not expected to have a material effect on **DP&L's** results of operations, financial condition or cash flows in the future.

Notices of Violation Involving Co-Owned Plants

In November 1999, the USEPA filed civil complaints and NOVs against operators and owners of certain generation facilities for alleged violations of the CAA. Generation units operated by Duke Energy (Beckjord Unit 6) and CSP (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. Although **DP&L** was not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect **DP&L's** co-owned plants.

In June 2000, the USEPA issued an NOV to the **DP&L**-operated J.M. Stuart generating station (co-owned by **DP&L**, Duke Energy, and CSP) for alleged violations of the CAA. The NOV contained allegations that Stuart station engaged in projects between 1978 and 2000 without New Source Review and Prevention of Significant Deterioration permits that resulted in significant increases in particulate matter, SO_2, and NOx. These allegations are consistent with NOVs and complaints that the USEPA had brought against numerous other coal-fired utilities in the Midwest. The NOV indicated the USEPA may: (1) issue an order requiring compliance with the requirements of the

Ohio SIP; or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. To date, neither action has been taken. **DP&L** cannot predict the outcome of this matter.

In December 2007, the Ohio EPA issued an NOV to the **DP&L**-operated Killen generating station (co-owned by **DP&L** and Duke Energy) for alleged violations of the CAA. The NOV alleged deficiencies in the continuous monitoring of opacity. We submitted a compliance plan to the Ohio EPA on December 19, 2007. To date, no further actions have been taken by the Ohio EPA.

On March 13, 2008, Duke Energy, the operator of the Zimmer generating station, received an NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio State Implementation Program (SIP) and permits for the station in areas including SO_2, opacity and increased heat input. A second NOV and FOV with similar allegations was issued on November 4, 2010. Also in 2010, USEPA issued an NOV to Zimmer for excess emissions. **DP&L** is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of these matters. Duke Energy is expected to act on behalf of itself and the co-owners with respect to these matters. **DP&L** is unable to predict the outcome of these matters.

Notices of Violation Involving Wholly Owned Plants

In 2007, the Ohio EPA and the USEPA issued NOVs to **DP&L** for alleged violations of the CAA at the Hutchings station. The NOVs' alleged deficiencies relate to stack opacity and particulate emissions. Discussions are under way with the USEPA, the U.S. Department of Justice and Ohio EPA. On November 18, 2009, the USEPA issued an NOV to **DP&L** for alleged NSR violations of the CAA at the Hutchings station relating to capital projects performed in 2001 involving Unit 3 and Unit 6. **DP&L** does not believe that the projects described in the NOV were modifications subject to NSR. **DP&L** is engaged in discussions with the USEPA and the U.S. Department of Justice to resolve these matters, but **DP&L** is unable to determine the timing, costs or method by which these issues may be resolved. The Ohio EPA is kept apprised of these discussions.

Environmental Matters Related to Water Quality, Waste Disposal and Ash Ponds

Clean Water Act – Regulation of Water Intake

On July 9, 2004, the USEPA issued final rules pursuant to the Clean Water Act governing existing facilities that have cooling water intake structures. The rules require an assessment of impingement and/or entrainment of organisms as a result of cooling water withdrawal. A number of parties appealed the rules. In April 2009, the U.S. Supreme Court ruled that the USEPA did have the authority to compare costs with benefits in determining best technology available. The USEPA released new proposed regulations on March 28, 2011, published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. It is anticipated that the final rules will be promulgated in mid-2013. We do not yet know the effect these proposed rules will have on our operations.

Clean Water Act – Regulation of Water Discharge

In December 2006, we submitted an application for the renewal of the Stuart station NPDES Permit that was due to expire on June 30, 2007. In July 2007, we received a draft permit proposing to continue our authority to discharge water from the station into the Ohio River. On February 5, 2008, we received a letter from the Ohio EPA indicating that they intended to impose a compliance schedule as part of the final Permit, that requires us to implement one of two diffuser options for the discharge of water from the station into the Ohio River as identified in a thermal discharge study completed during the previous permit term. Subsequently, **DP&L** and the Ohio EPA reached an agreement to allow **DP&L** to restrict public access to the water discharge area as an alternative to installing one of the diffuser options. Ohio EPA issued a revised draft permit that was received on November 12, 2008. In December 2008, the USEPA requested that the Ohio EPA provide additional information regarding the thermal discharge in the draft permit. In June 2009, **DP&L** provided information to the USEPA in response to their request to the Ohio EPA. In September 2010, the USEPA formally objected to a revised permit provided by Ohio EPA due to questions regarding the basis for the alternate thermal limitation. In December 2010, **DP&L** requested a public hearing on the objection, which was held on March 23, 2011. We participated in and presented our position on the issue at the hearing and in written comments submitted on April 28, 2011. In a letter to the Ohio EPA dated September 28, 2011, the USEPA reaffirmed its objection to the revised permit as previously drafted by the Ohio EPA. This reaffirmation stipulated that if the Ohio EPA does not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit will pass to the USEPA. The Ohio EPA issued another draft permit in December 2011 and a public hearing was held on February 2, 2012. The draft permit would require **DP&L**, over the 54 months following issuance of a final permit, to take undefined actions to lower the temperature of its discharged water to a level unachievable by the station under its current design or alternatively make other significant modifications to the cooling water system. **DP&L** submitted comments to the draft permit and is considering legal options. On May 17, 2012, we met with Ohio EPA to discuss this matter. In late August 2012, Ohio EPA provided **DP&L** with a revised draft permit which included some modifications based on our previous comments. We are reviewing this revised draft. Depending on the outcome of the process, the effects could be material on **DP&L's** operations.

In September 2009, the USEPA announced that it will be revising technology-based regulations governing water discharges from steam electric generating facilities. The rulemaking included the collection of information via an industry-wide questionnaire as well as targeted water sampling efforts at selected facilities. It is anticipated that the USEPA will release a proposed rule by late 2012 with a final regulation in place by mid-2014. At present, **DP&L** is unable to predict the impact this rulemaking will have on its operations.

In April 2012, **DP&L** received an NOV related to the construction of the Carter Hollow landfill at the J.M. Stuart station. The NOV indicated that construction activities caused sediment to flow into downstream creeks. In addition, the U.S. Army Corps of Engineers issued a Cease and Desist order followed by a notice suspending the previously issued Corps permit authorizing work associated with the landfill. **DP&L** has installed sedimentation ponds as part of the runoff control measures to address this issue and is working with the various agencies to resolve their concerns including entering into settlement discussions with USEPA, although they have not issued any formal Notice of Violation. This may affect the landfill's construction schedule and delay its operational date. **DP&L** has accrued an immaterial amount for anticipated penalties related to this issue.

Regulation of Waste Disposal

In September 2002, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the South Dayton Dump landfill site. In August 2005, **DP&L** and other parties received a general notice regarding the performance of a Remedial Investigation and Feasibility Study (RI/FS) under a Superfund Alternative Approach. In October 2005, **DP&L** received a special notice letter inviting it to enter into negotiations with the USEPA to conduct the RI/FS. No recent activity has occurred with respect to that notice or PRP status. However, on August 25, 2009, the USEPA issued an Administrative Order requiring that access to **DP&L's** service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. **DP&L** granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against **DP&L** and numerous other defendants alleging that **DP&L** and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site. On February 10, 2011, the Court dismissed claims against **DP&L** that related to allegations that chemicals used by **DP&L** at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from **DP&L** that were allegedly directly delivered by truck to the landfill. Discovery, including depositions of past and present **DP&L** employees, is ongoing. In June 2012, **DP&L** filed a motion for summary judgment on grounds that the remaining claims for contribution are barred by a statute of limitations. The plaintiffs opposed that motion and, additionally, have filed a motion seeking Court leave to amend their complaint to add more than 20 new defendants to the case and to recharacterize and re-allege claims against **DP&L** that the Court dismissed in its February 10, 2011 order. On October 26, 2012, **DP&L** received another request to access **DP&L's** service center building site to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. While **DP&L** is unable to predict the outcome of these matters, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on its operations.

In December 2003, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the Tremont City landfill site. Information available to **DP&L** does not demonstrate that it contributed hazardous substances to the site. While **DP&L** is unable to predict the outcome of this matter, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on its operations.

On April 7, 2010, the USEPA published an Advance Notice of Proposed Rulemaking announcing that it is reassessing existing regulations governing the use and distribution in commerce of polychlorinated biphenyls (PCBs). While this reassessment is in the early stages and the USEPA is evaluating information from potentially affected parties on how it should proceed, the outcome may have a material adverse effect on **DP&L**. The USEPA has indicated that a proposed rule will be released in late 2012 or early 2013. At present, **DP&L** is unable to predict the impact this initiative will have on its operations.

Regulation of Ash Ponds

In March 2009, the USEPA, through a formal Information Collection Request, collected information on ash pond facilities across the country, including those at Killen and J.M. Stuart stations. Subsequently, the USEPA collected similar information for the Hutchings station.

In August 2010, the USEPA conducted an inspection of the Hutchings station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the Hutchings station ash ponds. **DP&L** is unable to predict whether there will be additional USEPA action relative to **DP&L's** proposed plan or the effect on operations that might arise under a different plan.

In June 2011, the USEPA conducted an inspection of the Killen station ash ponds. In June 2012, the USEPA issued a draft report from the inspection that noted no significant issues with the ash ponds. **DP&L** provided comments on the draft report and **DP&L** is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion byproducts under the Resource Conservation Recovery Act (RCRA). On June 21, 2010, the USEPA published a proposed rule seeking comments on two options under consideration for the regulation of coal combustion byproducts including regulating the material as a hazardous waste under RCRA Subtitle C or as a solid waste under RCRA Subtitle D. The USEPA anticipates issuing a final rule on this topic in late 2012 or early 2013. **DP&L** is unable to predict the financial effect of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse effect on operations.

Notice of Violation Involving Co-Owned Plants

On September 9, 2011, **DP&L** received a notice of violation from the USEPA with respect to its co-owned J.M. Stuart generating station based on a compliance evaluation inspection conducted by the USEPA and Ohio EPA in 2009. The notice alleged non-compliance by **DP&L** with certain provisions of the RCRA, the Clean Water Act NPDES permit program and the station's storm water pollution prevention plan. The notice requested that **DP&L** respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on **DP&L's** results of operations, financial condition or cash flow.

Legal and Other Matters

In February 2007, **DP&L** filed a lawsuit in the United States District Court for Southern District of Ohio against Appalachian Fuels, LLC ("Appalachian") seeking damages incurred due to Appalachian's failure to supply approximately 1.5 million tons of coal to two commonly owned plants under a coal supply agreement, of which approximately 570 thousand tons was **DP&L's** share. **DP&L** obtained replacement coal to meet its needs. Appalachian has denied liability, and is currently in federal bankruptcy proceedings in which **DP&L** is participating as an unsecured creditor. **DP&L** is unable to determine the ultimate resolution of this matter. **DP&L** has not recorded any assets relating to possible recovery of costs in this lawsuit.

In connection with **DP&L** and other utilities joining PJM in 2006, the FERC ordered utilities to eliminate certain charges to implement transitional payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, **DP&L** was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments. A hearing was held and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010 that substantially supports **DP&L's** and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. Prior to this final order being issued, **DP&L** entered into a significant number of bilateral settlement agreements with certain parties to resolve the matter, which by design will be unaffected by the final decision. On July 5, 2012, a Stipulation was executed and filed with the FERC that resolves SECA claims against BP Energy Company ("BP") and **DP&L**, AEP (and its subsidiaries) and Exelon Corporation (and its subsidiaries). On October 1, 2012, DP&L received the $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; there is no remaining balance in other deferred credits related to SECA.

Lawsuits were filed in connection with the Merger seeking, among other things, one or more of the following: to enjoin consummation of the Merger until certain conditions were met, to rescind the Merger or for rescissory damages, or to commence a sale process and/or obtain an alternative transaction or to recover an unspecified amount of other damages and costs, including attorneys' fees and expenses, or a constructive trust or an accounting from the individual defendants for benefits they allegedly obtained as a result of their alleged breach of duty. All of these lawsuits, except one, were resolved and/or dismissed prior to the March 28, 2012 filing of our Form 10-K for the fiscal year ending December 31, 2011, and were discussed in that and previous reports we filed. The last of these lawsuits was dismissed on March 29, 2012.

14. Business Segments

DPL operates through two segments consisting of the operations of two of its wholly owned subsidiaries, **DP&L** (Utility segment) and DPLER, including the results of DPLER's wholly owned subsidiary, MC Squared (Competitive Retail segment). This is how we view our business and make decisions on how to allocate resources and evaluate performance.

The Utility segment is comprised of **DP&L's** electric generation, transmission and distribution businesses which generate and sell electricity to residential, commercial, industrial and governmental customers. Electricity for the segment's 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers who are located in a 6,000 square mile area of West Central Ohio. **DP&L** also sells electricity to DPLER and any excess energy and capacity is sold into the wholesale market. **DP&L's** transmission and distribution businesses are subject to rate regulation by federal and state regulators while rates for its generation business are deemed competitive under Ohio law.

The Competitive Retail segment is comprised of the DPLER and MC Squared competitive retail electric service businesses which sell retail electric energy under contract to residential, commercial, industrial and governmental customers who have selected DPLER or MC Squared as their alternative electric supplier. The Competitive Retail segment sells electricity to approximately 175,000 customers located throughout Ohio and in Illinois. This number includes 101,000 customers in Northern Illinois of MC Squared, a Chicago-based retail electricity supplier, which was acquired by DPLER in February 2011. Due to increased competition in Ohio, since 2010 we have increased the number of employees and resources assigned to manage the Competitive Retail segment and increased its marketing to customers. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. Intercompany sales from **DP&L** to DPLER are based on fixed-price contracts for each DPLER customer; the price approximates market prices for wholesale power at the inception of each customer's contract. The Competitive Retail segment has no transmission or generation assets. The operations of the Competitive Retail segment are not subject to cost-of-service rate regulation by federal or state regulators.

Included within the "Other" column are other businesses that do not meet the GAAP requirements for disclosure as reportable segments as well as certain corporate costs which include interest expense on **DPL's** debt.

Management evaluates segment performance based on gross margin. The accounting policies of the reportable segments are the same as those described in Note 1 – Overview and Summary of Significant Accounting Policies. Intersegment sales and profits are eliminated in consolidation.

In the third quarter of 2012, **DP&L** recognized a fixed asset impairment related to generating plants of $80.8 million for reasons similar to those discussed in Note 15 Goodwill impairment. As a result of acquisition accounting, **DPL** revalued its fixed assets at fair value as of the Merger date. In accordance with FASC 360, no impairment was required at the **DPL** consolidated level. As such the **DP&L** impairment was eliminated in consolidation as reflected in the tables below.

The following table presents financial information for each of **DPL's** reportable business segments:

Successor

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
For the three months ended September 30, 2012					
Revenues from external customers	$ 313.4	$ 145.5	$ 12.8	$ -	$ 471.7
Intersegment revenues	113.4	-	0.9	(114.3)	-
Total revenues	426.8	145.5	13.7	(114.3)	471.7
Fuel	108.1	-	4.6	-	112.7
Purchased power	79.9	123.4	0.9	(113.5)	90.7
Amortization of intangibles	-	-	24.2	-	24.2
Gross margin	$ 238.8	$ 22.1	$ (16.0)	$ (0.8)	$ 244.1
Depreciation and amortization	$ 36.5	$ 0.2	$ (3.6)	$ -	$ 33.1

Goodwill impairment (Note 15)	-	-	1,850.0	-	1,850.0
Fixed asset impairment	80.8	-	-	(80.8)	-
Interest expense	10.0	0.2	21.0	(0.1)	31.1
Income tax expense (benefit)	6.5	5.9	7.8	-	20.2
Net income (loss)	(11.2)	10.0	(1,809.7)	-	(1,810.9)
Cash capital expenditures	52.2	-	0.4	-	52.6
At September 30, 2012					
Total assets	$ 3,386.6	$ 93.2	$ 714.4	$ -	$ 4,194.2
Predecessor					
For the three months ended September 30, 2011					
Revenues from external customers	$ 362.3	$ 118.6	$ 16.7	$ -	$ 497.6
Intersegment revenues	90.2	-	1.1	(91.3)	-
Total revenues	452.5	118.6	17.8	(91.3)	497.6
Fuel	124.0	-	5.0	-	129.0
Purchased power	95.6	101.4	1.5	(90.2)	108.3
Gross margin	$ 232.9	$ 17.2	$ 11.3	$ (1.1)	$ 260.3
Depreciation and amortization	$ 33.8	$ 0.1	$ 1.9	$ -	$ 35.8
Interest expense	9.3	0.1	7.6	(0.2)	16.8
Income tax expense (benefit)	26.8	4.2	(2.4)	-	28.6
Net income (loss)	63.9	7.8	(6.2)	1.6	67.1
Cash capital expenditures	49.1	-	0.8	-	49.9
At December 31, 2011					
Total assets	$ 3,538.3	$ 69.9	$ 2,529.0	$ -	$ 6,137.2

Successor

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
For the nine months ended September 30, 2012					
Revenues from external customers	$ 887.9	$ 367.5	$ 32.3	$ -	$ 1,287.7
Intersegment revenues	285.1	-	2.6	(287.7)	-
Total revenues	1,173.0	367.5	34.9	(287.7)	1,287.7
Fuel	272.3	-	6.7	-	279.0
Purchased power	234.1	315.6	1.3	(285.2)	265.8
Amortization of intangibles	-	-	71.2	-	71.2
Gross margin	$ 666.6	$ 51.9	$ (44.3)	$ (2.5)	$ 671.7
Depreciation and amortization	$ 107.3	$ 0.3	$ (12.0)	$ -	$ 95.6
Goodwill impairment (Note 15)	-	-	1,850.0	-	1,850.0
Fixed asset impairment	80.8	-	-	(80.8)	-
Interest expense	29.0	0.4	64.1	(0.4)	93.1
Income tax expense (benefit)	39.4	15.8	(14.9)	-	40.3
Net income (loss)	58.3	17.5	(1,853.1)	-	(1,777.3)
Cash capital expenditures	161.7	0.5	0.9	-	163.1
At September 30, 2012					
Total assets	$ 3,386.6	$ 93.2	$ 714.4	$ -	$ 4,194.2
Predecessor					
For the nine months ended September 30, 2011					
Revenues from external customers	$ 1,052.9	$ 314.6	$ 44.0	$ -	$ 1,411.5
Intersegment revenues	246.3	-	3.1	(249.4)	-
Total revenues	1,299.2	314.6	47.1	(249.4)	1,411.5
Fuel	311.7	-	9.2	-	320.9
Purchased power	317.8	268.6	2.6	(246.3)	342.7
Gross margin	$ 669.7	$ 46.0	$ 35.3	$ (3.1)	$ 747.9

Depreciation and amortization	$ 100.3	$ 0.2	$ 5.5	$ -	$ 106.0
Interest expense	28.7	0.2	22.7	(0.3)	51.3
Income tax expense (benefit)	69.3	14.1	(13.7)	-	69.7
Net income (loss)	147.4	19.6	(24.7)	-	142.3
Cash capital expenditures	139.9	-	1.4	-	141.3
At December 31, 2011					
Total assets	$ 3,538.3	$ 69.9	$ 2,529.0	$ -	$ 6,137.2

15. Goodwill Impairment

In connection with the acquisition of **DPL** by AES, **DPL** allocated the purchase price to goodwill for two Reporting Units, the DP&L Reporting Unit, which includes **DP&L** and other entities, and DPLER. Of the total goodwill, approximately $2.4 billion was allocated to the DP&L Reporting Unit and the remainder was allocated to DPLER. On October 5, 2012, **DP&L** filed for approval an ESP with the PUCO. Within the ESP filing, **DP&L** has agreed to request a separation of its generation assets from its transmission and distribution assets in recognition that a restructuring of **DP&L's** operations will be necessary, in compliance with Ohio law. Also, during 2012, North American natural gas prices fell significantly from the previous year exerting downward pressure on wholesale electricity prices in the Ohio power market. Falling power prices compressed wholesale margins at DP&L. Furthermore, these lower power prices have led to increased switching from **DP&L** to other CRES providers, including DPLER, who are offering retail prices lower than **DP&L's** current standard service offer. Also, several municipalities in **DP&L's** service territory have passed ordinances allowing them to become government aggregators and some municipalities have contracted with CRES providers to provide generation service to the customers located within the municipal boundaries, further contributing to the switching trend. CRES providers have also become more active in **DP&L's** service territory. In September 2012, management revised its cash flow forecasts based on these new developments and forecasted lower profitability and operating cash flows than previously prepared forecasts. These new developments have reduced **DP&L's** forecasted profitability, operating cash flows, liquidity and may impact **DPL** and **DP&L's** ability to access the capital markets and maintain their current credit ratings in the future. Collectively, in the third quarter of 2012, these events were considered an interim impairment indicator for **DPL's** goodwill at the DP&L Reporting Unit. There were no interim impairment indicators identified for the goodwill at DPLER.

We performed an interim impairment test on the $2.4 billion of goodwill at the DP&L Reporting Unit level. In the preliminary Step 1 of the goodwill impairment test, the fair value of the Reporting Unit was determined under the income approach using a discounted cash flow valuation model. The material assumptions included within the discounted cash flow valuation model were customer switching and aggregation trends, capacity price curves, energy price curves, amount of the nonbypassable charge, commodity price curves, dispatching, transition period for the conversion to a wholesale competitive bidding structure, amount of the standard service offer charge, valuation of regulatory assets and liabilities, discount rates and deferred income taxes. Further refinement to these assumptions as part of the completion of the preliminary Step 1 and Step 2 tests could have a significant impact on the enterprise value and the implied fair value of goodwill. The Reporting Unit failed the preliminary Step 1 and a preliminary Step 2 of the goodwill impairment test was performed. For the three months ended September 30, 2012, we have recognized a goodwill impairment expense of $1,850.0 million, which represents our best estimate of the impairment loss based on the latest information available and the results of the preliminary Step 1 and Step 2 tests. We estimate the final goodwill impairment expense will be in the range of $1.7 billion to $2.0 billion. In the fourth quarter of 2012, we expect to conclude the interim impairment test of goodwill and finalize the estimation of the impairment charge. We were not able to finalize the Step 1 and Step 2 tests by the filing date of this Form 10-Q due to the significant amount of work required to calculate the implied fair value of goodwill for a complex, regulated utility such as **DP&L** and the other entities in the DP&L Reporting Unit and due to the timing of the identification of the interim impairment indicator. Actual goodwill impairment loss could be significantly different from the estimated impairment loss recognized.

The goodwill associated with the **DPL** acquisition is not deductible for tax purposes. Accordingly, there is no cash tax or financial statement tax benefit related to the impairment. The Company's effective tax rates were impacted by the pretax impairment, however. The Company's effective tax rates were (1.2)% and (2.3)% for the three months and nine months ended September 30, 2012, respectively.

THE DAYTON POWER AND LIGHT COMPANY
CONDENSED STATEMENTS OF RESULTS OF OPERATIONS

$ in millions	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenues	$ 426.8	$ 452.5	$ 1,173.0	$ 1,299.2
Cost of revenues:				
Fuel	108.1	124.0	272.3	311.7
Purchased power	79.9	95.6	234.1	317.8
Total cost of revenues	188.0	219.6	506.4	629.5
Gross margin	238.8	232.9	666.6	669.7
Operating expenses:				
Operation and maintenance	103.6	80.2	298.8	266.7
Depreciation and amortization	36.5	33.8	107.3	100.3
General taxes	14.3	18.9	54.1	57.6
Fixed asset impairment	80.8	-	80.8	-
Total operating expenses	235.2	132.9	541.0	424.6
Operating income	3.6	100.0	125.6	245.1
Other income / (expense), net:				
Investment income	1.9	0.4	2.1	1.5
Interest expense	(10.0)	(9.3)	(29.0)	(28.7)
Other expense	(0.2)	(0.4)	(1.0)	(1.2)
Total other income / (expense), net	(8.3)	(9.3)	(27.9)	(28.4)
Earnings / (loss) before income tax	(4.7)	90.7	97.7	216.7
Income tax expense	6.5	26.8	39.4	69.3
Net income / (loss)	(11.2)	63.9	58.3	147.4
Dividends on preferred stock	0.2	0.2	0.6	0.6
Earnings / (loss) on common stock	$ (11.4)	$ 63.7	$ 57.7	$ 146.8

See Notes to Condensed Financial Statements.
These interim statements are unaudited.

THE DAYTON POWER AND LIGHT COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME / (LOSS)

$ in millions	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net income / (loss)	$ (11.2)	$ 63.9	$ 58.3	$ 147.4
Available-for-sale securities activity:				
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $(0.1) and $0.1, respectively, for the three month period and $(0.3) and $(1.3), respectively, for the nine month period	0.2	(0.4)	0.5	2.3
Total change in fair value of available-for-sale securities	0.2	(0.4)	0.5	2.3
Derivative activity:				
Change in derivative fair value, net of	(2.5)	1.8	(4.0)	0.7

income tax benefit / (expense) of $1.3 and $0.0, respectively, for the three month period and $2.2 and $0.8, respectively, for the nine month period				
Reclassification of earnings, net of income tax benefit / (expense) of $0.1 and $0.9, respectively for the three month period and $0.7 and $0.3, respectively for the nine month period	(0.7)	(0.5)	(3.1)	(0.5)
Total change in fair value of derivatives	(3.2)	1.3	(7.1)	0.2
Pension and postretirement activity:				
Reclassification to earnings, net of income tax benefit / (expense) of $(0.6) and $(0.1), respectively, for the three month period and $(1.7) and $0.7, respectively for the nine month period	1.0	1.0	3.0	2.6
Total change in unfunded pension obligation	1.0	1.0	3.0	2.6
Other comprehensive income / (loss)	(2.0)	1.9	(3.6)	5.1
Net comprehensive income / (loss)	$ (13.2)	$ 65.8	$ 54.7	$ 152.5

See Notes to Condensed Financial Statements.
These interim statements are unaudited.

THE DAYTON POWER AND LIGHT COMPANY
CONDENSED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
$ in millions	2012	2011
Cash flows from operating activities:		
Net income	$ 58.3	$ 147.4
Adjustments to reconcile Net income to Net cash provided by operating activities:		
Depreciation and amortization	107.3	100.3
Deferred income taxes	(3.4)	56.1
Fixed asset impairment	80.8	-
Recognition of deferred SECA revenue	(17.8)	-
Changes in certain assets and liabilities:		
Accounts receivable	13.0	26.4
Inventories	28.1	(9.0)
Prepaid taxes	0.8	(11.5)
Taxes applicable to subsequent years	56.2	47.1
Deferred regulatory costs, net	2.4	7.9
Accounts payable	(16.3)	(14.9)
Accrued taxes payable	(35.2)	(58.5)
Accrued interest payable	7.4	7.4
Pension, retiree, and other benefits	24.4	(31.7)
Unamortized investment tax credit	(1.9)	(2.1)
Other	(4.3)	29.3
Net cash provided by operating activities	299.8	294.2
Cash flows from investing activities:		
Capital expenditures	(161.7)	(139.9)
Increase in restricted cash	(5.2)	(7.4)
Other	-	1.4
Net cash from investing activities	(166.9)	(145.9)

THE DAYTON POWER AND LIGHT COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (cont.)

$ in millions	Nine Months Ended September 30, 2012	2011
Net cash from financing activities:		
Dividends paid on common stock to parent	**(145.0)**	(180.0)
Dividends paid on preferred stock	**(0.6)**	(0.6)
Retirement of long-term debt	**(0.1)**	-
Withdrawals from revolving credit facilities	**-**	50.0
Repayment of borrowing from revolving credit facilities	**-**	(50.0)
Net cash from financing activities	**(145.7)**	(180.6)
Cash and cash equivalents:		
Net change	**(12.8)**	(32.3)
Balance at beginning of period	**32.2**	54.0
Cash and cash equivalents at end of period	**$ 19.4**	$ 21.7
Supplemental cash flow information:		
Interest paid, net of amounts capitalized	**$ 22.6**	$ 22.2
Income taxes paid, net	**$ 30.3**	$ 13.9
Non-cash financing and investing activities:		
Accruals for capital expenditures	**$ 12.5**	$ 14.8
Long-term liability incurred for purchase of plant assets	**$ -**	$ 18.7

See Notes to Condensed Financial Statements.
These interim statements are unaudited.

THE DAYTON POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

$ in millions	At September 30, 2012	At December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 19.4**	$ 32.2
Restricted cash	**19.5**	14.3
Accounts receivable, net (Note 3)	**171.8**	178.5
Inventories (Note 3)	**95.1**	123.1
Taxes applicable to subsequent years	**15.7**	71.9
Regulatory assets, current (Note 4)	**18.9**	17.7
Other prepayments and current assets	**17.3**	23.2
Total current assets	**357.7**	460.9
Property, plant & equipment:		
Property, plant & equipment	**5,216.4**	5,277.9
Less: Accumulated depreciation and amortization	**(2,500.0)**	(2,568.9)
	2,716.4	2,709.0
Construction work in process	**99.0**	150.7
Total net property, plant & equipment	**2,815.4**	2,859.7
Other noncurrent assets:		
Regulatory assets, non-current (Note 4)	**181.3**	177.8
Intangible assets, net of amortization	**11.4**	6.5
Other deferred assets	**20.8**	33.4
Total other noncurrent assets	**213.5**	217.7

Total assets	$	**3,386.6**	$	3,538.3

See Notes to Condensed Financial Statements.
These interim statements are unaudited.

THE DAYTON POWER AND LIGHT COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

$ in millions		At September 30, 2012		At December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Current portion - long-term debt (Note 6)	$	**0.4**	$	0.4
Accounts payable		**74.1**		106.0
Accrued taxes		**108.7**		72.8
Accrued interest		**15.6**		7.9
Customer security deposits		**15.9**		15.8
Other current liabilities		**60.5**		46.1
Total current liabilities		**275.2**		249.0
Noncurrent liabilities:				
Long-term debt (Note 6)		**902.8**		903.0
Deferred taxes (Note 7)		**644.0**		637.7
Taxes payable		**25.5**		93.9
Regulatory liabilities, non-current (Note 4)		**117.5**		118.6
Pension, retiree and other benefits		**55.7**		47.5
Unamortized investment tax credit		**28.0**		29.9
Derivative liability		**5.2**		11.8
Other deferred credits		**43.5**		66.1
Total noncurrent liabilities		**1,822.2**		1,908.5
Redeemable preferred stock		**22.9**		22.9
Commitments and contingencies (Note 12)				
Common shareholder's equity:				
Common stock, at par value of $0.01 per share:		**0.4**		0.4
Other paid-in capital		**802.5**		803.1
Accumulated other comprehensive loss		**(38.3)**		(34.7)
Retained earnings		**501.7**		589.1
Total common shareholder's equity		**1,266.3**		1,357.9
Total liabilities and shareholder's equity	$	**3,386.6**	$	3,538.3

See Notes to Condensed Financial Statements.
These interim statements are unaudited.

Notes to Condensed Financial Statements (Unaudited)

1. Overview and Summary of Significant Accounting Policies

Description of Business

DP&L is a public utility incorporated in 1911 under the laws of Ohio. **DP&L** is engaged in the generation, transmission, distribution and sale of electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. Electricity for **DP&L**'s 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense. **DP&L** is a wholly owned subsidiary of **DPL**.

On November 28, 2011, **DP&L's** parent company **DPL** was acquired by AES in the Merger and **DPL** became an indirectly wholly owned subsidiary of AES. See Note 2 for more information.

DP&L's sales reflect the general economic conditions and seasonal weather patterns of the area. **DP&L** sells any excess energy and capacity into the wholesale market.

DP&L's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law. Accordingly, **DP&L** applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates, and regulatory liabilities when current cost recoveries in customer rates relate to expected future costs.

DP&L employed 1,443 people as of September 30, 2012. Approximately 54% of all employees are under a collective bargaining agreement which expires on October 31, 2014.

Financial Statement Presentation

DP&L does not have any subsidiaries. **DP&L** has undivided ownership interests in seven electric generating facilities and numerous transmission facilities. Operating revenues and expenses of these generating plants are included on a pro rata basis in the corresponding lines in the Condensed Consolidated Statement of Operations. See Note 5 for more information.

Certain excise taxes collected from customers have been reclassified out of operating expense and recorded as a reduction in revenues in the 2011 presentation to conform to AES' presentation of these items. These taxes are presented net within revenue. Certain immaterial amounts from prior periods have been reclassified to conform to the current reporting presentation.

These financial statements have been prepared in accordance with GAAP for interim financial statements, the instructions of Form 10-Q and Regulation S-X. Accordingly, certain information and footnote disclosures normally included in the annual financial statements prepared in accordance with GAAP have been omitted from this interim report. Therefore, our interim financial statements in this report should be read along with the annual financial statements included in our Form 10-K for the fiscal year ended December 31, 2011.

In the opinion of our management, the Condensed Financial Statements presented in this report contain all adjustments necessary to fairly state our financial condition as of September 30, 2012, our results of operations for the three and nine months ended September 30, 2012 and our cash flows for the nine months ended September 30, 2012. Unless otherwise noted, all adjustments are normal and recurring in nature. Due to various factors, including but not limited to, seasonal weather variations, the timing of outages of electric generating units, changes in economic conditions involving commodity prices and competition, and other factors, interim results for the three and nine months ended September 30, 2012 may not be indicative of our results that will be realized for the full year ending December 31, 2012.

The preparation of financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the revenues and expenses of the periods reported. Actual results could differ from these estimates. Significant items subject to such estimates and judgments include: the carrying value of property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the

valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits.

Property, Plant and Equipment

We record our ownership share of our undivided interest in jointly-held plants as an asset in property, plant and equipment. Property, plant and equipment are stated at cost. For regulated transmission and distribution property, cost includes direct labor and material, allocable overhead expenses and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of borrowed funds and equity used to finance regulated construction projects. For non-regulated property, cost also includes capitalized interest. Capitalization of AFUDC and interest ceases at either project completion or at the date specified by regulators. AFUDC and capitalized interest was $0.9 million and $1.1 million for the three months and $3.4 million and $3.5 million for the nine months ended September 30, 2012 and 2011, respectively.

For unregulated generation property, cost includes direct labor and material, allocable overhead expenses and interest capitalized during construction using the provisions of GAAP relating to the accounting for capitalized interest.

For substantially all depreciable property, when a unit of property is retired, the original cost of that property less any salvage value is charged to Accumulated depreciation and amortization.

Property is evaluated for impairment when events or changes in circumstances indicate that its carrying amount may not be recoverable.

Intangibles

Intangibles consist of emission allowances and renewable energy credits. Emission allowances are carried on a first-in, first-out (FIFO) basis for purchased emission allowances. Net gains or losses on the sale of excess emission allowances, representing the difference between the sales proceeds and the cost of emission allowances, are recorded as a component of our fuel costs and are reflected in Operating income when realized. During the nine months ended September 30, 2012 and 2011, **DP&L** had no gains from the sale of emission allowances. Emission allowances are amortized as they are used in our operations. Renewable energy credits are amortized as they are used or retired. Prior to the Merger date, emission allowances and renewable energy credits were carried as inventory. Emission allowances and renewable energy credits are now carried as intangibles in accordance with AES' policy. The amounts for 2011 have been reclassified to reflect this change in presentation.

Accounting for Taxes Collected from Customers and Remitted to Governmental Authorities

DP&L collects certain excise taxes levied by state or local governments from its customers. Prior to the Merger date, certain excise and other taxes were recorded on a gross basis. Effective on the Merger date, these taxes are accounted for on a net basis and are recorded as a reduction in Revenues for presentation in accordance with AES policy. The amounts for the three months ended September 30, 2012 and 2011 were $13.8 million and $14.3 million, respectively. The amounts for the nine months ended September 30, 2012 and 2011 were $38.5 million and $39.9 million, respectively. The 2011 amounts were reclassified to conform to this presentation.

Share-Based Compensation

We measured the cost of employee services received and paid with equity instruments based on the fair-value of such equity instrument on the grant date. This cost was recognized in results of operations over the period that employees were required to provide service. Liability awards were initially recorded based on the fair-value of equity instruments and were re-measured for the change in stock price at each subsequent reporting date until the liability was ultimately settled. The fair-value for employee share options and other similar instruments at the grant date were estimated using option-pricing models and any excess tax benefits were recognized as an addition to paid-in capital. The reduction in income taxes payable from the excess tax benefits was presented in the Condensed Statements of Cash Flows within Cash flows from financing activities. As a result of the Merger (see Note 2), vesting of all **DPL** share-based awards was accelerated as of the Merger date, and none are in existence at September 30, 2012.

Related Party Transactions

In the normal course of business, **DP&L** enters into transactions with other subsidiaries of **DPL**. The following table provides a summary of these transactions:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2012	**2011**	**2012**	**2011**
DP&L Revenues:				
Sales to DPLER *(a)*	**$ 93.3**	$ 90.2	**$ 263.1**	$ 246.3
Sales to MC Squared *(b)*	**$ 19.8**	$ -	**$ 20.1**	$ -
DP&L Operations and Maintenance Expenses:				
Premiums paid for insurance services provided by MVIC *(c)*	**$ (0.7)**	$ (0.8)	**$ (1.9)**	$ (2.4)
Expense recoveries for services provided to DPLER *(d)*	**$ 1.2**	$ 1.1	**$ 2.7**	$ 2.8

(a) ***DP&L** sells power to DPLER to satisfy the electric requirements of DPLER's retail customers. The revenue dollars associated with sales to DPLER are recorded as wholesale revenues in **DP&L**'s Financial Statements. The increase in **DP&L**'s sales to DPLER during the three and nine months ended September 30, 2012, compared to the three and nine months ended September 30, 2011, is primarily due to customers electing to switch their generation service from **DP&L** to DPLER.*

(b) ***DP&L** sells power to MC Squared to satisfy the electric requirements of DPLER's retail customers. The revenue dollars associated with sales to DPLER are recorded as wholesale revenues in **DP&L**'s Financial Statements. The increase in **DP&L**'s sales to MC Squared during the three and nine months ended September 30, 2012, compared to the three and nine months ended September 30, 2011, is due to these sales beginning in September 2012.*

(c) *MVIC, a wholly owned captive insurance subsidiary of **DPL**, provides insurance coverage to **DP&L** and other **DPL** subsidiaries for workers' compensation, general liability, property damages and directors' and officers' liability. These amounts represent insurance premiums paid by **DP&L** to MVIC.*

(d) *In the normal course of business **DP&L** incurs and records expenses on behalf of DPLER. Such expenses include but are not limited to employee-related expenses, accounting, information technology, payroll, legal and other administrative expenses. **DP&L***

*subsequently charges these expenses to DPLER at **DP&L**'s cost and credits the expense in which they were initially recorded.*

Recently Issued Accounting Standards

Offsetting Assets and Liabilities

In December 2011, the FASB issued ASU 2011-11 "Disclosures about Offsetting Assets and Liabilities" (ASU 2011-11) effective for interim and annual reporting periods beginning on or after January 1, 2013. We expect to adopt this ASU on January 1, 2013. This standard updates FASC 210, "Balance Sheet." ASU 2011-11 updates the disclosures for financial instruments and derivatives to provide more transparent information around the offsetting of assets and liabilities. Entities are required to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and/or subject to an agreement similar to a master netting agreement. We do not expect these new rules to have a material impact on our overall results of operations, financial position or cash flows.

Testing Indefinite-Lived Intangible Assets for Impairments

In July 2012, the FASB issued ASU 2012-02 "Testing Indefinite-Lived Intangible Assets for Impairment" (ASU 2012-02) effective for interim and annual impairment tests performed for fiscal years beginning after September 15, 2012. We expect to adopt this ASU on January 1, 2013. This standard updates FASC Topic 350, "Intangibles-Goodwill and Other." ASU 2012-02 permits an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired as a basis for determining whether it is necessary to perform the quantitative impairment test in accordance with FASC Subtopic 350-30. We do not expect these new rules to have a material impact on our overall results of operations, financial position or cash flows.

Recently Adopted Accounting Standards

Fair Value Disclosures

In May 2011, the FASB issued ASU 2011-04 "Fair Value Measurements" (ASU 2011-04) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 820, "Fair Value Measurements." ASU 2011-04 essentially converges US GAAP

guidance on fair value with the IFRS guidance. The ASU requires more disclosures around Level 3 inputs. It also increases reporting for financial instruments disclosed at fair value but not recorded at fair value and provides clarification of blockage factors and other premiums and discounts. These new rules did not have a material effect on our overall results of operations, financial position or cash flows.

Comprehensive Income

In June 2011, the FASB issued ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 220, "Comprehensive Income." ASU 2011-05 essentially converges US GAAP guidance on the presentation of comprehensive income with the IFRS guidance. The ASU requires the presentation of comprehensive income in one continuous financial statement or two separate but consecutive statements. Any reclassification adjustments from other comprehensive income to net income are required to be presented on the face of the Statement of Comprehensive Income. These new rules did not have a material effect on our overall results of operations, financial position or cash flows.

Derivative gross vs. net presentation – Following the acquisition of **DPL** in November 2011 by AES, **DP&L** began presenting its derivative positions on a gross basis in accordance with AES policy. This change has been reflected in the 2011 balance sheet contained in these statements.

2. Business Combination

On November 28, 2011, all of the outstanding common stock of **DP&L's** parent company, **DPL**, was acquired by AES. In accordance with FASC 805, the assets and liabilities of **DPL** were valued at their fair value at the Merger date. These adjustments were "pushed down" to **DPL's** records. These adjustments were not pushed down to **DP&L** which will continue to use its historic costs for its assets and liabilities.

3. Supplemental Financial Information

$ in millions		**At September 30, 2012**		At December 31, 2011
Accounts receivable, net:				
Unbilled revenue	**$**	**34.2**	$	49.5
Customer receivables		**89.3**		85.8
Amounts due from partners in jointly-owned plants		**16.5**		29.2

Coal sales		**4.5**		1.0
Other		**28.4**		13.9
Provision for uncollectible accounts		**(1.1)**		(0.9)
Total accounts receivable, net	$	**171.8**	$	178.5
Inventories, at average cost:				
Fuel, limestone and emission allowances	$	**53.7**	$	82.8
Plant materials and supplies		**39.5**		38.6
Other		**1.9**		1.7
Total inventories, at average cost	$	**95.1**	$	123.1

Accumulated Other Comprehensive Income / (Loss)

AOCI is included on our balance sheets within the Common shareholders' equity sections. The following table provides the components that constitute the balance sheet amounts in AOCI at September 30, 2012 and December 31, 2011 :

$ in millions		**At September 30, 2012**		At December 31, 2011
Financial Instruments	$	**1.1**	$	0.6
Cash flow hedges		**2.0**		9.0
Pension and postretirement benefits		**(41.4)**		(44.3)
Total	$	**(38.3)**	$	(34.7)

4. Regulatory Assets and Liabilities

In accordance with GAAP, regulatory assets and liabilities are recorded in the Condensed Balance Sheets for our regulated electric transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and regulatory liabilities represent current recovery of expected future costs or gains probable of recovery being reflected in future rates.

We evaluate our regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator.

Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected.

Regulatory assets and liabilities for **DP&L** are as follows:

$ in millions	**Type of Recovery (a)**	**Amortization through**		**At September 30, 2012**		At December 31, 2011
Current regulatory assets:						
TCRR, transmission, ancillary and other PJM-related costs	F	Ongoing	$	**6.3**	$	4.7
Power plant emission fees	C	Ongoing		**(0.3)**		4.8
Fuel and purchased power recovery costs	C	Ongoing		**12.9**		8.2
Total regulatory assets - current			$	**18.9**	$	17.7
Non-current regulatory assets:						
Deferred recoverable income taxes	B/C	Ongoing	$	**37.0**	$	24.1
Pension benefits	C	Ongoing		**87.1**		92.1
Unamortized loss on reacquired debt	C	Ongoing		**12.2**		13.0
Regional transmission organization costs	D	2014		**3.0**		4.1
Deferred storm costs - 2008	D			**18.7**		17.9
CCEM smart grid and advanced metering infrastructure costs	D			**6.6**		6.6
CCEM energy efficiency program	F	Ongoing		**5.9**		8.8

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costs					
Consumer education campaign	D		**3.0**		3.0
Retail settlement system costs	D		**3.1**		3.1
Other costs			**4.7**		5.1
Total regulatory assets - non-current		$	**181.3**	$	177.8
Non-current regulatory liabilities:					
Estimated costs of removal - regulated property		$	**111.6**	$	112.4
Postretirement benefits			**5.6**		6.2
Other			**0.3**		-
Total regulatory liabilities - non-current		$	**117.5**	$	118.6

(a) *B – Balance has an offsetting liability resulting in no effect on rate base.*

C – Recovery of incurred costs without a rate of return.

D – Recovery not yet determined, but is probable of occurring in future rate proceedings.

F – Recovery of incurred costs plus rate of return.

Regulatory Assets

TCRR, transmission, ancillary and other PJM-related costs represent the costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. On an annual basis, retail rates are adjusted to true-up costs with recovery in rates.

Power plant emission fees represent costs paid to the State of Ohio since 2002. As part of the fuel factor settlement agreement in November 2011, these costs are being recovered through the fuel factor.

Fuel and purchased power recovery costs represent prudently incurred fuel, purchased power, derivative, emission and other related costs which will be recovered from or returned to customers in the future through the operation of the fuel and purchased power recovery rider. The fuel and purchased power recovery rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter. **DP&L** implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. The auditor has recommended that the PUCO consider reducing **DP&L's** recovery of fuel costs by approximately $3.3 million from certain transactions. On October 4, 2012, we filed testimony on this issue and a hearing is scheduled in November 2012 before a hearing examiner. A decision is expected in the fourth quarter of 2012. As of September 30, 2012, we believe the entire amount is recoverable.

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow through items as the result of amounts previously provided to customers. This is the cumulative flow through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes will decrease over time.

Pension benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" costs of our regulated operations that for ratemaking purposes are deferred for future recovery. We 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 (OCI), 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. This regulatory asset represents the regulated portion that would otherwise be charged as a loss to OCI.

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed in prior periods. These costs are being amortized over the lives of the original issues in accordance with FERC and PUCO rules.

Regional transmission organization costs represent costs incurred to join an RTO. The recovery of these costs will be requested in a future FERC rate case.

Deferred storm costs – 2008 relate to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other major 2008 storms. On January 14, 2009, the PUCO granted **DP&L** the authority to defer these costs with a return until such time that **DP&L** seeks recovery in a future rate proceeding.

CCEM smart grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and implementation of AMI. On October 19, 2010, **DP&L** elected to withdraw its case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects **DP&L** to continue to monitor other utilities' Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that **DP&L** will, when appropriate, file new Smart Grid and/or AMI business cases in the future. We plan to file to recover these deferred costs in a future regulatory rate proceeding. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

CCEM energy efficiency program costs represent costs incurred to develop and implement various new customer programs addressing energy efficiency. These costs are being recovered through an energy efficiency rider (EER) that began July 1, 2009 and is subject to a two-year true-up for any over/under recovery of costs. On April 29, 2011, **DP&L** filed to true-up the EER which was approved by the PUCO on October 18, 2011. **DP&L** plans to make its next true-up filing on or before April 30, 2013.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation and its related rate case. **DP&L** will be seeking recovery of these costs as part of our next distribution rate case filing at the PUCO. The timing of such a filing has not yet been determined.

Retail settlement system costs represent costs to implement a retail settlement system that reconciles the energy a CRES supplier delivers to its customers and what its customers actually use. Based on case precedent in other utilities' cases, the costs are recoverable through a future **DP&L** rate proceeding.

Other costs primarily include RPM capacity, other PJM and rate case costs and alternative energy costs that are or will be recovered over various periods.

Regulatory Liabilities

Estimated costs of removal – regulated property reflect an estimate of amounts collected in customer rates for costs that are expected to be incurred in the future to remove existing transmission and distribution property from service when the property is retired.

Postretirement benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" gains related to our regulated operations that, for ratemaking purposes, are probable of being reflected in future rates. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, 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. This regulatory liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

On August 10, 2012, **DP&L** filed with the PUCO for an accounting order for permission to defer operation and maintenance costs as a result of damage caused by storms occurring during the final weekend of June 2012. The deferral request is for distribution expense incurred for these storms. The deferral would earn a return equal to the carrying cost of debt (5.86%) until these costs are recovered from customers. On October 19, 2012, DP&L amended its filing to change the method of calculating the deferral. If PUCO approval is received, **DP&L** will defer approximately $5.8 million of costs associated with these storms.

5. Ownership of Coal-fired Facilities

DP&L has undivided ownership interests in seven coal-fired electric generating facilities and numerous transmission facilities with certain other Ohio utilities. Certain expenses, primarily fuel costs for the generating stations, are allocated to the owners based on their energy usage. The remaining expenses, investments in fuel inventory, plant materials and operating supplies, and capital additions are allocated to the owners in accordance with their respective ownership interests. As of September 30, 2012, **DP&L** had $31.0 million of construction work in process at such jointly-owned facilities. **DP&L's** share of the operating cost of such facilities is included within the corresponding line in the Condensed Statements of Results of Operations and **DP&L's** share of the investment in the facilities is included within Total net property, plant and equipment in the Condensed Balance Sheets. Each joint owner provides their own financing for their share of the operations and capital expenditures of the jointly owned station.

DP&L's undivided ownership interest in such facilities as well as our wholly owned coal-fired Hutchings station at September 30, 2012, is as follows:

	DP&L Share	DP&L Investment

Jointly-owned production stations:	Ownership (%)	Summer Production Capacity (MW)	Gross Plant in Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)	SCR and FGD Equipment Installed and in Service (Yes/No)
Beckjord Unit 6	50.0	207	$ 76	$ 62	$ -	No
Conesville Unit 4	16.5	129	25	-	-	Yes
East Bend Station	31.0	186	208	135	1	Yes
Killen Station	67.0	402	628	308	4	Yes
Miami Fort Units 7 and 8	36.0	368	364	146	3	Yes
Stuart Station	35.0	808	740	290	12	Yes
Zimmer Station	28.1	365	1,097	639	3	Yes
Transmission (at varying percentages)			92	59	-	
Total		2,465	$ 3,230	$ 1,639	$ 23	
Wholly-owned production station:						
Hutchings Station	100.0	365	$ -	$ -	$ -	No

On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord station, including our jointly owned Unit 6, in December 2014. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. **DP&L** does not object to Duke's decision. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision.

We are considering options for the Hutchings station, but have not yet made a final decision. **DP&L** has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated and unavailable for service until at least June 1, 2014, if not indeterminately. In addition, **DP&L** has notified PJM that Hutchings Units 1 and 2 will be deactivated by June 1, 2015. We do not believe that any accruals are needed related to the Hutchings station. The decision to deactivate Units 1 and 2 has been made because these two units are not equipped with the advanced environmental control technologies needed to comply with the MACT standard, which was renamed MATS (Mercury Air Toxics Standard) when the rule was issued final on December 16, 2011, and the cost of compliance with the MATS standard or conversion to natural gas for these units would likely exceed the expected return. **DP&L** is still studying the option of converting two or more of Hutchings Units 3-6 to natural gas in order to comply with environmental requirements.

6. Debt Obligations

Long-term debt is as follows:

Long-term debt

$ in millions	At September 30, 2012	At December 31, 2011
First mortgage bonds maturing in October 2013 - 5.125%	$ **470.0**	$ 470.0
Pollution control series maturing in January 2028 - 4.70%	**35.3**	35.3
Pollution control series maturing in January 2034 - 4.80%	**179.1**	179.1
Pollution control series maturing in September 2036 - 4.80%	**100.0**	100.0
Pollution control series maturing in November 2040 - variable rates: 0.04% - 0.26% and 0.06% - 0.32% (a)	**100.0**	100.0
U.S. Government note maturing in February 2061 - 4.20%	**18.4**	18.5
Capital lease obligation	**0.2**	0.4
Unamortized debt discount	**(0.2)**	(0.3)
Total long-term debt	$ **902.8**	$ 903.0

(a) Range of interest rates for the nine months ended September 30, 2012 and the twelve months ended December 31, 2011, respectively.

Current portion - long-term debt

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$ in millions	At September 30, 2012	At December 31, 2011
U.S. Government note maturing in February 2061 - 4.20%	$ **0.1**	$ 0.1
Capital lease obligation	**0.3**	0.3
Total current portion - long-term debt - DPL	$ **0.4**	$ **0.4**

At September 30, 2012, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions	
Due within one year	$ 0.4
Due within two years	470.3
Due within three years	0.1
Due within four years	0.1
Due within five years	0.1
Thereafter	432.4
Total long-term debt	$ 903.4

On December 4, 2008, the OAQDA issued $100.0 million of collateralized, variable rate Revenue Refunding Bonds Series A and B due November 1, 2040. In turn, **DP&L** borrowed these funds from the OAQDA and issued corresponding First Mortgage Bonds to support repayment of the funds. The payment of principal and interest on each series of the bonds when due is backed by a standby letter of credit issued by JPMorgan Chase Bank, N.A. This letter of credit facility, which expires in December 2013, is irrevocable and has no subjective acceleration clauses. Fees associated with this letter of credit facility were not material during the three and nine months ended September 30, 2012 and 2011.

On April 20, 2010, **DP&L** entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on April 20, 2013 and provides **DP&L** with the ability to increase the size of the facility by an additional $50.0 million. **DP&L** had no outstanding borrowings under this credit facility at September 30, 2012 and December 31, 2011. Fees associated with this revolving credit facility were not material during the three and nine months ended September 30, 2012 and 2011. This facility also contains a $50.0 million letter of credit sublimit. As of September 30, 2012, **DP&L** had no outstanding letters of credit against this facility.

On March 1, 2011, **DP&L** completed the purchase of $18.7 million of electric transmission and distribution assets from the federal government that are located at the Wright-Patterson Air Force Base. **DP&L** financed the acquisition of these assets with a note payable to the federal government that is payable monthly over 50 years and bears interest at 4.2% per annum.

On August 24, 2011, **DP&L** entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a four year term expiring on August 24, 2015 and provides **DP&L** with the ability to increase the size of the facility by an additional $50.0 million. **DP&L** had no outstanding borrowings under this credit facility at September 30, 2012 and December 31, 2011. Fees associated with this revolving credit facility were not material during the three and nine months ended September 30, 2012 and 2011. This facility also contains a $50.0 million letter of credit sublimit. As of September 30, 2012, **DP&L** had no outstanding letters of credit against this facility.

Substantially all property, plant and equipment of **DP&L** is subject to the lien of the mortgage securing **DP&L's** First and Refunding Mortgage, dated October 1, 1935, with the Bank of New York Mellon as Trustee.

7. Income Taxes

The following table details the effective tax rates for the three and nine months ended September 30, 2012 and 2011.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
DP&L	**(138.3)%**	29.6%	**40.3%**	32.0%

Income tax expense for the three and nine months ended September 30, 2012 and 2011 was calculated using the estimated annual effective income tax rates of 30.7% and 33.1% for 2012 and 2011, respectively.

For the three and nine months ended September 30, 2011, management estimated the annual effective tax rate based upon its forecast of annual pre-tax income. For the three and nine months ended September 30, 2012, management estimated the annual effective tax rate based on actual pre-tax income for the period.

For the three months ended September 30, 2012, **DP&L's** current period effective rate is less than the estimated annual effective rate due to certain current period tax adjustments. These current period adjustments include a revision to the estimated annual effective rate resulting in a reduction of tax expense of $1.3 million offset by an increase in tax expense of $9.3 million due to fixed asset related deferred tax true-ups as well as the effect of estimate-to-actual income tax provision adjustments primarily related to lost Domestic Manufacturing Deductions.
For the nine months ended September 30, 2012, **DP&L's** current period effective rate is greater than the estimated annual effective rate due to certain current period tax adjustments. These current period adjustments include an increase in other estimated tax liabilities of $0.3 million as well as an increase in tax expense of $9.3 million due to fixed asset related true-ups as well as the effect of estimate-to-actual income tax provision adjustments primarily related to lost Domestic Manufacturing Deductions.
For the three and nine months ended September 30, 2012, the decrease in **DP&L's** effective tax rate compared to the same period in 2011 primarily reflects decreased pre-tax book income related to an impairment on certain fixed assets during the third quarter of 2012.

Deferred tax liabilities for **DP&L** increased by approximately $4.8 million and $6.3 million, respectively, during the three and nine months ended September 30, 2012. These increases were primarily related to depreciation offset by various purchase accounting adjustments.
The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010 that has continued through the current quarter. At this time, we do not expect the results of this examination to have a material effect on our financial statements.

8. Pension and Postretirement Benefits

DP&L sponsors a defined benefit pension plan for the vast majority of its employees.
We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. There were no contributions made during the nine months ended September 30, 2012. **DP&L** made a discretionary contribution of $40.0 million to the defined benefit plan during the nine months ended September 30, 2011.
The amounts presented in the following tables for pension include the collective bargaining plan formula, the traditional management plan formula, the cash balance plan formula and the SERP in the aggregate. The amounts presented for postretirement include both health and life insurance.
The net periodic benefit cost (income) of the pension and postretirement benefit plans for the three months ended September 30, 2012 and 2011 was:

Net Periodic Benefit Cost / (Income)	**Pension**		**Postretirement**	
$ in millions	**2012**	2011	**2012**	2011
Service cost	**$ 1.5**	$ 0.8	**$ -**	$ -
Interest cost	**4.3**	4.1	**0.2**	0.2
Expected return on assets *(a)*	**(5.7)**	(6.2)	**(0.1)**	(0.1)
Amortization of unrecognized:				
Actuarial loss / (gain)	**2.4**	1.7	**(0.2)**	(0.5)
Prior service cost	**0.7**	0.5	**0.1**	0.1
Net periodic benefit cost / (income) before adjustments	**3.2**	0.9	**-**	(0.3)
Settlement cost *(b)*	**0.5**	-	**-**	-
Net periodic benefit cost / (income)	**$ 3.7**	$ 0.9	**$ -**	$ (0.3)

(a) *For purposes of calculating the expected return on pension plan assets, under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be included in the MRVA equally over a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets for the 2012 and 2011 net periodic benefit cost was approximately $335.0 million and $316.0 million, respectively.*

(b) *The settlement cost relates to a former officer who has elected to receive a lump sum distribution in 2012 from the Supplemental Executive Retirement Plan.*

The net periodic benefit cost (income) of the pension and postretirement benefit plans for the nine months ended September 30, 2012 and 2011 was:

Net Periodic Benefit Cost / (Income)	**Pension**		**Postretirement**	
$ in millions	**2012**	2011	**2012**	2011
Service cost	**$ 4.6**	$ 3.7	**$ 0.1**	$ 0.1
Interest cost	**12.9**	12.7	**0.6**	0.7
Expected return on assets *(a)*	**(17.0)**	(18.4)	**(0.2)**	(0.2)
Amortization of unrecognized:				
Actuarial loss / (gain)	**7.1**	6.2	**(0.7)**	(0.9)
Prior service cost	**2.2**	1.6	**0.1**	0.1
Net periodic benefit cost / (income) before adjustments	**9.8**	5.8	**(0.1)**	(0.2)
Settlement cost *(b)*	**0.5**	-	**-**	-
Net periodic benefit cost / (income)	**$ 10.3**	$ 5.8	**$ (0.1)**	$ (0.2)

(a) *For purposes of calculating the expected return on pension plan assets, under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be included in the MRVA equally over a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets for the 2012 and 2011 net periodic benefit cost was approximately $335.0 million and $316.0 million, respectively.*

(b) *The settlement cost relates to a former officer who has elected to receive a lump sum distribution in 2012 from the Supplemental Executive Retirement Plan.*

Benefit payments, which reflect future service, are expected to be paid as follows:

Estimated Future Benefit Payments and Medicare Part D Reimbursements

$ in millions	Pension	Postretirement
2012	$ 5.8	$ 0.6
2013	22.7	2.3
2014	23.2	2.2
2015	23.8	2.0
2016	24.0	1.9
2017 - 2021	124.4	7.5

9. Fair Value Measurements

The fair values of our financial instruments are based on published sources for pricing when possible. We rely on valuation models only when no other method is available to us. The value of our financial instruments represents our best estimates of fair value, which may not be the value realized in the future. The table below presents the fair value and cost of our non-derivative instruments at September 30, 2012 and December 31, 2011. See also Note 10 for the fair values of our derivative instruments.

	At September 30, 2012		At December 31, 2011	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
Assets				
Money Market Funds	**$ 0.2**	**$ 0.2**	$ 0.2	$ 0.2
Equity Securities	**3.9**	**5.2**	3.9	4.4
Debt Securities	**5.0**	**5.5**	5.0	5.5
Multi-Strategy Fund	**0.3**	**0.3**	0.3	0.2
Total Assets	**$ 9.4**	**$ 11.2**	$ 9.4	$ 10.3
Liabilities				
Debt	**$ 903.2**	**$ 934.5**	$ 903.4	$ 934.5

Debt

The fair value of debt is based on current public market prices for disclosure purposes only. Unrealized gains or losses are not recognized in the financial statements because debt is presented at amortized cost in the financial statements. The debt amounts include the current portion payable in the next twelve months and have maturities that range from 2013 to 2061.

Master Trust Assets

DP&L established a Master Trust to hold assets that could be used for the benefit of employees participating in employee benefit plans and these assets are not used for general operating purposes. These assets are primarily comprised of open-ended mutual funds which are valued using the net asset value per unit. These investments are recorded at fair value within Other assets on the balance sheets and classified as available for sale. Any unrealized gains or losses are recorded in AOCI until the securities are sold.

DP&L had $1.7 million ($1.1 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at September 30, 2012 and $1.0 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2011.

Due to the liquidation of the **DPL** common stock held in the Master Trust, there is sufficient cash to cover the next twelve months of benefits payable to employees covered under the benefit plans. Therefore, no unrealized gains or losses are expected to be transferred to earnings since we will not need to sell any investments in the next twelve months.

Net Asset Value (NAV) per Unit

The following table discloses the fair value and redemption frequency for those assets whose fair value is estimated using the NAV per unit as of September 30, 2012. These assets are part of the Master Trust. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. At September 30, 2012, **DP&L** did not have any investments for sale at a price different from the NAV per unit.

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	**Fair Value at September 30, 2012**	Fair Value at December 31, 2011	Unfunded Commitments
Equity Securities (a)	$ **5.2**	$ 4.4	$ -
Debt Securities (b)	**5.5**	5.5	-
Multi-Strategy Fund (c)	**0.3**	0.2	-
Total	$ **11.0**	$ 10.1	$ -

(a) *This category includes investments in hedge funds representing an S&P 500 index and the Morgan Stanley Capital International (MSCI) U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current net asset value per unit.*

(b) *This category includes investments in U.S. Treasury obligations and U.S. investment grade bonds. Investments in this category can be redeemed immediately at the current net asset value per unit.*

(c) *This category includes a mix of actively managed funds holding investments in stocks, bonds and short-term investments in a mix of actively managed funds. Investments in this category can be redeemed immediately at the current net asset value per unit.*

Fair Value Hierarchy

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy requires an entity to maximize

the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. These inputs are then categorized as Level 1 (quoted prices in active markets for identical assets or liabilities); Level 2 (observable inputs such as quoted prices for similar assets or liabilities or quoted prices in markets that are not active); or Level 3 (unobservable inputs).

Valuations of assets and liabilities reflect the value of the instrument including the values associated with counterparty risk. We include our own credit risk and our counterparty's credit risk in our calculation of fair value using global average default rates based on an annual study conducted by a large rating agency.

We transferred a money market account to Level 1 from Level 2 of the fair value hierarchy, as it was determined that this fund is a cash equivalent where quoted prices are generally equal to par value.

The fair value of assets and liabilities at September 30, 2012 and December 31, 2011 measured on a recurring basis and the respective category within the fair value hierarchy for **DP&L** was determined as follows:

Assets and Liabilities Measured at Fair Value on a Recurring Basis

$ in millions	Fair Value at September 30, 2012	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Unobservable Inputs
Assets				
Master Trust Assets				
Money Market Funds	$ 0.2	$ 0.2	$ -	$ -
Equity Securities	5.2	-	5.2	-
Debt Securities	5.5	-	5.5	-
Multi-Strategy Fund	0.3	-	0.3	-
Total Master Trust Assets	11.2	0.2	11.0	-
Derivative Assets				
FTRs	0.1	-	-	0.1
Heating Oil Futures	0.4	0.4	-	-
Forward Power Contracts	5.0	-	5.0	-
Total Derivative Assets	5.5	0.4	5.0	0.1
Total Assets	$ 16.7	$ 0.6	$ 16.0	$ 0.1
Liabilities				
Derivative Liabilities				
FTRs	$ (0.1)	$ -	$ -	$ (0.1)
Forward NYMEX Coal Contracts	(1.1)	-	(1.1)	-
Forward Power Contracts	(18.6)	-	(18.6)	-
Total Derivative Liabilities	(19.8)	-	(19.7)	(0.1)
Long-term Debt	(934.5)	-	(915.5)	(19.0)
Total Liabilities	$ (954.3)	$ -	$ (935.2)	$ (19.1)

Assets and Liabilities Measured at Fair Value on a Recurring Basis

$ in millions	Fair Value as of December 31, 2011	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Unobservable Inputs
Assets				
Master Trust Assets				
Money Market Funds	$ 0.2	$ -	$ 0.2	$ -
Equity Securities	4.4	-	4.4	-
Debt Securities	5.5	-	5.5	-
Multi-Strategy Fund	0.2	-	0.2	-
Total Master Trust Assets	10.3	-	10.3	-
Derivative Assets				
FTRs	0.1	-	0.1	-
Heating Oil Futures	1.8	1.8	-	-
Forward Power Contracts	4.1	-	17.3	-
Total Derivative Assets	6.0	1.8	17.4	-
Total Assets	$ 16.3	$ 1.8	$ 27.7	$ -
Liabilities				
Derivative Liabilities				
Forward NYMEX Coal Contracts	$ (14.5)	$ -	$ (14.5)	$ -

Forward Power Contracts	(5.0)	-	(13.3)	-
Total Derivative Liabilities	(19.5)	-	(27.8)	-
Total Liabilities	$ (19.5)	$ -	$ (27.8)	$ -

We use the market approach to value our financial instruments. Level 1 inputs are used for derivative contracts such as heating oil futures and for money market accounts that are considered cash equivalents. The fair value is determined by reference to quoted market prices and other relevant information generated by market transactions. Level 2 inputs are used to value derivatives such as forward power contracts and forward NYMEX-quality coal contracts (which are traded on the OTC market but which are valued using prices on the NYMEX for similar contracts on the OTC market). Other Level 2 assets include: open-ended mutual funds that are in the Master Trust, which are valued using the end of day NAV per unit; and interest rate hedges, which use observable inputs to populate a pricing model. Financial transmission rights are considered a Level 3 input beginning April 1, 2012 because the monthly auctions are considered inactive.

Our Level 3 inputs are immaterial to our derivative balances as a whole and as such no further disclosures are presented.

Our debt is fair valued for disclosure purposes only and most of the fair values are determined using quoted market prices in inactive markets. These fair value inputs are considered Level 2 in the fair value hierarchy. Our long-term leases and the WPAFB loan are not publicly traded. Fair value is assumed to equal carrying value. These fair value inputs are considered Level 3 in the fair value hierarchy as there are no observable inputs. Additional Level 3 disclosures were not presented since debt is not recorded at fair value.

Approximately 99% of the inputs to the fair value of our derivative instruments are from quoted market prices for **DP&L**.

Non-recurring Fair Value Measurements

We use the cost approach to determine the fair value of our AROs which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. Additions to AROs were not material during the nine months ended September 30, 2012 and 2011.

10. Derivative Instruments and Hedging Activities

In the normal course of business, **DP&L** enters into various financial instruments, including derivative financial instruments. We use derivatives principally to manage the risk of changes in market prices for commodities and interest rate risk associated with our long-term debt. The derivatives that we use to economically hedge these risks are governed by our risk management policies for forward and futures contracts. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The objective of the hedging program is to mitigate financial risks while ensuring that we have adequate resources to meet our requirements. We monitor and value derivative positions monthly as part of our risk management processes. We use published sources for pricing, when possible, to mark positions to market. All of our derivative instruments are used for risk management purposes and are designated as cash flow hedges or marked to market each reporting period.

At September 30, 2012, **DP&L** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	11.1	-	11.1
Heating Oil Futures	Mark to Market	Gallons	1,932.0	-	1,932.0
Forward Power Contracts	Cash Flow Hedge	MWh	886.2	(3,194.1)	(2,307.9)
Forward Power Contracts	Mark to Market	MWh	2,366.9	(3,955.6)	(1,588.7)
NYMEX-quality Coal Contracts*	Mark to Market	Tons	46.5	-	46.5

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

At December 31, 2011, **DP&L** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	7.1	(0.7)	6.4
Heating Oil Futures	Mark to Market	Gallons	2,772.0	-	2,772.0
Forward Power Contracts	Cash Flow Hedge	MWh	886.2	(341.6)	544.6
Forward Power Contracts	Mark to Market	MWh	525.1	(525.1)	-

NYMEX-quality Coal Contracts*	Mark to Market	Tons	2,015.0	-	2,015.0

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

Cash Flow Hedges

As part of our risk management processes, we identify the relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking various hedge transactions. The fair value of cash flow hedges as determined by observable market prices available as of the balance sheet dates and will continue to fluctuate with changes in market prices up to contract expiration. The

effective portion of the hedging transaction is recognized in AOCI and transferred to earnings using specific identification of each contract when the forecasted hedged transaction takes place or when the forecasted hedged transaction is probable of not occurring. The ineffective portion of the cash flow hedge is recognized in earnings in the current period. All risk components were taken into account to determine the hedge effectiveness of the cash flow hedges.

We enter into forward power contracts to manage commodity price risk exposure related to our generation of electricity. We do not hedge all commodity price risk. We reclassify gains and losses on forward power contracts from AOCI into earnings in those periods in which the contracts settle.

The following table provides information for **DP&L** concerning gains or losses recognized in AOCI for the cash flow hedges for the three months ended September 30, 2012 and 2011:

	Three Months Ended September 30, 2012		Three Months Ended September 30, 2011	
$ in millions (net of tax)	Power	Interest Rate Hedge	Power	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	**$ (3.4)**	**$ 8.6**	$ (1.5)	$ 11.0
Net gains / (losses) associated with current period hedging transactions	**(2.5)**	**(0.6)**	1.8	-
Net gains reclassified to earnings				
Interest Expense	-	-	-	(0.6)
Revenues	-	-	0.1	-
Purchased Power	**(0.1)**	-	-	-
Ending accumulated derivative gain / (loss) in AOCI	**$ (6.0)**	**$ 8.0**	$ 0.4	$ 10.4
Net gains / (losses) associated with the ineffective portion of the hedging transaction				
Interest Expense	**$ -**	**$ -**		
Revenues	**$ -**	**$ -**		
Purchased Power	**$ -**	**$ -**		
Portion expected to be reclassified to earnings in the next twelve months*	**$ (6.9)**	**$ (2.4)**		
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**27**	**-**		

*The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

The following table provides information for **DP&L** concerning gains or losses recognized in AOCI for the cash flow hedges for the nine months ended September 30, 2012 and 2011:

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
$ in millions (net of tax)	Power	Interest Rate Hedge	Power	Interest Rate Hedge

Beginning accumulated derivative gain / (loss) in AOCI	**$ (0.7)**	**$ 9.8**	$ (1.8)	$ 12.3
Net gains / (losses) associated with current period hedging transactions	**(4.0)**	**-**	0.8	-
Net gains reclassified to earnings				
Interest Expense	**-**	**(1.8)**	-	(1.9)
Revenues	**0.1**	**-**	0.8	-
Purchased Power	**(1.4)**	**-**	0.6	-
Ending accumulated derivative gain / (loss) in AOCI	**$ (6.0)**	**$ 8.0**	$ 0.4	$ 10.4
Net gains / (losses) associated with the ineffective portion of the hedging transaction				
Interest Expense	**$ -**	**$ -**		
Revenues	**$ -**	**$ -**		
Purchased Power	**$ -**	**$ -**		
Portion expected to be reclassified to earnings in the next twelve months*	**$ (6.9)**	**$ (2.4)**		
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**27**	**-**		

*The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

The following tables show the fair value and balance sheet classification of **DP&L's** derivative instruments designated as hedging instruments at September 30, 2012 and December 31, 2011:

Fair Values of Derivative Instruments Designated as Hedging Instruments at September 30, 2012

$ in millions	Fair Value	Balance Sheet Location
Short-term Derivative Positions		
Forward Power Contracts in an Asset Position	**$ 0.4**	Other prepayments and current assets
Forward Power Contracts in a Liability Position	**(7.3)**	Other current liabilities
Total Short-term Cash Flow Hedges	**(6.9)**	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	**0.7**	Other deferred assets
Forward Power Contracts in a Liability Position	**(3.0)**	Other deferred credits
Total Long-term Cash Flow Hedges	**(2.3)**	
Total Cash Flow Hedges	**$ (9.2)**	

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2011

$ in millions	Fair Value	Balance Sheet Location
Short-term Derivative Positions		
Forward Power Contracts in an Asset Position	$ 1.5	Other prepayments and current assets
Forward Power Contracts in a Liability Position	(0.2)	Other current liabilities
Total Short-term Cash Flow Hedges	1.3	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	0.1	Other deferred assets
Forward Power Contracts in a Liability Position	(2.6)	Other deferred credits
Total Long-term Cash Flow Hedges	(2.5)	
Total Cash Flow Hedges	$ (1.2)	

Mark to Market Accounting

Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for hedge accounting or the normal purchases and sales exceptions under FASC 815. Accordingly, such contracts are recorded at fair value with changes in the fair value charged or credited to the statements of results of operations in the period in which the change occurred. This is commonly referred to as "MTM accounting."

Contracts we enter into as part of our risk management program may be settled financially, by physical delivery or net settled with the counterparty. We mark to market FTRs, heating oil futures, forward NYMEX-quality coal contracts and certain forward power contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided under GAAP. Derivative contracts that have been designated as normal purchases or normal sales under GAAP are not subject to MTM accounting treatment and are recognized in the statements of results of operations on an accrual basis.

Regulatory Assets and Liabilities

In accordance with regulatory accounting under GAAP, a cost that is probable of recovery in future rates should be deferred as a regulatory asset and a gain that is probable of being returned to customers should be deferred as a regulatory liability. Portions of the derivative contracts that are marked to market each reporting period and are related to the retail portion of **DP&L's** load requirements are included as part of the fuel and purchased power recovery rider approved by the PUCO which began January 1, 2010. Therefore, the Ohio retail customers' portion of the heating oil futures and the NYMEX-quality coal contracts are deferred as a regulatory asset or liability until the contracts settle. If these unrealized gains and losses are no longer deemed to be probable of recovery through our rates, they will be reclassified into earnings in the period such determination is made.

The following tables show the amount and classification within the statements of results of operations or balance sheets of the gains and losses on **DP&L's** derivatives not designated as hedging instruments for the three and nine months ended September 30, 2012 and 2011:

For the three months ended September 30, 2012

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ **15.5**	$ **-**	$ **0.1**	$ **(5.5)**	$ **10.1**
Realized gain / (loss)	**(12.8)**	**0.5**	**0.1**	**4.2**	**(8.0)**
Total	$ **2.7**	$ **0.5**	$ **0.2**	$ **(1.3)**	$ **2.1**
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ **4.7**	$ **-**	$ **-**	$ **-**	$ **4.7**
Regulatory (asset) / liability	**1.2**	**(0.1)**	**-**	**-**	**1.1**
Recorded in Income Statement: gain / (loss)					
Revenue	**-**	**-**	**-**	**0.3**	**0.3**
Purchased Power	**-**	**-**	**0.2**	**(1.6)**	**(1.4)**
Fuel	**(3.2)**	**0.5**	**-**	**-**	**(2.7)**
O&M	**-**	**0.1**	**-**	**-**	**0.1**
Total	$ **2.7**	$ **0.5**	$ **0.2**	$ **(1.3)**	$ **2.1**

For the three months ended September 30, 2011

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ (27.9)	$ (1.6)	$ (0.1)	$ 0.3	$ (29.3)
Realized gain / (loss)	4.3	0.5	-	(0.3)	4.5
Total	$ (23.6)	$ (1.1)	$ (0.1)	$ -	$ (24.8)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ (13.8)	$ -	$ -	$ -	$ (13.8)
Regulatory (asset) / liability	(4.0)	(0.6)	-	-	(4.6)
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(0.1)	(0.1)
Purchased Power	-	-	(0.1)	0.1	-
Fuel	(5.8)	(0.5)	-	-	(6.3)
O&M	-	-	-	-	-
Total	$ (23.6)	$ (1.1)	$ (0.1)	$ -	$ (24.8)

For the nine months ended September 30, 2012

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	**$ 13.4**	**$ (1.5)**	**$ (0.1)**	**$ (4.6)**	**$ 7.2**
Realized gain / (loss)	**(27.2)**	**1.9**	**0.5**	**4.2**	**(20.6)**
Total	**$ (13.8)**	**$ 0.4**	**$ 0.4**	**$ (0.4)**	**$ (13.4)**
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	**$ 3.5**	**$ -**	**$ -**	**$ -**	**$ 3.5**
Regulatory (asset) / liability	**0.9**	**(0.6)**	**-**	**-**	**0.3**
Recorded in Income Statement: gain / (loss)					
Revenue	**-**	**-**	**-**	**2.0**	**2.0**
Purchased Power	**-**	**-**	**0.4**	**(2.4)**	**(2.0)**
Fuel	**(18.2)**	**0.8**	**-**	**-**	**(17.4)**
O&M	**-**	**0.2**	**-**	**-**	**0.2**
Total	**$ (13.8)**	**$ 0.4**	**$ 0.4**	**$ (0.4)**	**$ (13.4)**

	For the nine months ended September 30, 2011				
$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ (41.6)	$ -	$ (0.1)	$ -	$ (41.7)
Realized gain / (loss)	8.1	1.5	(0.6)	(0.8)	8.2
Total	$ (33.5)	$ 1.5	$ (0.7)	$ (0.8)	$ (33.5)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ (21.2)	$ -	$ -	$ -	$ (21.2)
Regulatory (asset) / liability	(5.9)	0.1	-	-	(5.8)
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(0.2)	(0.2)
Purchased Power	-	-	(0.7)	(0.6)	(1.3)
Fuel	(6.4)	1.3	-	-	(5.1)
O&M	-	0.1	-	-	0.1
Total	$ (33.5)	$ 1.5	$ (0.7)	$ (0.8)	$ (33.5)

The following table shows the fair value and balance sheet classification of **DP&L's** derivative instruments not designated as hedging instruments at September 30, 2012:

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at September 30, 2012

$ in millions	Fair Value	Balance Sheet Location
Short-term Derivative Positions		
FTRs in an Asset Position	**$ 0.1**	Other prepayments and current assets
FTRs in a Liability Position	**(0.1)**	Other current liabilities
Forward Power Contracts in an Asset Position	**3.0**	Other prepayments and current assets
Forward Power Contracts in a Liability Position	**(6.1)**	Other current liabilities
NYMEX-quality Coal Forwards in a Liability Position	**(1.1)**	Other current liabilities
Heating Oil Futures in an Asset Position	**0.3**	Other prepayments and current assets
Total Short-term Derivative MTM Positions	**(3.9)**	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	**0.9**	Other deferred assets
Forward Power Contracts in a Liability Position	**(2.2)**	Other deferred credits
NYMEX-quality Coal Forwards in a Liability Position	-	Other deferred credits
Heating Oil Futures in an Asset Position	**0.1**	Other deferred assets
Total Long-term Derivative MTM Positions	**(1.2)**	
Net MTM Position	**$ (5.1)**	

The following table shows the fair value and balance sheet classification of **DP&L's** derivative instruments not designated as hedging instruments at December 31, 2011:

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at December 31, 2011

$ in millions	Fair Value	Balance Sheet Location
Short-term Derivative Positions		
FTRs in an Asset Position	$ 0.1	Other prepayments and current assets
Forward Power Contracts in an Asset Position	1.0	Other prepayments and current assets
Forward Power Contracts in a Liability Position	(0.9)	Other current liabilities
NYMEX-quality Coal Forwards in a Liability Position	(8.3)	Other current liabilities
Heating Oil Futures in an Asset Position	1.8	Other prepayments and current assets
Total Short-term Derivative MTM Positions	(6.3)	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	1.5	Other deferred assets
Forward Power Contracts in a Liability Position	(1.3)	Other deferred credits
NYMEX-quality Coal Forwards in a Liability Position	(6.2)	Other deferred credits
Total Long-term Derivative MTM Positions	(6.0)	
Net MTM Position	$ (12.3)	

Certain of our OTC commodity derivative contracts are under master netting agreements that contain provisions that require our debt to maintain an investment grade credit rating from credit rating agencies. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization of the MTM loss. The changes in our credit ratings in April 2011 have not triggered the provisions discussed above; however, there is a possibility of further downgrades related to the Merger with AES that could trigger such provisions.

The aggregate fair value of **DP&L's** commodity derivative instruments that are in a MTM loss position at September 30, 2012 is $19.8 million. This amount is offset by $10.2 million of collateral posted directly with third parties and in a broker margin account which offsets our loss positions on the forward contracts. This liability position is further offset by the asset position of counterparties with master netting agreements of $4.4 million. If our counterparties were to call for collateral, **DP&L** could be required to post collateral for the remaining $5.2 million.

11. Shareholder's Equity

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at September 30, 2012. All common shares are held by **DP&L's** parent, **DPL**.

As part of the PUCO's approval of the Merger, **DP&L** agreed to maintain a capital structure that includes an equity ratio of at least 50 percent and not to have a negative retained earnings balance.

At the October 29, 2012 meeting of **DP&L's** Board of Directors, the following dividends were approved:

- Preferred Stock – payable December 3, 2012 to stockholders of record at the close of business on November 15, 2012 totaling $0.2 million.

- Common Stock – $75.0 million payable at any time through December 31, 2012 to the stockholder of record at the close of business on October 31, 2012.
-

12. Contractual Obligations, Commercial Commitments and Contingencies

DP&L – Equity Ownership Interest

DP&L owns a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. As of September 30, 2012, **DP&L** could be responsible for the repayment of 4.9%, or $78.8 million, of a $1,607.8 million debt obligation that features maturities from 2013 to 2040. This would only happen if this electric generation company defaulted on its debt payments. As of September 30, 2012, we have no knowledge of such a default.

Commercial Commitments and Contractual Obligations

There have been no material changes, outside the ordinary course of business, to our commercial commitments and to the information disclosed in the contractual obligations table in our Form 10-K for the fiscal year ended December 31, 2011.

Contingencies
In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our Condensed Financial Statements, as prescribed by GAAP, are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims, tax examinations and other matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our Condensed Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of September 30, 2012, cannot be reasonably determined.
Environmental Matters
DP&L's facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. As well as imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at these facilities to comply, or to determine compliance, with such regulations. We record liabilities for losses that are probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. We have estimated liabilities of approximately $4.0 million for environmental matters. We evaluate the potential liability related to probable losses quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material adverse effect on our results of operations, financial condition or cash flows.
We have several pending environmental matters associated with our power plants. Some of these matters could have material adverse impacts on our business and on the operation of the power plants; especially the plants that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired power plants that do not have this equipment installed. **DP&L** owns 100% of the Hutchings station and a 50% interest in Beckjord Unit 6.
On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord station, including our jointly owned Unit 6, in December 2014. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision.
We are considering options for the Hutchings station, but have not yet made a final decision. **DP&L** has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated and unavailable for service until at least June 1, 2014, if ever. In addition, **DP&L** has notified PJM that Hutchings Units 1 and 2 will be deactivated by June 1, 2015. We do not believe that any accruals are needed related to the Hutchings station.

Environmental Matters Related to Air Quality
Clean Air Act Compliance
In 1990, the federal government amended the CAA to further regulate air pollution. Under the CAA, the USEPA sets limits on, among other things, how much of certain designated pollutants can be in the ambient air anywhere in the United States. The CAA allows individual states to have stronger pollution controls than those set under the CAA, but states are not allowed to have weaker pollution controls than those set for the whole country. The CAA has a material effect on our operations and such effects are detailed below with respect to certain programs under the CAA.
Cross-State Air Pollution Rule
The USEPA promulgated the "Clean Air Interstate Rule" (CAIR) on March 10, 2005, which required allowance surrender for SO_2 and NOx emissions from existing power plants located in 28 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase was to begin in 2009 and 2010 for NOx and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions was to begin in 2015. To implement the required emission reductions for this rule, the states were to establish emission allowance based "cap-and-trade" programs. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the USEPA.
In response to the D.C. Circuit's opinion, on July 7, 2011, the USEPA issued a final rule titled "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States," which is now referred to as the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, CSAPR would have required significant reductions in SO_2 and NOx emissions from covered sources, such as power plants. Once fully implemented in 2014, the rule would require additional SO_2 emission reductions of 73% and additional NOx

reductions of 54% from 2005 levels. Many states, utilities and other affected parties filed petitions for review, challenging the CSAPR before the U.S. Court of Appeals for the District of Columbia. A large subset of the Petitioners also sought a stay of the CSAPR. On December 30, 2011, the D.C. Circuit granted a stay of the CSAPR and directed the USEPA to continue administering CAIR. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that USEPA overstepped its regulatory authority by requiring states to make reductions beyond the levels required in the CAA and failed to provide states an initial opportunity to adopt their own measures for achieving federal compliance. As a result of this ruling, the surviving provisions of CAIR will continue to serve as the governing program until USEPA takes further action or the U.S. Congress intervenes. Assuming that USEPA constructs a replacement interstate transport rule addressing the D.C. Circuit Court's ruling, it will likely take three years or more before companies would be required to comply with a replacement rule. At this time, it is not possible to predict the details of such a replacement transport rule or what impacts it may have on our financial condition, results of operations or cash flows. On October 5, 2012, USEPA, several states and cities, as well as environmental and health organizations, filed petitions with the D.C. Circuit Court requesting a rehearing by all of the judges of the D.C. Circuit Court of the case pursuant to which the three-judge panel ruled that CSAPR be vacated. As of November 6, 2012, the D.C. Circuit Court had not ruled on USEPA's petition for rehearing. We cannot predict whether the D.C. Circuit Court will grant a rehearing or, if a rehearing is granted, whether CSAPR will be ultimately reinstated and implemented in its current form or a modified form. If CSAPR were to be reinstated in its current form, we do not expect any material capital costs for **DP&L's** plants, assuming Beckjord 6 and Hutchings generating stations will not operate on coal in 2015 due to implementation of the Mercury and Air Toxics Standards. Because we cannot predict the final outcome of the CSAPR rulemaking, we cannot predict its financial impact on **DP&L's** operations.

Mercury and Other Hazardous Air Pollutants

On May 3, 2011, the USEPA published proposed Maximum Achievable Control Technology (MACT) standards for coal- and oil-fired electric generating units. The standards include new requirements for emissions of mercury and a number of other heavy metals. The USEPA Administrator signed the final rule, now called MATS (Mercury and Air Toxics Standards), on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Affected electric generating units (EGUs) will have to come into compliance with the new requirements by April 16, 2015, but may be granted an additional year contingent on Ohio EPA approval. **DP&L** is evaluating the costs that may be incurred to comply with the new requirement; however, MATS is expected to have a material adverse effect on our uncontrolled units.

On April 29, 2010, the USEPA issued a proposed rule that would reduce emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers, and process heaters at major and area source facilities. The final rule was published in the Federal Register on March 21, 2011. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulations contain emissions limitations, operating limitations and other requirements. In December 2011, the USEPA proposed additional changes to this rule and solicited comments. Compliance costs are not expected to be material to **DP&L's** operations.

On May 3, 2010, the USEPA finalized the "National Emissions Standards for Hazardous Air Pollutants" for compression ignition (CI) reciprocating internal combustion engines (RICE). The units affected at **DP&L** are 18 diesel electric generating engines and eight emergency "black start" engines. The existing CI RICE units must comply by May 3, 2013. The regulations contain emissions limitations, operating limitations and other requirements. Compliance costs for **DP&L's** operations are not expected to be material.

Carbon and Other Greenhouse Gas Emissions

In response to a U.S. Supreme Court decision that the USEPA has the authority to regulate CO_2 emissions from motor vehicles, the USEPA made a finding that CO_2 and certain other GHGs are pollutants under the CAA. Subsequently, under the CAA, USEPA determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This finding became effective in January 2010. Numerous affected parties have petitioned the USEPA Administrator to reconsider this decision. On April 1, 2010, USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under USEPA's view, this is the final action that renders CO_2 and other GHGs "regulated air pollutants" under the CAA.

Under USEPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the USEPA began regulating GHG emissions from certain stationary sources in January 2011. The Tailoring Rule sets forth criteria for determining which facilities are required to obtain permits for their GHG emissions pursuant to the CAA Prevention of Significant Deterioration and Title V operating permit programs. Under the Tailoring Rule, permitting requirements are being phased in through successive steps that may expand the scope of covered sources over time. The USEPA has issued guidance on what the best available control technology entails for the control of GHGs and individual states are required to determine what controls are required for facilities on a case-by-case basis. The ultimate impact of the Tailoring Rule to **DP&L** cannot be determined at this time, but the cost of compliance could be material.

On April 13, 2012, the USEPA published its proposed GHG standards for new electric generating units (EGUs) under CAA subsection 111(b), which would require certain new EGUs to meet a standard of 1,000 pounds of CO_2 per megawatt-hour, a standard based on the emissions limitations achievable through natural gas combined cycle generation. The proposal anticipates that affected coal-fired units would need to install carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. Furthermore, the USEPA may propose and promulgate guidelines for states to address GHG standards for existing EGUs under CAA subsection 111(d). These latter rules may focus on energy efficiency improvements at power plants. We cannot predict the effect of these standards, if any, on **DP&L's** operations.

Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 16 million tons annually. Further GHG legislation or regulation finalized at a future date could have a significant effect on **DP&L's** operations and costs, which could adversely affect our net income, cash flows and financial condition. However, due to the uncertainty associated with such legislation or regulation, we cannot predict the final outcome or the financial impact that such legislation or regulation may have on **DP&L**.

On September 22, 2009, the USEPA issued a final rule for mandatory reporting of GHGs from large sources that emit 25,000 metric tons per year or more of GHGs, including EGUs. **DP&L** has submitted to USEPA GHG emission reports for 2011 and 2010. While this reporting rule will guide development of policies and programs to reduce emissions, **DP&L** does not anticipate that the reporting rule will itself result in any significant cost or other effect on current operations.

Litigation, Notices of Violation and Other Matters Related to Air Quality

Litigation Involving Co-Owned Plants

On June 20, 2011, the U.S. Supreme Court ruled that the USEPA's regulation of GHGs under the CAA displaced any right that plaintiffs may have had to seek similar regulation through federal common law litigation

in the court system. Although we are not named as a party to these lawsuits, **DP&L** is a co-owner of coal-fired plants with Duke Energy and AEP (or their subsidiaries) that could have been affected by the outcome of these lawsuits or similar suits that may have been filed against other electric power companies, including **DP&L**. Because the issue was not squarely before it, the U.S. Supreme Court did not rule against the portion of plaintiffs' original suits that sought relief under state law.

As a result of a 2008 consent decree entered into with the Sierra Club and approved by the U.S. District Court for the Southern District of Ohio, **DP&L** and the other owners of the J.M. Stuart generating station are subject to certain specified emission targets related to NOx, SO_2 and particulate matter. The consent decree also includes commitments for energy efficiency and renewable energy activities. An amendment to the consent decree was entered into and approved in 2010 to clarify how emissions would be computed during malfunctions. Continued compliance with the consent decree, as amended, is not expected to have a material effect on **DP&L's** results of operations, financial condition or cash flows in the future.

Notices of Violation Involving Co-Owned Plants

In November 1999, the USEPA filed civil complaints and NOVs against operators and owners of certain generation facilities for alleged violations of the CAA. Generation units operated by Duke Energy (Beckjord Unit 6) and CSP (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. Although **DP&L** was not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect **DP&L's** co-owned plants.

In June 2000, the USEPA issued an NOV to the **DP&L**-operated J.M. Stuart generating station (co-owned by **DP&L**, Duke Energy, and CSP) for alleged violations of the CAA. The NOV contained allegations that Stuart station engaged in projects between 1978 and 2000 without New Source Review and Prevention of Significant Deterioration permits that resulted in significant increases in particulate matter, SO_2, and NOx. These allegations are consistent with NOVs and complaints that the USEPA had brought against numerous other coal-fired utilities in the Midwest. The NOV indicated the USEPA may: (1) issue an order requiring compliance with the requirements of the Ohio SIP; or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. To date, neither action has been taken. **DP&L** cannot predict the outcome of this matter.

In December 2007, the Ohio EPA issued an NOV to the **DP&L**-operated Killen generating station (co-owned by **DP&L** and Duke Energy) for alleged violations of the CAA. The NOV alleged deficiencies in the continuous monitoring of opacity. We submitted a compliance plan to the Ohio EPA on December 19, 2007. To date, no further actions have been taken by the Ohio EPA.

On March 13, 2008, Duke Energy, the operator of the Zimmer generating station, received an NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio State Implementation Program (SIP) and permits for the station in areas including SO_2, opacity and increased heat input. A second NOV and FOV with similar allegations was issued on November 4, 2010. Also in 2010, USEPA issued an NOV to Zimmer for excess emissions. **DP&L** is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of these matters. Duke Energy is expected to act on behalf of itself and the co-owners with respect to these matters. **DP&L** is unable to predict the outcome of these matters.

Notices of Violation Involving Wholly Owned Plants

In 2007, the Ohio EPA and the USEPA issued NOVs to **DP&L** for alleged violations of the CAA at the Hutchings station. The NOVs' alleged deficiencies related to stack opacity and particulate emissions. Discussions are under way with the USEPA, the U.S. Department of Justice and Ohio EPA. On November 18, 2009, the USEPA issued an NOV to **DP&L** for alleged NSR violations of the CAA at the Hutchings station relating to capital projects performed in 2001 involving Unit 3 and Unit 6. **DP&L** does not believe that the projects described in the NOV were modifications subject to NSR. **DP&L** is engaged in discussions with the USEPA and the U.S. Department of Justice to resolve these matters, but **DP&L** is unable to determine the timing, costs or method by which these issues may be resolved. The Ohio EPA is kept apprised of these discussions.

Environmental Matters Related to Water Quality, Waste Disposal and Ash Ponds

Clean Water Act – Regulation of Water Intake

On July 9, 2004, the USEPA issued final rules pursuant to the Clean Water Act governing existing facilities that have cooling water intake structures. The rules require an assessment of impingement and/or entrainment of organisms as a result of cooling water withdrawal. A number of parties appealed the rules. In April 2009, the U.S. Supreme Court ruled that the USEPA did have the authority to compare costs with benefits in determining

best technology available. The USEPA released new proposed regulations on March 28, 2011, published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. It is anticipated that the final rules will be promulgated in mid-2013. We do not yet know the impact these proposed rules will have on our operations.

Clean Water Act – Regulation of Water Discharge

In December 2006, we submitted an application for the renewal of the Stuart station NPDES Permit that was due to expire on June 30, 2007. In July 2007, we received a draft permit proposing to continue our authority to discharge water from the station into the Ohio River. On February 5, 2008, we received a letter from the Ohio EPA indicating that they intended to impose a compliance schedule as part of the final permit, that requires us to implement one of two diffuser options for the discharge of water from the station into the Ohio River as identified in a thermal discharge study completed during the previous permit term. Subsequently, **DP&L** and the Ohio EPA reached an agreement to allow **DP&L** to restrict public access to the water discharge area as an alternative to installing one of the diffuser options. Ohio EPA issued a revised draft permit that was received on November 12, 2008. In December 2008, the USEPA requested that the Ohio EPA provide additional information regarding the thermal discharge in the draft permit. In June 2009, **DP&L** provided information to the USEPA in response to their request to the Ohio EPA. In September 2010, the USEPA formally objected to a revised permit provided by Ohio EPA due to questions regarding the basis for the alternate thermal limitation. In December 2010, **DP&L** requested a public hearing on the objection, which was held on March 23, 2011. We participated in and presented our position on the issue at the hearing and in written comments submitted on April 28, 2011. In a letter to the Ohio EPA dated September 28, 2011, the USEPA reaffirmed its objection to the revised permit as previously drafted by the Ohio EPA. This reaffirmation stipulated that if the Ohio EPA does not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit will pass to the USEPA. The Ohio EPA issued another draft permit in December 2011 and a public hearing was held on February 2, 2012. The draft permit would require **DP&L**, over the 54 months following issuance of a final permit, to take undefined actions to lower the temperature of its discharged water to a level unachievable by the station under its current design or alternatively make other significant modifications to the cooling water system. **DP&L** submitted comments to the draft permit and is considering legal options. On May 17, 2012, we met with Ohio EPA to discuss this matter. In late August 2012, Ohio EPA provided **DP&L** with a revised draft permit which included some modifications based on our previous comments. We are reviewing this revised draft. Depending on the outcome of the process, the effects could be material on **DP&L's** operations.

In September 2009, the USEPA announced that it will be revising technology-based regulations governing water discharges from steam electric generating facilities. The rulemaking included the collection of information via an industry-wide questionnaire as well as targeted water sampling efforts at selected facilities. It is anticipated that the USEPA will release a proposed rule by late 2012 with a final regulation in place by mid-2014. At present, **DP&L** is unable to predict the impact this rulemaking will have on its operations.

In April 2012, **DP&L** received an NOV related to the construction of the Carter Hollow landfill at the J.M. Stuart station. The NOV indicated that construction activities caused sediment to flow into downstream creeks. In addition, the U.S. Army Corps of Engineers issued a Cease and Desist order followed by a notice suspending the previously issued Corps permit authorizing work associated with the landfill. **DP&L** has installed sedimentation ponds as part of the runoff control measures to address this issue and is working with the various agencies to resolve their concerns including entering into settlement discussions with USEPA, although they have not issued any formal Notice of Violation. This may affect the landfill's construction schedule and delay its operational date. **DP&L** has accrued an immaterial amount for anticipated penalties related to this issue.

Regulation of Waste Disposal

In September 2002, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the South Dayton Dump landfill site. In August 2005, **DP&L** and other parties received a general notice regarding the performance of a Remedial Investigation and Feasibility Study (RI/FS) under a Superfund Alternative Approach. In October 2005, **DP&L** received a special notice letter inviting it to enter into negotiations with the USEPA to conduct the RI/FS. No recent activity has occurred with respect to that notice or PRP status. However, on August 25, 2009, the USEPA issued an Administrative Order requiring that access to **DP&L's** service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. **DP&L** granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against **DP&L** and numerous other defendants alleging

that **DP&L** and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site.

On February 10, 2011, the Court dismissed claims against **DP&L** that related to allegations that chemicals used by **DP&L** at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from **DP&L** that were allegedly directly delivered by truck to the landfill. Discovery, including depositions of past and present **DP&L** employees, is ongoing. In June 2012, **DP&L** filed a motion for summary judgment on grounds that the remaining claims for contribution are barred by a statute of limitations. The plaintiffs oppose that motion and, additionally, have filed a motion seeking Court leave to amend their complaint to add more than 20 new defendants to the case and to recharacterize and re-allege claims against **DP&L** that the Court dismissed in its February 10, 2011 order. On October 26, 2012, **DP&L** received another request to access **DP&L's** service center building site to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. While **DP&L** is unable to predict the outcome of these matters, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

In December 2003, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the Tremont City landfill site. Information available to **DP&L** does not demonstrate that it contributed hazardous substances to the site. While **DP&L** is unable to predict the outcome of this matter, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on us.

On April 7, 2010, the USEPA published an Advance Notice of Proposed Rulemaking announcing that it is reassessing existing regulations governing the use and distribution in commerce of polychlorinated biphenyls (PCBs). While this reassessment is in the early stages and the USEPA is evaluating information from potentially affected parties on how it should proceed, the outcome may have a material adverse effect on **DP&L**. The USEPA has indicated that a proposed rule will be released in late 2012 or early 2013. At present, **DP&L** is unable to predict the impact this initiative will have on its operations.

Regulation of Ash Ponds

In March 2009, the USEPA, through a formal Information Collection Request, collected information on ash pond facilities across the country, including those at Killen and J.M. Stuart stations. Subsequently, the USEPA collected similar information for the Hutchings station.

In August 2010, the USEPA conducted an inspection of the Hutchings station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the Hutchings station ash ponds. **DP&L** is unable to predict whether there will be additional USEPA action relative to **DP&L's** proposed plan or the effect on operations that might arise under a different plan.

In June 2011, the USEPA conducted an inspection of the Killen station ash ponds. In June 2012, the USEPA issued a draft report from the inspection that noted no significant issues with the ash ponds. **DP&L** provided comments on the draft report and **DP&L** is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion byproducts under the Resource Conservation Recovery Act (RCRA). On June 21, 2010, the USEPA published a proposed rule seeking comments on two options under consideration for the regulation of coal combustion byproducts including regulating the material as a hazardous waste under RCRA Subtitle C or as a solid waste under RCRA Subtitle D. The USEPA anticipates issuing a final rule on this topic in late 2012 or early 2013. **DP&L** is unable to predict the financial impact of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse effect on **DP&L's** operations.

Notice of Violation Involving Co-Owned Plants

On September 9, 2011, **DP&L** received a notice of violation from the USEPA with respect to its co-owned J.M. Stuart station based on a compliance evaluation inspection conducted by the USEPA and Ohio EPA in 2009. The notice alleged non-compliance by **DP&L** with certain provisions of the RCRA, the Clean Water Act NPDES permit program and the station's storm water pollution prevention plan. The notice requested that **DP&L** respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on **DP&L's** results of operations, financial condition or cash flow.

Legal and Other Matters

In February 2007, **DP&L** filed a lawsuit against a coal supplier seeking damages incurred due to the supplier's failure to supply approximately 1.5 million tons of coal to two commonly owned plants under a coal supply agreement, of which approximately 570 thousand tons was **DP&L's** share. **DP&L** obtained replacement coal to meet its needs. The supplier has denied liability, and is currently in federal bankruptcy proceedings in which **DP&L** is participating as an unsecured creditor. **DP&L** is unable to determine the ultimate resolution of this matter. **DP&L** has not recorded any assets relating to possible recovery of costs in this lawsuit.

In connection with **DP&L** and other utilities joining PJM, in 2006, the FERC ordered utilities to eliminate certain charges to implement transitional payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, **DP&L** was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments. A hearing was held and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010 that substantially supported **DP&L's** and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. Prior to this final order being issued, **DP&L** entered into a significant number of bilateral settlement agreements with certain parties to resolve the matter, which by design will be unaffected by the final decision. On July 5, 2012, a Stipulation was executed and filed with the FERC that resolved SECA claims against BP Energy Company ("BP") and **DP&L**, AEP (and its subsidiaries) and Exelon Corporation (and its subsidiaries.). On October 1, 2012, **DP&L** received the $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; there is no remaining balance in Other deferred credits relating to SECA.

Lawsuits were filed in connection with the Merger seeking, among other things, one or more of the following: to enjoin consummation of the Merger until certain conditions were met, to rescind the Merger or for rescissory damages, or to commence a sale process and/or obtain an alternative transaction or to recover an unspecified amount of other damages and costs, including attorneys' fees and expenses, a constructive trust or an accounting from the individual defendants for benefits they allegedly obtained as a result of their alleged breach of duty. All of these lawsuits, except one, were resolved and/or dismissed prior to the March 28, 2012 filing of our Form 10-K for the fiscal year ending December 31, 2011, and were discussed in that and previous reports we filed. The last of these lawsuits was dismissed on March 29, 2012.

13. Fixed-asset Impairment
On October 5, 2012, **DP&L** filed for approval an ESP with the PUCO which reflects a shift in our outlook for the regulatory environment. Within the ESP filing, **DP&L** agreed to request a separation of its generation assets from its transmission and distribution assets in recognition that a restructuring of **DP&L** operations will be necessary, in compliance with Ohio law. Also, during 2012, North American natural gas prices fell significantly from the previous year, exerting downward pressure on wholesale electricity prices in the Ohio power market. Falling power prices have compressed wholesale margins at **DP&L's** generating plants. Furthermore, these lower power prices have led to increased customer switching from **DP&L** to CRES providers, who are offering retail prices lower than **DP&L's** standard service offer. Also, several municipalities in **DP&L's** service territory have passed ordinances allowing them to become government aggregators with some having already contracted with CRES providers, further contributing to the switching trend. In September 2012, management revised its cash flow forecasts based on these developments as part of its annual budgeting process and forecasted lower operating cash flows than in prior reporting periods. Collectively, in the third quarter of 2012, these events were considered to be an impairment indicator for the long-lived asset group as management believes that these developments represent a significant adverse change in the business climate that could affect the value of the long-lived asset group.
The long-lived asset group subject to the impairment evaluation was determined to be each individual plant of **DP&L**. This determination was based on the assessment of the plants' ability to generate independent cash flows. When the recoverability test of the long-lived asset group was performed, management concluded that, on an undiscounted cash flow basis, the carrying amount of two plants, Conesville and Hutchings, were not recoverable. To measure the amount of impairment loss, management was required to determine the fair value of the two plants. Cash flow forecasts and the underlying assumptions for the valuation were developed by

management. While there were numerous assumptions that impact the fair value, forward power prices, dark spreads and the transition to a merchant model were the most significant.
In determining the fair value of the Conesville plant, the three valuation approaches prescribed by the fair value measurement accounting guidance were considered. The fair value under the income approach was considered the most appropriate and resulted in a $25.0 million fair value. The carrying value of the Conesville plant prior to the impairment was $97.5 million. Accordingly, the Conesville plant was considered impaired and $72.5 million of impairment expense was recognized in the third quarter of 2012.
In determining the fair value of the Hutchings plant, the three valuation approaches prescribed by the fair value measurement accounting guidance were considered. The fair value under the income approach was considered the most appropriate and resulted in a zero fair value. The carrying value of the Hutchings plant prior to the impairment was $8.3 million. Accordingly, the Hutchings plant was considered impaired and $8.3 million of impairment expense was recognized in the third quarter of 2012.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
This report includes the combined filing of **DPL** and **DP&L**. On November 28, 2011, **DPL** became a wholly owned subsidiary of AES, a global power company. Throughout this report, the terms "we," "us," "our" and "ours" are used to refer to both **DPL** and **DP&L**, respectively and altogether, unless the context indicates otherwise. Discussions or areas of this report that apply only to **DPL** or **DP&L** will clearly be noted in the section.
The following discussion contains forward-looking statements and should be read in conjunction with the accompanying Condensed Consolidated Financial Statements and related footnotes of **DPL** and the Condensed Financial Statements and related footnotes of **DP&L** included in **Part I – Financial Information**, the risk factors in Item 1A to Part I of our Form 10-K for the fiscal year ending December 31, 2011 and in Item 1A to Part II of this Quarterly Report on Form 10-Q, and our "Forward-Looking Statements" section on page 8 of this Form 10-Q. For a list of certain abbreviations or acronyms in this discussion, see Glossary at the beginning of this Form 10-Q.

DESCRIPTION OF BUSINESS

DPL is a diversified regional energy company organized in 1985 under the laws of Ohio. **DPL's** two reportable segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary. Refer to Note 14 of Notes to **DPL's** Condensed Consolidated Financial Statements for more information relating to these reportable segments.
On November 28, 2011, **DPL** was acquired by AES in the Merger and **DPL** became a wholly owned subsidiary of AES. See Note 2 of Notes to **DPL's** Condensed Consolidated Financial Statements.

DP&L is a public utility incorporated in 1911 under the laws of Ohio. **DP&L** is engaged in the generation, transmission, distribution and sale of electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. Electricity for **DP&L's** 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense.

DP&L's sales reflect the general economic conditions and seasonal weather patterns of the area. **DP&L** sells any excess energy and capacity into the wholesale market.

DPLER sells competitive retail electric service, under contract, to residential, commercial and industrial customers. DPLER's operations include those of its wholly owned subsidiary, MC Squared, which was acquired on February 28, 2011. DPLER has approximately 175,000 customers currently located throughout Ohio and Illinois. DPLER does not own any transmission or generation assets, and all of DPLER's electric energy was purchased from **DP&L** or PJM to meet its sales obligations. DPLER's sales reflect the general economic conditions and seasonal weather patterns of the areas it serves.

DPL's other significant subsidiaries include DPLE, which owns and operates peaking generating facilities from which it makes wholesale sales of electricity and MVIC, our captive insurance company that provides insurance services to us and our subsidiaries. All of **DPL's** subsidiaries are wholly owned.

DPL also has a wholly owned business trust, DPL Capital Trust II, formed for the purpose of issuing trust capital securities to investors.

DP&L's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law. Accordingly, **DP&L** applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates, and regulatory liabilities when current cost recoveries in customer rates relate to expected future costs.

DPL and its subsidiaries employed 1,501 people as of September 30, 2012, of which 1,443 employees were employed by **DP&L**. Approximately 52% of all employees are under a collective bargaining agreement which expires on October 31, 2014.

BUSINESS COMBINATION

Acquisition by The AES Corporation

On November 28, 2011, **DPL** merged with Dolphin Sub, Inc., a wholly owned subsidiary of The AES Corporation, a Delaware corporation ("AES") pursuant to the Agreement and Plan of Merger (the "Merger Agreement") whereby AES acquired **DPL** for $30.00 per share in a cash transaction valued at approximately $3.5 billion. At closing, **DPL** became a wholly owned subsidiary of AES.

Dolphin Subsidiary II, Inc., a subsidiary of AES, issued $1,250.0 million in long-term Senior Notes on October 3, 2011, to partially finance the Merger (see Note 2 of Notes to **DPL's** Condensed Consolidated Financial Statements). Upon the consummation of the Merger, Dolphin Subsidiary II, Inc. was merged into **DPL** and these notes became long-term debt obligations of **DPL**. This debt has and will have a material effect on **DPL's** cash requirements.

As a result of the Merger, including the assumption of merger-related debt, **DPL** and **DP&L** were downgraded by all three major credit rating agencies. We do not anticipate that these reduced ratings will have a significant effect on our liquidity; however, we expect that our cost of capital will increase. See Note 6 of Notes to **DPL's** Condensed Consolidated Financial Statements for more information.

DPL incurred merger transaction costs consisting primarily of banker's fees, legal fees and change of control costs of approximately $53.6 million pre-tax during 2011 and an additional $1.0 million pre-tax during 2012. Other than these costs, interest on the additional debt and other items noted above, **DPL** and **DP&L** do not expect the Merger to have a significant effect on their financial position, results of operations or sources of liquidity during 2012.

The Merger also resulted in **DPL** recording $2,576.3 million in goodwill due to the push down of purchase accounting in accordance with FASC 805. Utilities in Ohio continue to face downward pressure on operating margins due to the evolving regulatory environment, which is moving towards a market-based competitive pricing mechanism. At the same time, declining energy prices are also reducing operating margins across the utility industry. These competitive forces could adversely impact the future operating performance of **DPL** and may result in impairment of its goodwill.

Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if impairment indicators are present. In evaluating the potential impairment of goodwill, we make estimates and assumptions about revenue, operating cash flows, capital expenditures, growth rates and discount rates based on our budgets and long term forecasts, macroeconomic projections, and current market expectations of returns on similar assets. There are inherent uncertainties related to these factors and management's judgment in applying these factors. Generally, the fair value of a reporting unit is determined using a discounted cash flow valuation model. We could be required to evaluate the potential impairment of goodwill outside of the required annual assessment process if we experience situations, including but not limited to: deterioration in general economic conditions, operating or regulatory environment; increased competitive environment; increase in fuel costs particularly when we are unable to pass along such costs to customers; negative or declining cash flows; loss of a key contract or customer particularly when we are unable to replace it on equally favorable terms; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. A goodwill impairment could lead to a rating downgrade and adversely impact the trading price of **DPL's** bonds.

See Note 15 in **DPL's** Condensed Consolidated Financial Statements for more information regarding the write-off of a portion of **DPL's** goodwill during the three months ended September 30, 2012.

DPL will perform its next annual goodwill impairment evaluation in the fourth quarter of 2013.

Predecessor and Successor Financial Presentation

DPL's financial statements and related financial and operating data include the periods before and after the Merger with AES on November 28, 2011, and are labeled as Predecessor and Successor, respectively. In accordance with GAAP, **DPL** applied push-down accounting to account for the merger. For accounting purposes only, push-down accounting created a new cost basis assigned to assets, liabilities and equity as of the Merger date. Such adjustments were subject to change as AES finalized its purchase price allocation during the applicable measurement period.

REGULATORY ENVIRONMENT

DPL, **DP&L** and our subsidiaries' facilities and operations are subject to a wide range of environmental regulations and laws by federal, state and local authorities. As well as imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at these facilities to comply, or to determine compliance, with such regulations. We record liabilities for losses that are probable of occurring and can be reasonably estimated.

- **Carbon and Other Greenhouse Gas Emissions**

  There is an on-going concern nationally and internationally about global climate change and the contribution of emissions of GHGs, including most significantly CO_2. This concern has led to regulation and interest in legislation at the federal level, actions at the state level as well as litigation relating to GHG emissions. In 2007, a U.S. Supreme Court decision upheld that the USEPA has the authority to regulate GHG emissions under the CAA. In April 2009, the USEPA issued a proposed endangerment finding under the CAA. The proposed finding determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This endangerment finding became effective in January 2010. Numerous affected parties have asked the USEPA Administrator to reconsider this decision.

  As a result of this endangerment finding and other USEPA regulations, emissions of CO_2 and other GHGs from certain electric generating units and other stationary sources are subject to regulation. Increased pressure for GHG emissions reduction is also coming from investor organizations and the international community. Environmental advocacy groups are also focusing considerable attention on GHG emissions from power generation facilities and their potential role in climate change. Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of GHG emissions at generating stations we own and co-own is approximately 16 million tons annually. If we are required to implement control of CO_2 and other GHGs at generation facilities, the cost to **DPL** and **DP&L** of such reductions could be material.

- **Clean Water Act**

  In April 2012, **DP&L** received an NOV related to the construction of the Carter Hollow landfill at the J.M. Stuart station. The NOV indicated that construction activities caused sediment to flow into downstream creeks. In addition, the U.S. Army Corps of Engineers issued a Cease and Desist order followed by a notice suspending the previously issued Corps permit authorizing work associated with the landfill. USEPA has indicated that they may take additional enforcement action. **DP&L** has installed sedimentation ponds as part of the runoff control measures to address this issue and is working with the various agencies to resolve their concerns including entering into settlement discussions with USEPA, although they have not issued any formal Notice of Violation. This may affect the landfill's construction schedule and delay its operational date. **DP&L** has accrued an immaterial amount for anticipated penalties related to this issue.

- **Electric Security Plan**

SB 221 requires that all Ohio distribution utilities file either an ESP or MRO to establish rates for their SSO. Under the MRO, a periodic competitive bid process will set the retail generation price after the utility demonstrates that it can meet certain market criteria and bid requirements. Also, under this option, utilities that still own generation in the state are required to phase-in the MRO over a period of not less than five years. An ESP may allow for adjustments to the SSO for costs associated with environmental compliance; fuel and purchased power; construction of new or investment in specified generating facilities; and the provision of standby and default service, operating, maintenance, or other costs including taxes. As part of its ESP, a utility is permitted to file an infrastructure improvement plan that will specify the initiatives the utility will take to rebuild, upgrade, or replace its electric distribution system, including cost recovery mechanisms. Both MRO and ESP options involve a "significantly excessive earnings test" (SEET) based on the earnings of comparable companies with similar business and financial risks. According to DP&L's current ESP, **DP&L** becomes subject to the SEET in 2013 based on 2012 earnings results and the SEET review could result in no adjustment to our SSO rates or a refund to customers. The effect may or may not be significant.

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On March 30, 2012, DP&L filed with the PUCO for approval of its next rate plan to replace the existing rate plan that expires on December 31, 2012. The filing requested approval of the five year and five month MRO, which would have been effective January 1, 2013, and would have phased in market rates over this period. The initial filing indicated that the proposed MRO rates, if approved by the PUCO, would reduce DP&L's revenues by approximately $30 million in the first year after they are applied, based on the level of SSO sales contained in the filing. After several months of negotiation with over 26 diverse intervening parties, on September 7, 2012, DP&L withdrew the March 2012 filing and filed an ESP on October 5, 2012.

On October 5, 2012 DP&L filed an ESP with the PUCO. The plan requests approval of a non-bypassable Service Stability Rider (SSR) that is designed to recover $120 million per year for five years. This is a net rate increase of approximately $47 million per year over DP&L's prior non-bypassable charge. DP&L also requests approval of a switching tracker that would measure the incremental amount of switching over a base case and defer the lost value into a regulatory asset which would be recovered from all customers beginning January 2014. The ESP states that DP&L intends to file on or before December 31, 2013 its plan for legal separation of its generation assets. The ESP proposes a three year, five month transition to market, whereby a wholesale competitive bidding structure will be phased in to supply generation service to customers located in DP&L's service territory that have not chosen an alternative generation supplier. DP&L's standard offer generation revenues are projected to decrease overall as a result of this filing by approximately $52 million for the first year, due to a portion of DP&L's SSO load being sourced through a competitive bid and other adjustments that were made to the SSO generation rates. As more SSO supply is sourced through a competitive bid, DP&L will continue to experience a decrease in SSO generation revenues each year throughout the blending period. DP&L's retail transmission rates will increase as a retail, non-bypassable transmission charge will be implemented; however, this revenue is offset slightly by a decrease in wholesale transmission revenues from CRES Providers operating in DP&L's service territory.

- **SB 221 Renewable and Energy Efficiency Requirements**

SB 221 and the implementation rules contain targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards. The standards require that, by the year 2025, 25% of the total number of kWh of electricity sold by the utility to retail electric consumers must come from alternative energy resources, which include "advanced energy resources" such as distributed generation, clean coal, advanced nuclear, energy efficiency and fuel cell technology; and "renewable energy resources" such as solar, hydro, wind, geothermal and biomass. At least half of the 25% must be generated from renewable energy resources, including 0.5% from solar energy. The renewable energy portfolio, energy efficiency and demand reduction standards began in 2009 with increased percentage requirements each year thereafter. The annual targets for energy efficiency and peak demand reductions began in 2009 with annual increases. Energy efficiency programs are expected to save 22.3% by 2025 and peak demand reductions are expected to reach 7.75% by 2018 compared to a baseline energy usage. If any targets are not met, compliance penalties will apply, unless the PUCO makes certain findings that would excuse performance.

- **NOx and SO_2 Emissions – CSAPR**

  The USEPA promulgated the "Clean Air Interstate Rule" (CAIR) on March 10, 2005, which required allowance surrender for SO_2 and NOx emissions from existing power plants located in 28 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase was to begin in 2009 and 2010 for NOx and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions was to begin in 2015. To implement the required emission reductions for this rule, the states were to establish emission allowance based "cap-and-trade" programs. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the USEPA.

In response to the D.C. Circuit's opinion, on July 7, 2011, the USEPA issued a final rule titled "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States," which is now referred to as the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, CSAPR would have required significant reductions in SO_2 and NOx emissions from covered sources, such as power plants. Once fully implemented in 2014, the rule would require additional SO_2 emission reductions of 73% and additional NOx reductions of 54% from 2005 levels. Many states, utilities and other affected parties filed petitions for review, challenging the CSAPR before the U.S. Court of Appeals for the District of Columbia. A large subset of the Petitioners also sought a stay of the CSAPR. On December 30, 2011, the D.C. Circuit granted a stay of the CSAPR and directed the USEPA to continue administering CAIR. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that USEPA overstepped its regulatory authority by requiring

states to make reductions beyond the levels required in the CAA and failed to provide states an initial opportunity to adopt their own measures for achieving federal compliance. As a result of this ruling, the surviving provisions of CAIR will continue to serve as the governing program until USEPA takes further action or the U.S. Congress intervenes. Assuming that USEPA constructs a replacement interstate transport rule addressing the D.C. Circuit Court's ruling, it will likely take three years or more before companies would be required to comply with a replacement rule. At this time, it is not possible to predict the details of such a replacement transport rule or what impacts it may have on our consolidated financial condition, results of operations or cash flows. On October 5, 2012, USEPA, several states and cities, as well as environmental and health organizations, filed petitions with the D.C. Circuit Court requesting a rehearing by all of the judges of the D.C. Circuit Court of the case pursuant to which the three-judge panel ruled that CSAPR be vacated. As of November 6, 2012, the D.C. Circuit Court had not ruled on USEPA's petition for rehearing. We cannot predict whether the D.C. Circuit Court will grant a rehearing or, if a rehearing is granted, whether CSAPR will be ultimately reinstated and implemented in its current form or a modified form. If CSAPR were to be reinstated in its current form, we do not expect any material capital costs for **DP&L's** plants, assuming Beckjord 6 and Hutchings generating stations will not operate on coal in 2015 due to implementation of the Mercury and Air Toxics Standards. Because we cannot predict the final outcome of the CSAPR rulemaking, we cannot predict its financial impact on **DP&L's** operations.

COMPETITION AND PJM PRICING

- **RPM Capacity Auction Price**

  The PJM RPM capacity base residual auction for the 2015/2016 period cleared at a per megawatt price of $136/day for our RTO area. The per megawatt prices for the periods 2014/2015, 2013/2014, 2012/2013, and 2011/2012 were $126/day, $28/day, $16/day, and $110/day, respectively, based on previous auctions. Future RPM auction results will be dependent not only on the overall supply and demand of generation and load, but may also be impacted by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions. The SSO retail costs and revenues are included in the RPM rider. Therefore, increases in customer switching causes more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. We cannot predict the outcome of future auctions or customer switching but based on actual results attained in 2011, we estimate that a hypothetical increase or decrease of $10 in the capacity auction price would result in an annual impact to net income of approximately $5.1 million and $3.8 million for **DPL** and **DP&L**, respectively. These estimates do not, however, take into consideration the other factors that may affect the impact of capacity revenues and costs on net income such as the levels of customer switching, our generation capacity, the levels of wholesale revenues and our retail customer load. These estimates are discussed further within Commodity Pricing Risk under the Market Risk section of this Management Discussion & Analysis.

- **Ohio Competitive Considerations and Proceedings**

Since January 2001, **DP&L's** electric customers have been permitted to choose their retail electric generation supplier. **DP&L** continues to have the exclusive right to provide delivery service in its state certified territory and the obligation to supply retail generation service to customers that do not choose an alternative supplier. The PUCO maintains jurisdiction over **DP&L's** delivery of electricity, SSO and other retail electric services.

Lower market prices for power have resulted in increased levels of competition to provide transmission and generation services. This in turn has led approximately 57% of **DP&L's** retail volume to be switched to CRES providers. DPLER, an affiliated company and one of the registered CRES providers, has been marketing transmission and generation services to **DP&L** customers. The following table provides a summary of the number of electric customers and volumes provided by all CRES providers in our service territory during the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30, 2012		Three Months Ended September 30, 2011	
	Electric Customers	**Sales (in Millions of kWh)**	Electric Customers	Sales (in Millions of kWh)
	Successor		Predecessor	
Supplied by DPLER	**59,241**	**1,671**	21,990	1,567
Supplied by non-affiliated CRES providers	**69,127**	**562**	19,285	283
Total supplied in our service territory by DPLER and other CRES providers	**128,368**	**2,233**	41,275	1,850
Distribution sales by **DP&L** in our service territory [(a)]	**512,191**	**3,795**	512,424	3,874

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
	Electric Customers	**Sales (in Millions of kWh)**	Electric Customers	Sales (in Millions of kWh)
	Successor		Predecessor	
Supplied by DPLER	**59,241**	**4,668**	21,990	4,330
Supplied by non-affiliated CRES providers	**69,127**	**1,428**	19,285	566
Total supplied in our service territory by DPLER and other CRES providers	**128,368**	**6,096**	41,275	4,896
Distribution sales by **DP&L** in our service territory [(a)]	**512,191**	**10,694**	512,424	10,772

[(a)] The volumes supplied by DPLER represent approximately 44% and 40% of **DP&L's** total distribution volumes during the three months ended September 30, 2012 and 2011, respectively, and 44% and 40% during the nine months ended September 30, 2012 and 2011, respectively. We cannot determine the extent to which customer switching to CRES providers will occur in the future and the effect this will have on our operations, but any additional switching could have a significant adverse effect on our future results of operations, financial condition and cash flows.

As of September 30, 2012, approximately 57% of **DP&L's** load has switched to CRES providers with DPLER acquiring 77% of the switched load. For the nine months ended September 30, 2012, customer switching negatively affected **DPL's** gross margin by approximately $37.0 million compared to the 2011 effect of approximately $39.4 million. For the nine months ended September 30, 2012, customer switching negatively affected **DP&L's** gross margin by approximately $66.0 million compared to the 2011 effect of $65.7 million.

Several communities in **DP&L's** service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering alternative electric generation supplies to their citizens. To date, a number of organizations have filed with the PUCO to initiate aggregation programs. If a number of the larger organizations move forward with aggregation, it could have a material effect on our earnings.

FUEL AND RELATED COSTS

- **Fuel and Commodity Prices**

The coal market is a global market in which domestic prices are affected by international supply disruptions and demand balance. In addition, domestic issues like government-imposed direct costs and permitting issues are affecting mining costs and supply availability. Our approach is to hedge the fuel costs for our anticipated electric sales. For the year ending December 31, 2012, we have hedged substantially all our coal requirements to meet our committed sales. We may not be able to hedge the entire exposure of our operations from commodity price volatility. If our suppliers do not meet their contractual commitments or we are not hedged against price volatility and we are unable to recover costs through the fuel and purchased power recovery rider, our results of operations, financial condition or cash flows could be materially affected.

RESULTS OF OPERATIONS – DPL

DPL's results of operations include the results of its subsidiaries, including the consolidated results of its principal subsidiary **DP&L**. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for **DP&L** is presented elsewhere in this report.

Income Statement Highlights – DPL

$ in millions	Three Months Ended September 30, 2012 Successor	Three Months Ended September 30, 2011 Predecessor	Nine Months Ended September 30, 2012 Successor	Nine Months Ended September 30, 2011 Predecessor
Revenues:				
Retail	$ **387.2**	$ 396.1	$ **1,060.7**	$ 1,102.0
Wholesale	**43.5**	40.7	**78.2**	101.8
RTO revenues	**34.7**	22.3	**72.6**	63.2
RTO capacity revenues	**5.5**	37.3	**69.0**	142.3
Other revenues	**2.8**	2.8	**8.5**	8.5
Other mark-to-market (losses)	**(2.0)**	(1.6)	**(1.3)**	(6.3)
Total revenues	**471.7**	497.6	**1,287.7**	1,411.5
Cost of revenues:				
Fuel costs	**119.2**	121.8	**278.8**	312.7
Losses / (gains) from sale of coal	**3.1**	(3.9)	**8.4**	(6.8)
Mark-to-market losses / (gains)	**(9.6)**	11.1	**(8.2)**	15.0
Net fuel	**112.7**	129.0	**279.0**	320.9
Purchased power	**53.5**	39.7	**127.4**	120.3
RTO charges	**30.9**	34.5	**77.0**	90.9
RTO capacity charges	**5.9**	35.5	**62.3**	138.0
Mark-to-market losses / (gains)	**0.4**	(1.4)	**(0.9)**	(6.5)
Net purchased power	**90.7**	108.3	**265.8**	342.7
Amortization of intangibles	**24.2**	-	**71.2**	-
Total cost of revenues	**227.6**	237.3	**616.0**	663.6
Gross margins *(a)*	$ **244.1**	$ 260.3	$ **671.7**	$ 747.9
Gross margin as a percentage of revenues	**52%**	52%	**52%**	53%

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Operating income	$ (1,761.3)	$ 112.9	$ (1,644.7)	$ 279.5

(a) *For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.*

(b)

DPL – Revenues

Retail customers, especially residential and commercial customers, consume more electricity on warmer and colder days. Therefore, our retail sales volume is impacted by the number of heating and cooling degree days occurring during a year. Cooling degree days typically have a more significant impact than heating degree days since some residential customers do not use electricity to heat their homes.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	**2012**	2011
	Successor	Predecessor	**Successor**	Predecessor
Heating degree days *(a)*	**110**	124	**2,828**	3,604
Cooling degree days *(a)*	**825**	839	**1,255**	1,158

(a) Heating and cooling degree days are a measure of the relative heating or cooling required for a home or business. The heating degrees in a day are calculated as the difference of the average actual daily temperature below 65 degrees Fahrenheit. If the average temperature on March 20th was 40 degrees Fahrenheit, the heating degrees for that day would be the 25 degree difference between 65 degrees and 40 degrees. In a similar manner, cooling degrees in a day are the difference of the average actual daily temperature in excess of 65 degrees Fahrenheit.

Since we plan to utilize our internal generating capacity to supply our retail customers' needs first, increases in retail demand may decrease the volume of internal generation available to be sold in the wholesale market and vice versa. The wholesale market covers a multi-state area and settles on an hourly basis throughout the year. Factors impacting our wholesale sales volume each hour of the year include: wholesale market prices; our retail demand; retail demand elsewhere throughout the entire wholesale market area; our plants' and other utility plants' availability to sell into the wholesale market and weather conditions across the multi-state region. Our plan is to make wholesale sales when market prices allow for the economic operation of our generation facilities not being utilized to meet our retail demand or when margin opportunities exist between the wholesale sales and power purchase prices.

The following table provides a summary of changes in revenues from the prior period:

$ in millions	Three Months Ended September 30, 2012 vs. 2011	Nine Months Ended September 30, 2012 vs. 2011
Retail		
Rate	$ (22.0)	$ (20.4)
Volume	14.9	(19.0)
Other miscellaneous	(1.8)	(1.9)
Total retail change	(8.9)	(41.3)
Wholesale		
Rate	(16.0)	(12.5)
Volume	18.8	(11.1)
Total wholesale change	2.8	(23.6)
RTO capacity & other		
RTO capacity and other revenues	(19.4)	(63.9)
Other		
Unrealized MTM	(0.4)	5.0
Other	-	-
Total other revenue	(0.4)	5.0
Total revenues change	$ (25.9)	$ (123.8)

For the three months ended September 30, 2012, Revenues decreased $25.9 million to $471.7 million from $497.6 million in the same period of the prior year. This decrease was primarily the result of lower retail and wholesale sales volume, a decrease in average retail rates and a decrease in RTO capacity and other RTO revenues, offset slightly by higher retail and wholesale sales volume.

- Retail revenues decreased $8.9 million primarily due to customer switching as a result of increased levels of competition to provide transmission and generation services in our service territory. Also contributing to the decrease was unfavorable weather; during the three months there was a 2% decrease in the number of cooling degree days to 825 days from 839 days in 2011, as well as a 12% decrease in the number of heating degree days to 110 days from 124 days in 2011. The effect of sales procured by DPLER and MC Squared outside our service territory, or off-system sales, caused sales volume to increase 4%, however, the rates offered to the off-system customers are lower than the rates in our service territory causing an overall 5% decrease in average rates. The above resulted in an unfavorable $22.0 million retail price variance offset by a favorable $14.9 million retail sales volume variance.
- Wholesale revenues increased $2.8 million primarily as a result of a 46% increase in wholesale sales volume which was largely a result of higher generation by our power plants, offset slightly by a 27% decrease in average wholesale prices. This resulted in a favorable $18.8 million wholesale sales volume variance offset by an unfavorable wholesale price variance of $16.0 million.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $19.4 million compared to the same period in 2011. This decrease in RTO capacity and other revenues was the result of a $31.8 million decrease in revenues realized from the PJM capacity auction offset by a $12.4 million increase in transmission and congestion revenues from the receipt of the SECA settlement.

For the nine months ended September 30, 2012, Revenues decreased $123.8 million to $1,287.7 million from $1,411.5 million in the same period of the prior year. This decrease was primarily the result of lower retail and wholesale sales volume, lower retail and wholesale average rates and a decrease in RTO capacity and other RTO revenues.

- Retail revenues decreased $41.3 million resulting primarily from a 2% decrease in retail sales volume compared to the prior year. The unfavorable weather conditions resulted in a 22% decrease in the number of heating degree days to 2,828 days from 3,604 days in 2011 offset slightly by a 9% increase in the number of cooling degree days to 1,255 days from 1,158 days in 2011. The decrease in sales volume is affected by the lower revenues due to customer switching which has resulted from increased levels of competition to provide transmission and generation services in our service territory. However, the decrease was slightly offset by the procurement of sales by DPLER and MC Squared outside our service territory as discussed in the previous section. The decrease in sales volume was partially offset by improved economic conditions as well. The above resulted in an unfavorable $20.4 million retail price variance and an unfavorable $19.0 million retail sales volume variance.
- Wholesale revenues decreased $23.6 million primarily as a result of an 11% decrease in wholesale sales volume which was largely a result of lower generation by our power plants, including a 14% decrease in average wholesale prices. This resulted in an unfavorable $12.5 million wholesale price variance and an unfavorable wholesale sales volume variance of $11.1 million.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $63.9 million compared to the same period in 2011. This decrease in RTO capacity and other revenues was primarily the result of a $73.3 million decrease in revenues realized from the PJM capacity auction partially offset by an increase in transmission and congestion revenues.

DPL – Cost of Revenues

For the three months ended September 30, 2012:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $16.3 million, or 13%, during the quarter ended September 30, 2012 compared to the same period in 2011. This decrease was largely due to unrealized MTM gains of $9.6 million for the three months ended September 30, 2012 versus $11.1 million of MTM losses during the same period in 2011. Also contributing to this decrease was a $2.6 million decrease in fuel costs driven by a 1% decrease in the volume of generation at our plants. Partially offsetting the decreases were $3.1 million in realized losses from **DP&L's** sale of coal, compared to $3.9

million of realized gains during the same period in 2011.

- Net purchased power decreased $17.6 million, or 16%, compared to the same period in 2011 due largely to a $33.2 million decrease in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This decrease included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Partially offsetting this decrease was an increase in purchased power costs of $13.8 million, or 35%, compared to the same period in 2011, as well as a decrease in unrealized MTM gains of $1.8 million. The increase in purchased power costs was driven by an increase in purchased power volumes of 58%, partially offset by a decrease in purchased power prices of approximately 15%. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.
- Amortization of intangibles increased $24.2 million compared to the same period in 2011 due to the intangibles recorded at the Merger date.

For the nine months ended September 30, 2012:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $41.9 million, or 13%, during the nine months ended September 30, 2012 compared to the same period in 2011. This decrease was largely due to a $33.9 million decrease in fuel costs driven by an 11% decrease in the volume of generation at our plants. Also contributing to this decrease were realized losses from **DP&L's** sale of coal of $8.4 million for the nine months ended September 30, 2012 versus $6.8 million in realized gains during the same period in 2011. Partially offsetting the decreases were $8.2 million in unrealized MTM gains compared to $15.0 million of unrealized MTM losses during the same period in 2011.
- Net purchased power decreased $76.9 million, or 22%, compared to the same period in 2011 due largely to an $89.6 million decrease in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This decrease included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Partially offsetting this decrease was an increase in purchased power costs of $7.1 million, or 6%, compared to the same period in 2011, as well as a decrease in unrealized MTM gains of $5.6 million. The increase in purchased power costs was driven by an increase in purchased power volumes of 33%, partially offset by a decrease in purchased power prices of approximately 21%. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.
- Amortization of intangibles increased $71.2 million compared to the same period in 2011 due to the intangibles recorded at the Merger date.

DPL – Operation and Maintenance

The following table provides a summary of changes in operation and maintenance expense from the prior period.

$ in millions	Three Months Ended September 30, 2012 vs. 2011	Nine Months Ended September 30, 2012 vs. 2011
Low-income payment program [(1)]	$ 5.7	$ 16.1
Energy efficiency program [(1)]	4.0	8.8
Competitive retail operations	0.9	5.8
Maintenance of overhead transmission and distribution lines	2.5	(3.9)
Generating facilities operating and maintenance expense	2.0	3.2
Pension related expense	1.1	(0.3)
Deferred compensation	(0.5)	(2.6)
Merger related costs	(3.7)	(8.2)
Other, net	2.6	(5.0)
Total change in operation and maintenance expense	$ 14.6	$ 13.9

(1) There is a corresponding increase in Revenues associated with this program resulting in no impact to Net Income.

During the three months ended September 30, 2012, Operation and maintenance expense increased $14.6 million, or 16%, compared to the same period in 2011. This variance was primarily the result of:

- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased expenses relating to energy efficiency programs that were put in place for our customers,
- increased marketing, customer maintenance and labor costs associated with the competitive retail business as a result of increased sales volume and number of customers,
- increase in expenses related to the maintenance of overhead transmission and distribution lines due to the derecho storm in late June, partially offset by decreased non-storm related expenses,
- increased expenses for generating facilities largely due to the length and timing of planned outages at jointly owned production units relative to the same period in 2011, and
- higher pension expenses primarily related to a one-time SERP settlement charge of $0.6M which was recorded as a July 2012 lump-sum payment to a SERP participant triggered by settlement accounting for the SERP as well as changes in plan assumptions, specifically a lower discount rate and lower expected rate of return on plan assets.

These increases were partially offset by:

- higher costs in the prior year related to the Merger, and
- decreased expenses related to deferred compensation arrangements primarily due to fewer equity awards in the current period.

During the nine months ended September 30, 2012, Operation and maintenance expense increased $13.9 million, or 5%, compared to the same period in 2011. This variance was primarily the result of:

- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increase expenses relating to energy efficiency programs that were put in place for our customers,
- increased marketing, customer maintenance and labor costs associated with the competitive retail business as a result of increased sales volume and number of customer, and
- increased expenses for generating facilities largely due to the length and timing of planned outages at jointly owned production units relative to the same period in 2011.

These increases were partially offset by:

- decreased expenses related to the maintenance of overhead transmission and distribution lines primarily as a result of storms, including a significant ice storm in February 2011,
- higher costs in the prior year related to the Merger,
- decreased expenses related to deferred compensation arrangements primarily related to fewer equity awards in the current periods, and
- lower pension expenses primarily related to the elimination of certain unrecognized actuarial losses and prior service costs as a result of purchase accounting due to the Merger. These amounts were previously recorded in Accumulated Other Comprehensive Income and recognized in pension expense over the remaining service life of plan participants.

On August 10, 2012, **DP&L** filed with the PUCO for an accounting order for permission to defer operation and maintenance costs as a result of damage caused by storms occurring during the final weekend of June 2012. The deferral request is for distribution expense incurred for these storms. The deferral would earn a return equal to the carrying cost of debt (5.86%) until these costs are recovered from customers. On October 19, 2012, **DP&L** amended its filing to change the method of calculating the deferral. If PUCO approval is received, **DP&L** will defer approximately $5.8 million of costs associated with these storms.

DPL – Depreciation and Amortization

For the three and nine months ended September 30, 2012, Depreciation and amortization expense decreased $2.7 million, or 8%, and $10.4 million, or 10%, respectively, as compared to 2011. The decreases primarily reflect the effect of the purchase accounting which resulted in estimated fair values of our plants below the carrying values at the Merger date. This was partially offset by increased amortization expense due to amortization resulting from the increase in the estimated value of certain intangibles acquired in the Merger.

DPL – General Taxes

For the three and nine months ended September 30, 2012, General taxes decreased $3.9 million, or 20%, and $5.5 million, or 9%, respectively, as compared to 2011. This decrease was primarily the result of an unfavorable 2011 determination from the Ohio gross receipts tax audit as well as the release of a property tax reserve related to the purchase accounting property revaluations partially offset by higher property tax accruals in 2012 compared to 2011.

Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, these taxes are accounted for on a net basis and are recorded as a reduction in revenues for presentation in accordance with AES policy. The 2011 amount was reclassified to conform to this presentation.

DPL – Interest Expense

For the three months ended September 30, 2012, Interest expense increased $14.3 million, or 85%, as compared to 2011 due primarily to higher interest cost subsequent to the Merger as a result of the $1,250.0 million of debt that was assumed by **DPL** in connection with the AES Merger.

For the nine months ended September 30, 2012, Interest expense increased $41.8 million, or 81%, as compared to 2011 due primarily to higher interest cost subsequent to the Merger as a result of the $1,250.0 million of debt that was assumed by **DPL** in connection with the AES Merger.

DPL – Charge for Early Redemption of Debt

The Charge for early redemption of debt reflects the purchase in February 2011 of $122.0 million principal of the DPL Capital Trust II 8.125% capital securities in a privately negotiated transaction. As part of this transaction, **DPL** paid a $12.2 million, or 10%, premium and wrote off $3.1 million of unamortized discount and issuance costs.

DPL – Income Tax Expense

For the three and nine months ended September 30, 2012, Income tax expense decreased $8.4 million, or 29%, and $29.4 million, or 42%, respectively, as compared to 2011 primarily due to decreased pre-tax income, partially offset by increased state income taxes.

RESULTS OF OPERATIONS BY SEGMENT – DPL

DPL's two segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its competitive retail electric service subsidiaries. These segments are discussed further below:

Utility Segment

The Utility segment is comprised of **DP&L's** electric generation, transmission and distribution businesses which generate and sell electricity to residential, commercial, industrial and governmental customers. Electricity for the segment's 24-county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers who are located in a 6,000 square mile area of West Central Ohio. **DP&L** also sells electricity to DPLER and any excess energy and capacity is sold into the wholesale market. **DP&L's** transmission and distribution businesses are subject to rate regulation by federal and state regulators while rates for its generation business are deemed competitive under Ohio law.

Competitive Retail Segment

The Competitive Retail segment is comprised of the DPLER and MC Squared competitive retail electric service businesses which sell retail electric energy under contract to residential, commercial, industrial and governmental customers who have selected DPLER or MC Squared as their alternative electric supplier. The Competitive Retail segment sells electricity to approximately 175,000 customers currently located throughout Ohio and Illinois. MC Squared, a Chicago-based retail electricity supplier, serves more than 101,000 customers in Northern Illinois. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. **DP&L** sells power to DPLER and MC Squared under wholesale agreements. Under these agreements, intercompany sales from **DP&L** to DPLER and MC Squared are based on fixed-price contracts for each DPLER or MC Squared customer. The price approximates market prices for wholesale power at the inception of each customer's contract. The Competitive Retail segment has no transmission or generation assets. The operations of the Competitive Retail segment are not subject to cost-of-service rate regulation by federal or state regulators.

Other

Included within Other are other businesses that do not meet the GAAP requirements for separate disclosure as reportable segments as well as certain corporate costs which include amortization of intangibles recognized in conjunction with the Merger and interest expense on **DPL's** debt.

Management evaluates segment performance based on gross margin.

See Note 14 of Notes to **DPL's** Condensed Consolidated Financial Statements for further discussion of **DPL's** reportable segments.

The following table presents **DPL's** gross margin by business segment:

	Three Months Ended	Increase

$ in millions	September 30, 2012 Successor	2011 Predecessor	(Decrease) 2012 vs. 2011
Utility	$ **238.8**	$ 232.9	$ 5.9
Competitive retail	**22.1**	17.2	4.9
Other	**(16.0)**	11.3	(27.3)
Adjustments and eliminations	**(0.8)**	(1.1)	0.3
Total consolidated	$ **244.1**	$ 260.3	$ (16.2)

	Nine Months Ended September 30, 2012 Successor	2011 Predecessor	Increase (Decrease) 2012 vs. 2011
Utility	$ **666.6**	$ 669.7	$ (3.1)
Competitive retail	**51.9**	46.0	5.9
Other	**(44.3)**	35.3	(79.6)
Adjustments and eliminations	**(2.5)**	(3.1)	0.6
Total consolidated	$ 671.7	$ 747.9	$ (76.2)

The financial condition, results of operations and cash flows of the Utility segment are identical in all material respects, and for both periods presented, to those of **DP&L** which are included in this Form 10-Q. We do not believe that additional discussions of the financial condition and results of operations of the Utility segment would enhance an understanding of this business since these discussions are already included under the **DP&L** discussions below.

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Income Statement Highlights – Competitive Retail Segment

$ in millions	Three Months Ended September 30, 2012 Successor	2011 Predecessor	Increase (Decrease) 2012 vs. 2011
Revenues:			
Retail	$ **147.2**	$ 119.5	$ 27.7
RTO and other	**(1.7)**	(0.9)	(0.8)
Total revenues	**145.5**	118.6	26.9
Cost of revenues:			
Purchased power	**123.4**	101.4	22.0
Gross margins *(a)*	**22.1**	17.2	4.9
Operation and maintenance expense	**5.4**	4.5	0.9
Other expenses	**0.8**	0.7	0.1
Total expenses	**6.2**	5.2	1.0
Earnings before income tax	**15.9**	12.0	3.9
Income tax expense	**5.9**	4.2	1.7
Net income	$ **10.0**	$ 7.8	$ 2.2
Gross margin as a percentage of revenues	**15%**	15%	

(a) *For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.*

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$ in millions	Nine Months Ended September 30, 2012 Successor	2011 Predecessor	Increase (Decrease) 2012 vs. 2011
Revenues:			

Retail	$ 367.4	$ 319.1	$ 48.3
RTO and other	0.1	(4.5)	4.6
Total revenues	367.5	314.6	52.9
Cost of revenues:			
Purchased power	315.6	268.6	47.0
Gross margins *(a)*	51.9	46.0	5.9
Operation and maintenance expense	16.4	10.6	5.8
Other expenses	2.2	1.7	0.5
Total expenses	18.6	12.3	6.3
Earnings before income tax	33.3	33.7	(0.4)
Income tax expense	15.8	14.1	1.7
Net income	$ 17.5	$ 19.6	$ (2.1)
Gross margin as a percentage of revenues	14%	15%	

(a) *For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.*

Competitive Retail Segment – Revenue

For the three months ended September 30, 2012, the segment's retail revenues increased $27.7 million, or 23%, as compared to 2011. The increase was primarily due to increased retail sales volume from **DP&L's** retail customers switching their electric service to DPLER and customer switching in Illinois. Increased competition in the competitive retail electric service business in the state of Ohio has resulted in many of **DP&L's** retail customers switching their retail electric service to DPLER or other CRES suppliers. Primarily as a result of the customer switching discussed above, the Competitive Retail segment sold approximately 2,484 million kWh of power to approximately 175,000 customers for the three months ending September 30, 2012 compared to approximately 1,871 million kWh of power to more than 25,000 customers during the same period of 2011.

For the nine months ended September 30, 2012, the segment's retail revenues increased $48.3 million, or 15%, as compared to 2011. The increase was primarily due to a $26.9 million increase in retail revenue from MC Squared which was purchased on February 28, 2011 combined with increased retail sales volume from **DP&L's** retail customers switching their electric service to DPLER. Increased competition in the competitive retail electric service business in the state of Ohio has resulted in many of **DP&L's** retail customers switching their retail electric service to DPLER or other CRES suppliers. Similar competition in Illinois has resulted in favorable increases in MC Squared's number of retail customers due to switching. The increased sales volume from switching and from MC Squared was partially offset by unfavorable weather conditions resulting in a 22% decrease in the number of heating degree days during the period in 2012 compared to 2011. Primarily as a result of the customer switching discussed above, the Competitive Retail segment sold approximately 6,100 million kWh of power to approximately 175,000 customers for the nine months ending September 30, 2012 compared to approximately 5,011 million kWh of power to more than 25,000 customers during the same period of 2011.

Competitive Retail Segment – Purchased Power

For the three months ended September 30, 2012, the Competitive Retail segment purchased power increased $22.0 million, or 22%, as compared to 2011 due to higher purchased power volumes required to satisfy an increase in customer base resulting from customer switching. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM.

For the nine months ended September 30, 2012, the Competitive Retail segment purchased power increased $47.0 million, or 17%, as compared to 2011 due to higher purchased power volumes required to satisfy an increase in customer base resulting from customer switching and power purchased for MC Squared customers for all nine months in 2012 versus seven months in 2011. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM.

Intercompany sales from **DP&L** to DPLER are based on fixed-price contracts for each DPLER customer; the price approximates market prices for wholesale power at the inception of each customer's contract.

Competitive Retail Segment – Operation and Maintenance

For the three months ended September 30, 2012, DPLER's operation and maintenance expenses included employee-related expenses, accounting, information technology, payroll, legal and other administration expenses. The higher operation and maintenance expense in 2012 as compared to 2011 is reflective of increased marketing and customer maintenance costs associated with the increased sales volume and number of customers.

For the nine months ended September 30, 2012, DPLER's operation and maintenance expenses included employee-related expenses, accounting, information technology, payroll, legal and other administration expenses. The higher operation and maintenance expense in 2012 as compared to 2011 is reflective of increased marketing and customer maintenance costs associated with the increased sales volume and number of customers as well as the purchase of MC Squared.

Competitive Retail Segment – Income Tax Expense

For the three and nine months ended September 30, 2012, the segment's income tax expense increased $1.7 million and $1.7 million, respectively, compared to the same periods in 2011 due to increased state income tax expenses.

RESULTS OF OPERATIONS – DP&L

Income Statement Highlights – DP&L

$ in millions	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenues:				
Retail	$ **240.9**	$ 277.8	$ **696.3**	$ 786.2
Wholesale	**150.9**	122.3	**351.2**	333.2
RTO revenues	**33.5**	20.7	**69.2**	59.2
RTO capacity revenues	**4.7**	31.7	**58.7**	120.6
Mark-to-market (gains)/losses	**(3.2)**	-	**(2.4)**	-
Total revenues	**426.8**	452.5	**1,173.0**	1,299.2
Cost of revenues:				
Fuel costs	**114.7**	116.8	**272.1**	303.5
Gains from sale of coal	**3.1**	(3.9)	**8.4**	(6.8)
Mark-to-market (gains)/losses	**(9.7)**	11.1	**(8.2)**	15.0
Net fuel	**108.1**	124.0	**272.3**	311.7
Purchased power	**42.4**	28.5	**99.0**	95.2
RTO charges	**29.7**	33.5	**74.5**	90.2
RTO capacity charges	**5.7**	33.6	**58.3**	132.5
Mark-to-market (gains)/losses	**2.1**	-	**2.3**	(0.1)
Total purchased power	**79.9**	95.6	**234.1**	317.8
Total cost of revenues	**188.0**	219.6	**506.4**	629.5
Gross margins *(a)*	$ **238.8**	$ 232.9	$ **666.6**	$ 669.7
Gross margin as a percentage of revenues	**56%**	51%	**57%**	52%
Operating Income	$ **3.6**	$ 100.0	$ **125.6**	$ 245.1

(a) *For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.*

(b)

DP&L – Revenues

Retail customers, especially residential and commercial customers, consume more electricity on warmer and colder days. Therefore, **DP&L's** retail sales volume is impacted by the number of heating and cooling degree days occurring during a year. Since **DP&L** plans to utilize its internal generating capacity to supply its retail customers' needs first, increases in retail demand will decrease the volume of internal generation available to be sold in the wholesale market and vice versa.

The wholesale market covers a multi-state area and settles on an hourly basis throughout the year. Factors impacting **DP&L's** wholesale sales volume each hour of the year include: wholesale market prices, **DP&L's** retail demand, retail demand elsewhere throughout the entire wholesale market area, **DP&L** and non-**DP&L** plants' availability to sell into the wholesale market and weather conditions across the multi-state region. **DP&L's** plan is to make wholesale sales when market prices allow for the economic operation of its generation facilities that are not being utilized to meet its retail demand.

The following table provides a summary of changes in revenues from the prior period:

$ in millions	Three Months Ended September 30, 2012 vs. 2011	Nine Months Ended September 30, 2012 vs. 2011
Retail		
Rate	$ (7.7)	$ (16.5)
Volume	(27.2)	(71.3)
Other miscellaneous	(2.0)	(2.1)
Total retail change	(36.9)	(89.9)
Wholesale		
Rate	(20.8)	(17.2)
Volume	49.4	35.2
Total wholesale change	28.6	18.0
RTO capacity & other		
RTO capacity and other revenues	(14.2)	(51.9)
Other		
Unrealized MTM	(3.2)	(2.4)
Total other revenue	(3.2)	(2.4)
Total revenues change	$ (25.7)	$ (126.2)

For the three months ended September 30, 2012, Revenues decreased $25.7 million, or 6%, to $426.8 million from $452.5 million in the prior year. This decrease was primarily the result of lower average retail and wholesale rates, lower retail sales volumes and decreased RTO capacity and other revenues, offset slightly by increased wholesale sales volume. The revenue components for the three months ended September 30, 2012 are further discussed below:

- Retail revenues decreased $36.9 million primarily due to a 10% decrease in retail sales volumes compared to the prior year which was largely a result of customer switching due to increased levels of competition to provide transmission and generation services in our service territory. This decrease in sales volume was partially offset by improved economic conditions. Weather during the three months was slightly unfavorable with a 12% decrease in the number of heating degree days to 110 days from 124 days in 2011 as well as a 2% decrease in the number of cooling degree days to 825 days from 839 days in 2011. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to DPLER, an affiliated CRES provider, **DP&L** continued to provide distribution services to those customers within its service territory. Average retail rates decreased 3% overall primarily as a result of customers switching from **DP&L** to DPLER. The remaining distribution services provided by **DP&L** were billed at a lower rate resulting in a reduction of total average retail rates. The decrease in average retail rates resulting from customers switching was partially offset by the implementation of the fuel and energy efficiency riders, increased TCRR and RPM riders, and the incremental effect of the recovery of costs under the EIR. The above resulted in an unfavorable $27.2 million retail sales volume variance and an unfavorable $7.7 million retail price variance.
- Wholesale revenues increased $28.6 million primarily as a result of a 40% increase in wholesale sales volume which was largely a result the effect of customer switching discussed in the immediately preceding paragraph. **DP&L** records wholesale revenues from its sale of transmission and generation services to DPLER associated with these switched customers. These resulted in a favorable $49.4 million wholesale volume variance offset by a $20.8 million unfavorable wholesale price variance.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $14.2 million compared to the same period in 2011. This decrease in RTO capacity and other revenues was primarily the result of a $27.0 million decrease in revenues realized

from the PJM capacity auction, offset by a slight increase of $12.8 million in transmission and congestion revenues as a result of receiving the SECA settlement.

For the nine months ended September 30, 2012, Revenues decreased $126.2 million, or 10%, to $1,173.0 million from $1,299.2 million in the prior year. This decrease was primarily the result of lower average retail and wholesale rates, lower retail sales volumes and decreased RTO capacity and other revenues, partially offset by higher wholesale sales volume. The revenue components for the nine months ended September 30, 2012 are further discussed below:

- Retail revenues decreased $89.9 million primarily due to a 9% decrease in retail sales volumes compared to those in the prior year largely due to unfavorable weather conditions. The unfavorable weather conditions resulted in a 22% decrease in the number of heating degree days to 2,828 days from 3,604 days in 2011 offset slightly by a 9% increase in the number of cooling degree days to 1,255 days from 1,158 days in 2011. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to DPLER, an affiliated CRES provider, **DP&L** continued to provide distribution services to those customers within its service territory. The average retail rates decreased 2% overall primarily as a result of customers switching from **DP&L** to DPLER. The remaining distribution services provided by **DP&L** were billed at a lower rate resulting in a reduction of total average retail rates. The decrease in average retail rates resulting from customers switching was partially offset by the implementation of the fuel and energy efficiency riders, increased TCRR and RPM riders, and the incremental effect of the recovery of costs under the EIR. The above resulted in an unfavorable $71.3 million retail sales volume variance and an unfavorable $16.5 million retail price variance.
- Wholesale revenues increased $18.0 million primarily as a result of a 10% increase in wholesale sales volume which was largely a result of the effect of customer switching discussed in the immediately preceding paragraph. **DP&L** records wholesale revenues from its sale of transmission and generation services to DPLER associated with these switched customers. This increase was partially offset by a 5% decrease in average wholesale sales prices. This resulted in a favorable $35.2 million wholesale volume variance offset partially by a $17.2 million unfavorable wholesale price variance.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $51.9 million compared to the same period in 2011. This decrease in RTO capacity and other revenues was primarily the result of a $61.9 million decrease in revenues realized from the PJM capacity auction offset by an increase of $10.0 million in transmission and congestion revenues, partially offset by the receipt of the SECA settlement.

DP&L – Cost of Revenues

For the three months ended September 30, 2012:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $15.9 million, or 13%, during the quarter ended September 30, 2012 compared to the same period in 2011. This decrease was largely due to unrealized MTM gains of $9.7 million for the three months ended September 30, 2012 versus $11.1 million of MTM losses during the same period in 2011. Also contributing to this decrease was a $2.1 million decrease in fuel costs driven by a 3% decrease in the volume of generation at our plants. Partially offsetting the decreases were $3.1 million in realized losses from **DP&L's** sale of coal, compared to $3.9 million of realized gains during the same period in 2011.
- Net purchased power decreased $15.7 million, or 16%, compared to the same period in 2011 due largely to a $31.7 million decrease in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This decrease included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Partially offsetting this decrease was an increase in purchased power costs of $13.9 million, or 49%, compared to the same period in 2011, as well as an increase in unrealized MTM losses of $2.1 million. The increase in purchased power costs was driven by an increase in purchased power volumes of 87% partially offset by a decrease in purchased power prices of approximately 21%. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.

For the nine months ended September 30, 2012:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $39.4 million, or 13%, during the nine months ended September 30, 2012 compared to the same period in 2011. This decrease was largely due to a $31.4 million decrease in fuel costs driven by a 12% decrease in the volume of generation at our plants. Also contributing to the decrease were realized losses from **DP&L's** sale of coal of $8.4 million for the nine months ended September 30, 2012 versus $6.8 million in realized gains during the same period in 2011. Partially offsetting the decreases were $8.2 million in unrealized MTM gains, compared to $15.0 million of unrealized MTM losses during the same period in 2011.
- Net purchased power decreased $83.7 million, or 26%, compared to the same period in 2011 due largely to an $89.9 million decrease in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This decrease included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Partially offsetting this decrease was an increase in purchased power costs of $3.8 million, or 4%, compared to the same period in 2011, as well as an increase in unrealized MTM losses of $2.4 million. The increase in purchased power costs was driven by an increase in purchased power volumes of 36%, partially offset by a decrease in purchased power prices of approximately 23%. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.

DP&L – Operation and Maintenance

The following table provides a summary of changes in operation and maintenance expense from the prior period.

$ in millions	Three Months Ended September 30, 2012 vs. 2011	Nine Months Ended September 30, 2012 vs. 2011
Low-income payment program [1]	$ 5.7	$ 16.1
Energy efficiency program [1]	4.0	8.8
Maintenance of overhead transmission and distribution lines	2.5	(3.9)
Generating facilities operating and maintenance expense	2.0	3.4
Pension related expense	2.8	4.5
Deferred compensation	(0.6)	(2.6)
Other, net	7.0	5.8
Total change in operation and maintenance expense	$ 23.4	$ 32.1

(1) There is a corresponding increase in Revenues associated with this program resulting in no impact to Net Income.

For the three months ended September 30, 2012, Operation and maintenance expense increased $23.4 million, or 29%, compared to the same period in 2011. This variance was primarily the result of:

- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased expenses relating to energy efficiency programs that were put in place for our customers,
- increased maintenance of overhead transmission and distribution lines due to the derecho storm in late June, partially offset by decreased non-storm related expenses,
- increased expenses for generating facilities largely due to the length and timing of planned outages at jointly owned production units relative to the same period in 2011, and
- higher pension expenses primarily related to a one-time SERP settlement charge of $0.6 million which was recorded as a July 2012 lump-sum payment to a SERP participant triggered by settlement accounting for the SERP as well as changes in plan assumptions, specifically a lower discount rate and lower expected rate of return on plan assets.

These increases were partially offset by:

- decreased expenses related to deferred compensation arrangements primarily due to fewer equity awards in the current periods.

For the nine months ended September 30, 2012, Operation and maintenance expense increased $32.1 million, or 12%, compared to the same period in 2011. This variance was primarily the result of:

- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased expenses relating to energy efficiency programs that were put in place for our customers,
- increased expenses for generating facilities largely due to the length and timing of planned outages at jointly owned production units relative to the same period in 2011, and
- higher pension expenses primarily related to a one-time SERP settlement charge of $0.6 million which was recorded as a July 2012 lump-sum payment to a SERP participant triggered by settlement accounting for the SERP as well as changes in plan assumptions, specifically a lower discount rate and lower expected rate of return on plan assets.

These increases were partially offset by:

- decreased expenses related to the maintenance of overhead transmission and distribution lines primarily as a result of storms, including a significant ice storm in February 2011, and
- decreased expenses related to deferred compensation arrangements primarily due to fewer equity awards in the current periods.

On August 10, 2012, **DP&L** filed with the PUCO for an accounting order for permission to defer operation and maintenance costs as a result of damage caused by storms occurring during the final weekend of June 2012. The deferral request is for distribution expense incurred for these storms. The deferral would earn a return equal to the carrying cost of debt (5.86%) until these costs are recovered from customers. On October 19, 2012, **DP&L** amended its filing to change the method of calculating the deferral. If PUCO approval is received, **DP&L** will defer approximately $5.8 million of costs associated with these storms.

DP&L – Depreciation and Amortization

For the three and nine months ended September 30, 2012, Depreciation and amortization expense increased $2.7 million and $7.0 million, respectively, as compared to 2011. The increase primarily reflected the impact of investments in plant and equipment during the nine months ended September 30, 2012.

DP&L – General Taxes

For the three and nine months ended September 30, 2012, General taxes decreased $4.6 million, or 24%, and $3.5 million, or 6%, respectively, as compared to 2011. This decrease was primarily the result of the release of a property tax reserve in 2012 related to purchase accounting property revaluations. Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, these taxes are accounted for on a net basis and are recorded as a reduction in Revenues for presentation in accordance with AES policy. The 2011 amounts were reclassified to conform to this presentation.

DP&L – Interest Expense

Interest expense recorded during the three and nine months ended September 30, 2012 did not fluctuate significantly from that recorded during the three and nine months ended September 30, 2011.

DP&L – Income Tax Expense

For the three and nine months ended September 30, 2012, Income tax expense decreased $20.3 million, or 76%, and decreased $29.9 million, or 43%, respectively, as compared to 2011. The three month increase was primarily due to the effect of estimate-to-actual income tax provision adjustments and the nine month decrease was primarily due to decreased pre-tax income.

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL REQUIREMENTS

DPL's financial condition, liquidity and capital requirements include the results of its principal subsidiary **DP&L**. All material intercompany accounts and transactions have been eliminated in consolidation. The following table provides a summary of the cash flows for **DPL** and **DP&L**:

DPL $ in millions	**Nine Months Ended September 30, 2012**	Nine Months Ended September 30, 2011
	Successor	**Predecessor**
Net cash from operating activities	$ **249.7**	$ 273.9
Net cash from investing activities	**(163.5)**	(88.0)
Net cash from financing activities	**(54.1)**	(242.3)

Net change		32.1		(56.4)
Cash and cash equivalents at beginning of period		173.5		124.0
Cash and cash equivalents at end of period	$	205.6	$	67.6

DP&L $ in millions		**Nine Months Ended September 30, 2012**		Nine Months Ended September 30, 2011
Net cash from operating activities	$	299.8	$	294.2
Net cash from investing activities		(166.9)		(145.9)
Net cash from financing activities		(145.7)		(180.6)
Net change		(12.8)		(32.3)
Cash and cash equivalents at beginning of period		32.2		54.0
Cash and cash equivalents at end of period	$	19.4	$	21.7

The significant items that have affected the cash flows for **DPL** and **DP&L** are discussed in greater detail below:

Net cash provided by operating activities

The revenue from our energy business continues to be the principal source of cash from operating activities while our primary uses of cash include payments for fuel, purchased power, operation and maintenance expenses, interest and taxes.

DPL – Net cash from operating activities

DPL's Net cash from operating activities for the nine months ended September 30, 2012 and 2011 can be summarized as follows:

$ in millions		**Nine Months Ended September 30, 2012**		Nine Months Ended September 30, 2011
		Successor		**Predecessor**
Net cash from operating activities				
Net (loss) / income	$	(1,777.3)	$	142.3
Depreciation and amortization		152.6		106.0
Deferred income taxes		(10.5)		70.5
Charge for early redemption of debt		-		15.3
Goodwill impairment		1,850.0		-
Contribution to pension plan		-		(40.0)
Accrued interest		25.2		(3.1)
Deferred regulatory costs, net		2.7		7.9
Prepaid taxes		0.6		(27.0)
Other		6.4		2.0
Net cash from operating activities	$	249.7	$	273.9

For the nine months ended September 30, 2012, Net cash provided by operating activities was primarily a result of Net loss adjusted for non-cash depreciation and amortization and the goodwill impairment. Other represents items that had a current period cash flow impact and includes changes in working capital and other future rights or obligations to receive or to pay cash. These items are primarily affected by, among other factors, the timing of when cash payments are made for fuel, purchased power, operating costs, taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances. Accrued interest relates primarily to the $1,250.0 million of debt that was assumed by **DPL** at the merger date and the timing of interest payments.

For the nine months ended September 30, 2011, Net cash provided by operating activities was primarily a result of earnings from continuing operations adjusted for non-cash depreciation and amortization, combined with the following significant transactions:

- A $70.5 million increase to deferred income taxes primarily as a result of depreciation as well as pension contributions, financial transaction losses and other temporary differences arising from routine changes in balance sheet accounts giving rise to deferred taxes.
- A $15.3 million charge for the early redemption of DPL Capital Trust II securities.

- A **DP&L** discretionary contribution of $40.0 million to the defined benefit pension plan in February 2011.

DP&L – Net cash from operating activities

DP&L's Net cash from operating activities for the nine months ended September 30, 2012 and 2011 can be summarized as follows:

$ in millions		**Nine Months Ended September 30, 2012**		Nine Months Ended September 30, 2011
Net cash from operating activities				
Net income	$	**58.3**	$	147.4
Depreciation and amortization		**107.3**		100.3
Deferred income taxes		**(3.4)**		56.1
Fixed asset impairment		**80.8**		-
Recognition of deferred SECA revenue		**(17.8)**		-
Contribution to pension plan		**-**		(40.0)
Increase in current assets		**41.1**		17.4
Accrued interest		7.4		7.4
Deferred regulatory costs, net		**2.4**		7.9
Prepaid taxes		**0.8**		(11.5)
Other		**22.9**		9.2
Net cash from operating activities	$	**299.8**	$	294.2

For the nine months ended September 30, 2012 and 2011, the significant components of **DP&L's** Net cash provided by operating activities are similar to those discussed under **DPL's** Net cash provided by operating activities above.

DPL – Net cash from investing activities

DPL's Net cash from investing activities for the nine months ended September 30, 2012 and 2011 can be summarized as follows:

$ in millions		**Nine Months Ended September 30, 2012**		Nine Months Ended September 30, 2011
		Successor		**Predecessor**
Net cash from investing activities				
Other plant acquisitions, net	$	**(155.6)**	$	(132.8)
Environmental and renewable energy capital expenditures		**(7.5)**		(8.5)
Purchase of MC Squared		**-**		(8.3)
Increase in restricted cash		**(0.4)**		(9.1)
Sales / (purchases) of short-term investments, net		**-**		69.2
Other		**-**		1.5
Net cash from investing activities	$	**(163.5)**	$	(88.0)

For the nine months ended September 30, 2012, **DPL's** cash used for investing activities reflects assets acquired at our generation plants.

For the nine months ended September 30, 2011, **DPL** cash used for investing activities was primarily for assets acquired at our generation plants. Additionally, **DPL**, on behalf of DPLER, made a cash payment of approximately $8.3 million to acquire MC Squared. Also during the nine months ended September 30, 2011, **DPL** redeemed $70.9 million of short-term investments mostly comprised of VRDN securities as well as purchased an additional $1.7 million of short-term investments during the same period. These securities have variable coupon rates that are typically reset weekly relative to various short-term rate indices. **DPL** can tender

these VRDN securities for sale upon notice to the broker and receive payment for the tendered securities within seven days.

DP&L – Net cash from investing activities

DP&L's Net cash from investing activities for the nine months ended September 30, 2012 and 2011 can be summarized as follows:

$ in millions	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net cash from investing activities		
Other plant acquisitions, net	$ (154.2)	$ (131.4)
Environmental and renewable energy capital expenditures	(7.5)	(8.5)
Increase in restricted cash	(5.2)	(7.4)
Other	-	1.4
Net cash from investing activities	$ (166.9)	$ (145.9)

For the nine months ended September 30, 2012 and 2011, the significant components of **DP&L's** Net cash used for investing activities are similar to those discussed under **DPL's** Net cash used for investing activities above with the exception of the short-term investing activity.

DPL – Net cash from financing activities

DPL's Net cash from financing activities for the nine months ended September 30, 2012 and 2011 can be summarized as follows:

$ in millions	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	Successor	Predecessor
Net cash from financing activities		
Dividends paid on common stock	$ (45.0)	$ (113.8)
Payment to former warrant holders	(9.0)	-
Issuance of long-term debt	-	300.0
Retirement of long-term debt	(0.1)	(297.4)
Early redemption of long-term debt, including premium	-	(134.2)
Payment of MC Squared debt	-	(13.5)
Exercise of warrants	-	14.7
Exercise stock options	-	1.9
Other	-	-
Net cash from financing activities	$ (54.1)	$ (242.3)

For the nine months ended September 30, 2012, **DPL** paid common stock dividends of $45.0 million to its parent, partially offset by contributions to additional paid-in capital from its parent, AES. **DPL** also paid $9.0 million to former warrant holders, the payment of which represents the difference between the exercise price of $21.00 per share and the $30.00 per share paid by AES in the Merger.

For the nine months ended September 30, 2011, **DPL** paid common stock dividends of $113.8 million. In addition, DPL issued $300.0 million of new long-term debt and paid $297.4 million to retire existing long-term debt. It also paid $134.2 million for the purchase of the DPL Capital Trust II capital securities, of which $122.0 million related to the capital securities and an additional $12.2 million related to the premium paid on the purchase. **DPL** also paid down the debt of MC Squared which was acquired in February 2011.

DP&L – Net cash from financing activities

DP&L's Net cash from financing activities for the nine months ended September 30, 2012 and 2011 can be summarized as follows:

$ in millions	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011

Net cash from financing activities		
Dividends paid on common stock	$ **(145.0)**	$ (180.0)
Other	**(0.7)**	(0.6)
Net cash from financing activities	$ **(145.7)**	$ (180.6)

For the nine months ended September 30, 2012, **DP&L's** Net cash used for financing activities primarily relates to $145.0 million in dividends paid to **DPL**.

For the nine months ended September 30, 2011, **DP&L's** Net cash used for financing activities primarily relates to $180.0 million in dividends paid to **DPL**.

Liquidity

We expect our existing sources of liquidity to remain sufficient to meet our anticipated operating needs. Our business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and carrying costs, potential margin requirements for retail operations and dividend payments. For 2012, and in subsequent years, we expect to satisfy these requirements with a combination of cash from operations and funds from the capital markets as our internal liquidity needs and market conditions warrant. We also expect that the borrowing capacity under bank credit facilities will continue to be available to manage working capital requirements during those periods.

At the filing date of this quarterly report on Form 10-Q, **DP&L** has access to $400.0 million of short-term financing under two revolving credit facilities. The first facility, established in August 2011, is for $200.0 million, expires in August 2015 and has eight participating banks, with no bank having more than 22% of the total commitment. **DP&L** also has the option to increase the potential borrowing amount under the first facility by $50.0 million. The second facility, established in April 2010, is for $200.0 million and expires in April 2013. A total of five banks participate in this facility, with no bank having more than 35% of the total commitment. **DP&L** also has the option to increase the potential borrowing amount under the second facility by $50.0 million.

At the filing date of this quarterly report on Form 10-Q, **DPL** has access to $75.0 million of short-term financing under a revolving credit facility established in August 2011. This facility expires in August 2014 and has seven participating banks with no bank having more than 32% of the total commitment. The size of the facility was reduced from the original $125.0 million to the current $75.0 million as part of an amendment dated October 19, 2012 that was negotiated between **DPL** and the syndicated bank group. See "Debt Covenants" following for more information on the amendment.

$ in millions	Type	Maturity	Commitment	Amounts available as of October 19, 2012
DP&L	Revolving	August 2015	$ 200.0	$ 200.0
DP&L	Revolving	April 2013	200.0	200.0
DPL Inc.	Revolving	August 2014	75.0	75.0
			$ 475.0	$ 475.0

Each **DP&L** revolving credit facility has a $50.0 million letter of credit sublimit. The entire **DPL** revolving credit facility amount is available for letter of credit issuances. As of September 30, 2012 and through the date of filing this quarterly report on Form 10-Q, there were no letters of credit issued and outstanding on the revolving credit facilities.

Cash and cash equivalents for **DPL** and **DP&L** amounted to $205.6 million and $19.4 million, respectively, at September 30, 2012. At that date, neither **DPL** nor **DP&L** had any short-term investments that were not included in cash and cash equivalents.

On February 23, 2011, **DPL** purchased and retired $122.0 million principal amount of DPL Capital Trust II 8.125% trust preferred securities. As part of this transaction, **DPL** paid a $12.2 million, or 10%, premium. Debt issuance costs and unamortized debt discount associated with this transaction, totaling $3.1 million, were also recognized in February 2011.

Capital Requirements

Planned construction additions for 2012 relate primarily to new investments in and upgrades to **DP&L's** power plant equipment and transmission and distribution system. Capital projects are subject to continuing review and are revised in light of changes in financial and economic conditions, load forecasts, legislative and regulatory developments and changing environmental standards, among other factors.

DPL is projecting to spend an estimated $530.0 million in capital projects for the period 2012 through 2014, of which $515.0 million is projected to be spent by **DP&L**. Approximately $15.0 million of this projected amount is to enable **DP&L** to meet the recently revised reliability standards of NERC. **DP&L** is subject to the mandatory reliability standards of NERC and Reliability First Corporation (RFC), one of the eight NERC regions, of which **DP&L** is a member. NERC has changed the definition of the Bulk Electric System (BES) to include 100 kV and above facilities, thus expanding the facilities to which the reliability standards apply. **DP&L's** 138 kV facilities were previously not subject to these reliability standards. Accordingly, **DP&L** anticipates spending approximately $72.0 million within the next 5 years to reinforce its 138 kV system to comply with these new NERC standards. Our ability to complete capital projects and the reliability of future service will be affected by our financial condition, the availability of internal funds and the reasonable cost of external funds. We expect to finance our construction additions with a combination of cash on hand, short-term financing, long-term debt and cash flows from operations.

Debt Covenants

As mentioned above, **DPL** has access to $75.0 million of short-term financing under its revolving credit facility and has borrowed $425.0 million under its term loan facility.

Each of these facilities has two financial covenants, one of which was changed as part of amendments, dated October 19, 2012, to the facilities negotiated between **DPL** and the syndicated bank groups. The first financial covenant, originally a Total Debt to Capitalization ratio, was changed, effective September 30, 2012, to a Total Debt to EBITDA ratio. The Total Debt to EBITDA ratio is calculated, at the end of each fiscal quarter, by dividing total debt at the end of the current quarter by consolidated EBITDA for the four prior fiscal quarters. The ratio is not to exceed 7.0 to 1.0 for the fiscal quarter ending September 30, 2012; it then steps up to not exceed 7.75 to 1.0 for the fiscal quarter ending March 31, 2013; it then steps up to not exceed 8.0 to 1.0 for the fiscal quarter ending June 30, 2013; and finally it steps up to not exceed 8.25 to 1.0 for the fiscal quarter ending September 30, 2013 and thereafter. As of September 30, 2012, the first financial covenant was met with a ratio of 5.29 to 1.00.

The second financial covenant is an EBITDA to Interest Expense ratio. The EBITDA to Interest Expense ratio is calculated, at the end of each fiscal quarter, by dividing consolidated earnings before interest, taxes, depreciation and amortization (EBITDA) for the four prior fiscal quarters by the consolidated interest charges for the same period. The ratio requires **DPL's** consolidated EBITDA to consolidated interest expense to be not less than 2.50 to 1.00. As of September 30, 2012 the second covenant was met with a ratio of 4.40 to 1.00.

The amendments, dated October 19, 2012, to the facilities negotiated between **DPL** and the syndicated bank groups, restrict dividend payments from **DPL** to AES. The amendments also adjusted the cost of borrowing under the facilities.

Also mentioned above, **DP&L** has access to $400.0 million of short-term financing under its two revolving credit facilities. The following financial covenant is contained in each revolving credit facility: **DP&L's** total debt to total

capitalization ratio is not to exceed 0.65 to 1.00. As of September 30, 2012, this covenant was met with a ratio of 0.43 to 1.00. The above ratio is calculated as the sum of **DP&L's** current and long-term portion of debt, including its guarantee obligations, divided by the total of **DP&L's** shareholder's equity and total debt including guarantee obligations.

Debt Ratings

The following table outlines the debt ratings and outlook for each company, along with the effective dates of each rating and outlook for **DPL** and **DP&L**.

	DPL *(a)*	**DP&L** *(b)*	Outlook	Effective
Fitch Ratings	BB+	BBB+	Stable	November 2011
Moody's Investors Service	Ba1	A3	Stable	November 2011
Standard & Poor's Corp.	BB+	BBB+	CreditWatch Negative	April 2012

(a) Credit rating relates to DPL's Senior Unsecured debt.
(b) Credit rating relates to DP&L's Senior Secured debt.

Credit Ratings

The following table outlines the credit ratings (issuer/corporate rating) and outlook for each company, along with the effective dates of each rating and outlook for **DPL** and **DP&L**.

	DPL	**DP&L**	Outlook	Effective
Fitch Ratings	BB+	BBB-	Stable	November 2011
Moody's Investors Service	Ba1	Baa2	Stable	November 2011

Standard & Poor's Corp.	BBB-	BBB-	CreditWatch Negative	April 2012

Standard & Poor's recently put both **DPL** and **DP&L** on CreditWatch Negative reflecting the potential to lower the credit ratings of both entities in the near term pending greater clarity on the timing and transition to full market rates for **DP&L**. They have also revised their assessment of **DPL** and **DP&L's** business risk profiles to "strong" from "excellent" to reflect the increased competition in Ohio, the expected growth of the unregulated retail business and the increasing competitive pressure due to lower wholesale electric prices stressing profit margins.

If the rating agencies were to reduce our debt or credit ratings, our borrowing costs may increase, our potential pool of investors and funding resources may be reduced, and we may be required to post additional collateral under selected contracts. These events may have an adverse effect on our results of operations, financial condition and cash flows. In addition, any such reduction in our debt or credit ratings may adversely affect the trading price of our outstanding debt securities.

Off-Balance Sheet Arrangements

DPL – Guarantees

In the normal course of business, **DPL** enters into various agreements with its wholly owned subsidiaries, DPLE and DPLER, and its wholly owned subsidiary MC Squared, providing financial or performance assurance to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to these subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish these subsidiaries' intended commercial purposes. During the nine months ended September 30, 2012, **DPL** did not incur any losses related to the guarantees of these obligations and we believe it is unlikely that **DPL** would be required to perform or incur any losses in the future associated with any of the above guarantees.

At September 30, 2012, **DPL** had $24.4 million of guarantees to third parties, for future financial or performance assurance under such agreements, on behalf of DPLE, DPLER and MC Squared. The guarantee arrangements entered into by **DPL** with these third parties cover present and future obligations of DPLE, DPLER and MC

Squared to such beneficiaries and are terminable at any time by **DPL** upon written notice to the beneficiaries. The carrying amount of obligations for commercial transactions covered by these guarantees and recorded in our Condensed Consolidated Balance Sheets was $1.0 million at September 30, 2012.

DP&L owns a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. As of September 30, 2012, **DP&L** could be responsible for the repayment of 4.9%, or $78.8 million, of a $1,607.8 million debt obligation that features maturities ranging from 2013 to 2040. This would only happen if this electric generation company defaulted on its debt payments. As of September 30, 2012, we have no knowledge of such a default.

Commercial Commitments and Contractual Obligations

There have been no material changes, outside the ordinary course of business, to our commercial commitments and to the information disclosed in the contractual obligations table in our Form 10-K for the fiscal year ended December 31, 2011.

Also see Note 13 of Notes to **DPL's** Condensed Consolidated Financial Statements.

MARKET RISK

We are subject to certain market risks including, but not limited to, changes in commodity prices for electricity, coal, environmental emissions and gas, changes in capacity prices and fluctuations in interest rates. We use various market risk sensitive instruments, including derivative contracts, primarily to limit our exposure to fluctuations in commodity pricing. Our Commodity Risk Management Committee (CRMC), comprised of members of senior management, is responsible for establishing risk management policies and the monitoring and reporting of risk exposures relating to our **DP&L**-operated generation units. The CRMC meets on a regular basis with the objective of identifying, assessing and quantifying material risk issues and developing strategies to manage these risks.

Commodity Pricing Risk

Commodity pricing risk exposure includes the impacts of weather, market demand, increased competition and other economic conditions. To manage the volatility relating to these exposures at our **DP&L**-operated generation units, we use a variety of non-derivative and derivative instruments including forward contracts and futures contracts. These instruments are used principally for economic hedging purposes and none are held for trading purposes. Derivatives that fall within the scope of derivative accounting under GAAP must be recorded at their fair value and marked to market unless they qualify for cash flow hedge accounting. MTM gains and losses on derivative instruments that qualify for cash flow hedge accounting are deferred in AOCI until the forecasted transactions occur. We adjust the derivative instruments that do not qualify for cash flow hedging to fair value on a monthly basis and where applicable, we recognize a corresponding Regulatory asset for above-market costs or a Regulatory liability for below-market costs in accordance with regulatory accounting under GAAP.

The coal market has increasingly been influenced by both international and domestic supply and consumption, making the price of coal more volatile than in the past, and while we have substantially all of the total expected coal volume needed to meet our retail and firm wholesale sales requirements for 2012 under contract, sales requirements may change. The majority of the contracted coal is purchased at fixed prices. Some contracts provide for periodic adjustments. Fuel costs are affected by changes in volume and price and are driven by a number of variables including weather, the wholesale market price of power, certain provisions in coal contracts related to government imposed costs, counterparty performance and credit, scheduled outages and generation plant mix. To the extent we are not able to hedge against price volatility or recover increases through our fuel and purchased power recovery rider that began in January 2010, our results of operations, financial condition or cash flows could be materially affected.

For purposes of potential risk analysis, we use a sensitivity analysis to quantify potential impacts of market rate changes on the statements of results of operations. The sensitivity analysis represents hypothetical changes in market values that may or may not occur in the future.

Commodity Derivatives

To minimize the risk of fluctuations in the market price of commodities, such as coal, power and heating oil, we may enter into commodity-forward and futures contracts to effectively hedge the cost/revenues of the commodity. Maturity dates of the contracts are scheduled to coincide with market purchases/sales of the commodity. Cash proceeds or payments between us and the counter-party at maturity of the contracts are recognized as an adjustment to the cost of the commodity purchased or sold. We generally do not enter into forward contracts beyond thirty-six months.

A 10% increase or decrease in the market price of our heating oil forwards, NYMEX coal forwards or power forward contracts at September 30, 2012 would not have a significant effect on Net income.

Wholesale Revenues

Approximately 10% of **DPL's** and 36% of **DP&L's** electric revenues for the three months ended September 30, 2012 were from sales of excess energy and capacity in the wholesale market (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER). Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

Approximately 15% of **DPL's** and 33% of **DP&L's** electric revenues for the three months ended September 30, 2011 were from sales of excess energy and capacity in the wholesale market (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER). Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

Approximately 11% of **DPL's** and 35% of **DP&L's** electric revenues for the nine months ended September 30, 2012 were from sales of excess energy and capacity in the wholesale market (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER). Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

Approximately 17% of **DPL's** and 34% of **DP&L's** electric revenues for the nine months ended September 30, 2011 were from sales of excess energy and capacity in the wholesale market (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER). Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

The table below provides the effect on annual Net income as of September 30, 2012, of a hypothetical increase or decrease of 10% in the price per megawatt hour of wholesale power (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER), including the impact of a corresponding 10% change in the portion of purchased power used as part of the sale (note that the share of the internal generation used to meet the DPLER wholesale sale would not be affected by the 10% change in wholesale prices):

$ in millions	DPL	DP&L
Effect of 10% change in price per mWh	$ 6.1	$ 5.4

RPM Capacity Revenues and Costs

As a member of PJM, **DP&L** receives revenues from the RTO related to its transmission and generation assets and incurs costs associated with its load obligations for retail customers. PJM, which has a delivery year which runs from June 1 to May 31, has conducted auctions for capacity through the 2015/16 delivery year. The clearing prices for capacity during the PJM delivery periods from 2011/12 through 2015/16 are as follows:

	PJM Delivery Year				
	2011/12	2012/13	2013/14	2014/15	2015/16
Capacity clearing price ($/MW-day)	$ 110 134	$ 16	$ 28	$ 126	$ 136

Our computed average capacity prices by calendar year are reflected in the table below:

	Calendar Year				
	2011	2012	2013	2014	2015
Computed average capacity price ($/MW-day)	$ 137	$ 55	$ 23	$ 85	$ 132

Future RPM auction results are dependent on a number of factors, which include the overall supply and demand of generation and load, other state legislation or regulation, transmission congestion, and PJM's RPM business rules. The volatility in the RPM capacity auction pricing has had and will continue to have a significant impact on **DPL's** capacity revenues and costs. Although **DP&L** currently has an approved RPM rider in place to recover or repay any excess capacity costs or revenues, the RPM rider only applies to customers supplied under our SSO. Customer switching reduces the number of customers supplied under our SSO, causing more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation.

The table below provides estimates of the effect on annual net income as of September 30, 2012 of a hypothetical increase or decrease of $10/MW-day in the RPM auction price. The table shows the impact resulting from capacity revenue changes. We did not include the impact of a change in the RPM capacity costs since these costs will either be recovered through the RPM rider for SSO retail customers or recovered through the development of our overall energy pricing for customers who do not fall under the SSO. These estimates include the impact of the RPM rider and are based on the levels of customer switching experienced through September 30, 2012. As of September 30, 2012, approximately 48% of **DP&L's** RPM capacity revenues and costs were recoverable from SSO retail customers through the RPM rider.

$ in millions	DPL	DP&L
Effect of a $10/MW-day change in capacity auction pricing	$ 5.6	$ 4.3

Capacity revenues and costs are also impacted by, among other factors, the levels of customer switching, our generation capacity, the levels of wholesale revenues and our retail customer load. In determining the capacity price sensitivity above, we did not consider the impact that may arise from the variability of these other factors.

Fuel and Purchased Power Costs

DPL's and **DP&L's** fuel (including coal, gas, oil and emission allowances) and purchased power costs as a percentage of total operating costs in the nine months ended September 30, 2012 and 2011 were 38% and 42%, respectively. We have a significant portion of projected 2012 fuel needs under contract. The majority of our contracted coal is purchased at fixed prices although some contracts provide for periodic pricing adjustments. We may purchase SO_2 allowances for 2012; however, the exact consumption of SO_2 allowances will depend on market prices for power, availability of our generation units and the actual sulfur content of the coal burned. We may purchase some NOx allowances for 2012 depending on NOx emissions. Fuel costs are affected by changes in volume and price and are driven by a number of variables including weather, reliability of coal deliveries, scheduled outages and generation plant mix.

Purchased power costs depend, in part, upon the timing and extent of planned and unplanned outages of our generating capacity. We will purchase power on a discretionary basis when wholesale market conditions provide opportunities to obtain power at a cost below our internal generation costs.

Effective January 1, 2010, **DP&L** was allowed to recover its SSO retail customers' share of fuel and purchased power costs as part of the fuel rider approved by the PUCO. Since there has been an increase in customer switching, SSO customers currently represent approximately 36% of **DP&L's** total fuel costs. The table below provides the effect on annual net income as of September 30, 2012, of a hypothetical increase or decrease of 10% in the prices of fuel and purchased power, adjusted for the approximate 48% recovery:

$ in millions	DPL	DP&L
Effect of 10% change in fuel and purchased power	$ 21.3	$ 19.3

Interest Rate Risk

As a result of our normal investing and borrowing activities, our financial results are exposed to fluctuations in interest rates which we manage through our regular financing activities. We maintain both cash on deposit and investments in cash equivalents that may be affected by adverse interest rate fluctuations. **DPL** and **DP&L** have both fixed-rate and variable-rate long-term debt. **DPL's** variable-rate debt consists of a $425.0 million unsecured term loan with a syndicated bank group. The term loan interest rate fluctuates with changes in an underlying interest rate index, typically LIBOR. **DP&L's** variable-rate debt is comprised of publicly held pollution control bonds. The variable-rate bonds bear interest based on a prevailing rate that is reset weekly based on a comparable market index. Market indexes can be affected by market demand, supply, market interest rates and other economic conditions. See Note 6 of Notes to **DPL's** Condensed Consolidated Financial Statements and Note 6 to **DP&L's** Condensed Financial Statements.

We partially hedge against interest rate fluctuations by entering into interest rate swap agreements to limit the interest rate exposure on the underlying financing. As of September 30, 2012, we have entered into interest rate hedging relationships with an aggregate notional amount of $160.0 million related to planned future borrowing activities in calendar year 2013. The average interest rate associated with the $160.0 million aggregate notional amount interest rate hedging relationships is 3.8%. We are limiting our exposure to changes in interest rates since we believe the market interest rates at which we will be able to borrow in the future may increase. Any additional credit rating downgrades could affect our liquidity and further increase our cost of capital.

Principal Payments and Interest Rate Detail by Contractual Maturity Date

The carrying value of **DPL's** debt was $2,614.9 million at September 30, 2012, consisting of **DPL's** unsecured notes and unsecured term loan, along with **DP&L's** first mortgage bonds, tax-exempt pollution control bonds, capital leases, and the Wright-Patterson Air Force Base note. All of **DPL's** debt was adjusted to fair value at the Merger date according to FASC 805. The fair value of this debt at September 30, 2012 was $2,769.4 million, based on current market prices or discounted cash flows using current rates for similar issues with similar terms and remaining maturities. The following table provides information about **DPL's** debt obligations that are sensitive to interest rate changes:

DPL

	Twelve Months Ending September 30,						At September 30, 2012	
	2013	2014	2015	2016	2017	Thereafter	Carrying Value	Fair Value
Variable-rate debt	$ -	$ 425.0	$ -	$ -	$ -	$ 100.0	$ 525.0	$ 525.0
Average interest rate	0.0%	2.2%	0.0%	0.0%	0.0%	0.2%		
Fixed-rate debt [(a)]	$ 0.4	$ 489.6	$ 0.1	$ 0.1	$ 450.1	$ 1,149.6	2,089.9	2,244.4
Average interest rate	5.0%	5.1%	4.2%	4.2%	6.5%	6.6%		
Total							$ 2,614.9	$ 2,769.4

[(a)] *Fixed rate debt totals include unamortized debt discounts and premiums.*

The carrying value of **DP&L's** debt was $903.2 million at September 30, 2012, consisting of its first mortgage bonds, tax-exempt pollution control bonds, capital leases and the Wright-Patterson Air Force Base note. The fair value of this debt was $934.5 million, based on current market prices or discounted cash flows using current rates for similar issues with similar terms and remaining maturities. The following table provides information about **DP&L's** debt obligations that are sensitive to interest rate changes. Note that the **DP&L** debt was not revalued using push-down accounting as a result of the Merger.

DP&L

	Twelve Months Ending September 30,						At September 30, 2012	
	2013	2014	2015	2016	2017	Thereafter	Carrying Value	Fair Value
Variable-rate debt	$ -	$ -	$ -	$ -	$ -	$ 100.0	$ 100.0	$ 100.0

Average interest rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%		
Fixed-rate debt [a]	$ 0.4	$ 470.3	$ 0.1	$ 0.1	$ 0.1	$ 332.2	803.2	834.5
Average interest rate	5.0%	5.1%	4.2%	4.2%	4.2%	4.8%		
Total							$ 903.2	$ 934.5

[a] *Fixed rate debt totals include unamortized debt discounts and premiums.*

Debt maturities occurring in 2012 are discussed under FINANCIAL CONDITION, LIQUIDITY AND CAPITAL REQUIREMENTS.

Long-term Debt Interest Rate Risk Sensitivity Analysis

Our estimate of market risk exposure is presented for our fixed-rate and variable-rate debt at September 30, 2012 for which an immediate adverse market movement causes a potential material impact on our financial position, results of operations, or the fair value of the debt. We believe that the adverse market movement represents the hypothetical loss to future earnings and does not represent the maximum possible loss nor any expected actual loss, even under adverse conditions, because actual adverse fluctuations would likely differ. As of September 30, 2012, we did not hold any market risk sensitive instruments which were entered into for trading purposes.

DPL	At September 30, 2012		One percent
$ in millions	Carrying Value	Fair Value	interest rate risk
Long-term debt			
Variable-rate debt	$ 525.0	$ 525.0	$ 5.3
Fixed-rate debt	2,089.9	2,244.4	22.4
Total	$ 2,614.9	$ 2,769.4	$ 27.7

DP&L	At September 30, 2012		One percent
$ in millions	Carrying Value	Fair Value	interest rate risk
Long-term debt			
Variable-rate debt	$ 100.0	$ 100.0	$ 1.0
Fixed-rate debt	803.2	834.5	8.4
Total	$ 903.2	$ 934.5	$ 9.4

DPL's debt is comprised of both fixed-rate debt and variable-rate debt. In regard to fixed-rate debt, the interest rate risk with respect to **DPL's** long-term debt primarily relates to the potential impact a decrease of one percentage point in interest rates has on the fair value of **DPL's** $2,244.4 million of fixed-rate debt and not on **DPL's** financial condition or results of operations. On the variable-rate debt, the interest rate risk with respect to **DPL's** long-term debt represents the potential impact an increase of one percentage point in the interest rate has on **DPL's** results of operations related to **DPL's** $525.0 million variable-rate long-term debt outstanding as of September 30, 2012.

DP&L's interest rate risk with respect to **DP&L's** long-term debt primarily relates to the potential impact a decrease in interest rates of one percentage point has on the fair value of **DP&L's** $834.5 million of fixed-rate debt and not on **DP&L's** financial condition or **DP&L's** results of operations. On the variable-rate debt, the interest rate risk with respect to **DP&L's** long-term debt represents the potential impact an increase of one percentage point in the interest rate has on **DP&L's** results of operations related to **DP&L's** $100.0 million variable-rate long-term debt outstanding as of September 30, 2012.

Equity Price Risk

As of September 30, 2012, approximately 29% of the defined benefit pension plan assets were comprised of investments in equity securities and 71% related to investments in fixed income securities, cash and cash equivalents, and alternative investments. We use an investment adviser to assist in managing our investment portfolio. The market value of the equity securities was approximately $102.8 million at September 30, 2012. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $10.3 million reduction in fair value of the equity securities as of September 30, 2012.

Credit Risk

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. We limit our credit risk by assessing the creditworthiness of potential counterparties before entering into transactions with them and continue to evaluate their creditworthiness after transactions have been originated. We use the three leading corporate credit rating agencies and other current market-based qualitative and quantitative data to assess the financial strength of our counterparties on an ongoing basis. We may require various forms of credit assurance from our counterparties in order to mitigate credit risk.

CRITICAL ACCOUNTING ESTIMATES

DPL's Condensed Consolidated Financial Statements and **DP&L's** Condensed Financial Statements are prepared in accordance with U.S. GAAP. In connection with the preparation of these financial statements, our management is required to make assumptions, estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the related disclosure of contingent liabilities. These assumptions, estimates and judgments are based on our historical experience and assumptions that we believe to be reasonable at the time. However, because future events and their effects cannot be determined with certainty, the determination of estimates requires the exercise of judgment. Our critical accounting estimates are those which require assumptions to be made about matters that are highly uncertain.

Different estimates could have a material effect on our financial results. Judgments and uncertainties affecting the application of these policies and estimates may result in materially different amounts being reported under different conditions or circumstances. Historically, however, recorded estimates have not differed materially from actual results. Significant items subject to such judgments include: the carrying value of property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits. Refer to our Form 10-K for the fiscal year ended December 31, 2011 for a complete listing of our critical accounting policies and estimates. There have been no material changes to these critical accounting policies and estimates.

ELECTRIC SALES AND REVENUES

	DPL		DP&L *(a)*		DPLER *(b)*	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2012	2011	2012	2011	2012	2011
	Successor	Predecessor				
Electric Sales (millions of kWh)	$ **5,072**	$ 4,598	$ **4,775**	$ 4,310	$ **2,484**	$ 1,871
Billed electric customers (end of period)	**628,381**	515,758	**512,219**	512,439	**175,403**	25,309

	DPL		DP&L *(a)*		DPLER *(b)*	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011	2012	2011
	Successor	Predecessor				
Electric Sales (millions of kWh)	$ **12,323**	$ 12,712	$ **11,502**	$ 12,122	$ **6,100**	$ 5,011
Billed electric customers (end of period)	**628,381**	515,758	**512,219**	512,439	**175,403**	25,309

*(a) This chart contains electric sales from **DP&L's** generation and purchased power. **DP&L** sold 1,671 million kWh and 1,567 million kWh of power to DPLER during the three months ended September 30, 2012 and 2011, respectively, and 4,668 million kWh and 4,330 million kWh of power to DPLER during the nine months ended September 30, 2012 and 2011, respectively.*

*(b) This chart includes all sales of DPLER and MC Squared, both within and outside of the **DP&L** service territory.*

Item 3. Quantitative and Qualitative Disclosures about Market Risk

See the "MARKET RISK" section in Item 2 of this Part I, which is incorporated by reference into this item.

Item 4. Controls and Procedures
Our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) are responsible for establishing and maintaining our disclosure controls and procedures. These controls and procedures were designed to ensure that material information relating to us and our subsidiaries are communicated to the CEO and CFO. We evaluated these disclosure controls and procedures as of the end of the period covered by this report with the participation of our CEO and CFO. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective: (i) to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms; and (ii) to ensure that information required to be disclosed by us in the reports that we submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.
There was no change in our internal control over financial reporting during the quarter ended September 30, 2012 that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

PART II

Item 1. Legal Proceedings
In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We are also from time to time involved in other reviews, investigations and proceedings by governmental and regulatory agencies regarding our business, certain of which may result in adverse judgments, settlements, fines, penalties, injunctions or other relief. We believe the amounts provided in our Financial Statements, as prescribed by GAAP, for these matters are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters (including those matters noted below) and to comply with applicable laws and regulations will not exceed the amounts reflected in our Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided for in our Financial Statements, cannot be reasonably determined.
Our Form 10-K for the fiscal year ended December 31, 2011, and the Notes to the Condensed Consolidated Financial Statements included therein, contain descriptions of certain legal proceedings in which we are or were involved. The information in or incorporated by reference into this Item 1 to Part II of our Quarterly Report on Form 10-Q is limited to certain recent developments concerning our legal proceedings and new legal proceedings, since the filing of such Form 10-K, and should be read in conjunction with the Form 10-K.
The following information is incorporated by reference into this Item: (i) information about **DP&L's** March 30, 2012 MRO filing with the PUCO in Item 2 to Part I of this Quarterly Report on Form 10-Q; and (ii) information about the legal proceedings contained in Part I, Item 1 — Note 13 of Notes to **DPL's** Condensed Consolidated Financial Statements of this Quarterly Report on Form 10-Q.

Item 1A. Risk Factors
A listing of the risk factors that we consider to be the most significant to a decision to invest in our securities is provided in our Form 10-K for the fiscal year ended December 31, 2011. The information in this Item 1A to Part II of our Quarterly Report on Form 10-Q updates and restates one of the risk factors included in the Form 10-K. Otherwise, there have been no material changes with respect to the risk factors disclosed in our form 10-K. If

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any of the events described in our risk factors occur, it could have a material effect on our results of operations, financial condition and cash flows.
The risks and uncertainties described in our risk factors are not the only ones we face. In addition, new risks may emerge at any time, and we cannot predict those risks or estimate the extent to which they may affect our business or financial performance. Our risk factors should be read in conjunction with the other detailed information concerning **DPL** and **DP&L** set forth in the Notes to **DPL's** and **DP&L's** Financial Statements and the "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections included in our filings.
The costs we can recover and the return on capital we are permitted to earn for certain aspects of our business are regulated and governed by the laws of Ohio and the rules, policies and procedures of the PUCO.
On May 1, 2008, SB 221, an Ohio electric energy bill, was signed by the Governor of Ohio and became effective July 31, 2008. This law, among other things, requires all Ohio distribution utilities at certain times to file an SSO either in the form of an ESP or MRO, and established a significantly excessive earnings test (SEET) for Ohio public utilities that compares the utility's earnings to the earnings of other companies with similar business and financial risks. The PUCO approved **DP&L's** initial ESP on June 24, 2009. **DP&L's** ESP provided, among other things, that

DP&L's existing rate plan structure will continue through the end of 2012; that **DP&L** may seek recovery for adjustments to its existing rate plan structure for costs associated with storm damage, regulatory and tax changes, new climate change or carbon regulations, fuel and purchased power and certain other costs; and that SB 221's significantly excessive earnings test will apply in 2013 based upon **DP&L's** 2012 earnings. On March 30, 2012, **DP&L** filed an MRO to establish a new rate plan and recovery structure that would have phased in market-based rates over the time period January 2013 through May 2018. **DP&L** withdrew its MRO on September 7, 2012 and filed an ESP on October 5, 2012. As filed, **DP&L's** proposed ESP provides an initial rate increase for certain customers and decreases for others. The outcome of this filing will impact **DP&L's** revenues and could adversely affect our results of operations. **DP&L** faces regulatory uncertainty from this ESP filing. The PUCO could accept, reject or seek to modify **DP&L's** proposed ESP. **DP&L's** proposed ESP and current ESP and certain filings made by us in connection with these plans are further discussed in our periodic reports. Through the pending ESP filing, the PUCO may modify the non-bypassable charge, or may establish other rate designs and provisions to reflect new terms and conditions of standard offer service. The SEET review could result in no adjustment to SSO rates or a refund to customers. The effect may or may not be significant.

While traditional rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the PUCO will agree that all of our costs have been prudently incurred or are recoverable or that the regulatory process in which rates are determined will always result in rates that will produce a full or timely recovery of our costs and permitted rates of return. Certain of our cost recovery riders are also bypassable by some of our customers who switched to a CRES provider. Accordingly, the revenue **DP&L** receives may or may not match its expenses at any given time. Therefore, **DP&L** could be subject to prevailing market prices for electricity and would not necessarily be able to charge rates that produce timely or full recovery of its expenses. Changes in, or reinterpretations of, the laws, rules, policies and procedures that set electric rates, permitted rates of return and standard service offer; changes in **DP&L's** rate structure and its ability to recover amounts for environmental compliance, standard service offer terms and conditions, reliability initiatives, fuel and purchased power (which account for a substantial portion of our operating costs), customer switching, capital expenditures and investments and other costs on a full or timely basis through rates; and changes to the frequency and timing of rate increases could have a material adverse effect on our results of operations, financial condition and cash flows.

Impairment of goodwill or long-lived assets would negatively affect our consolidated results of operations and net worth.

Goodwill represents the future economic benefits arising from assets acquired in a business combination (acquisition) that are not individually identified and separately recognized. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if impairment indicators are present. In evaluating the potential impairment of goodwill, we make estimates and assumptions about revenue, operating cash flows, capital expenditures, growth rates and discount rates based on our budgets and long term forecasts, macroeconomic projections, and current market expectations of returns on similar assets. There are inherent uncertainties related to these factors and management's judgment in applying these factors. Generally, the fair value of a reporting unit is determined using a discounted cash flow valuation model. We could be required to

evaluate the potential impairment of goodwill outside of the required annual assessment process if we experience situations, including but not limited to: deterioration in general economic conditions, operating or regulatory environment; increased competitive environment; increase in fuel costs particularly when we are unable to pass along such costs to customers; negative or declining cash flows; loss of a key contract or customer particularly when we are unable to replace it on equally favorable terms; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. A goodwill impairment could lead to a rating downgrade and adversely impact the trading price of **DPL's** bonds.

Long-lived assets are initially recorded at fair value when acquired in a business combination and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long-lived assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above.

Item 2. Unregistered Sale of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities
None
Item 4. Mine Safety Disclosures
Not applicable.
Item 5. Other Information
None

Item 6. Exhibits

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location
X		31(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(a)
X		31(b)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(b)
	X	31(c)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(c)
	X	31(d)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(d)
X		32(a)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(a)
X		32(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(b)
	X	32(c)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(c)
	X	32(d)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(d)

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location
X	X	101.INS	XBRL Instance	Furnished herewith as Exhibit 101.INS
X	X	101.SCH	XBRL Taxonomy Extension Schema	Furnished herewith as Exhibit 101.SCH
X	X	101.CAL	XBRL Taxonomy Extension Calculation Linkbase	Furnished herewith as Exhibit 101.CAL
X	X	101.DEF	XBRL Taxonomy Extension Definition Linkbase	Furnished herewith as Exhibit 101.DEF
X	X	101.LAB	XBRL Taxonomy Extension Label Linkbase	Furnished herewith as Exhibit 101.LAB
X	X	101.PRE	XBRL Taxonomy Extension Presentation Linkbase	Furnished herewith as Exhibit 101.PRE

Exhibits referencing File No. 1-9052 have been filed by **DPL Inc.** and those referencing File No. 1-2385 have been filed by The Dayton Power and Light Company.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, we have not filed as an exhibit to this form 10-Q certain instruments with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of us and our subsidiaries on a consolidated basis, but we hereby agree to furnish to the SEC on request any such instruments.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, DPL Inc. and The Dayton Power and Light Company have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized.

		DPL Inc.
		The Dayton Power and Light Company
		(Registrants)
Date:	November 6, 2012	/s/ Philip Herrington
		Philip Herrington President and Chief Executive Officer (principal executive officer)
	November 6, 2012	/s/ Craig Jackson
		Craig Jackson Senior Vice President and Chief Financial Officer (principal financial officer)
	November 6, 2012	/s/ Gregory S. Campbell
		Gregory S. Campbell Vice President and Controller (principal accounting officer)