Large Filing Separator Sheet

Case Number: 12-426-EL-SSO
12-427-EL-ATA
12-428-EL-AAM
12-429-EL-WVR
12-672-EL-RDR

Date Filed: 4/4/2013

Section: 2 OF 2

Number of Pages: 216

Description of Document: IEU Exhibit No. 21 cont'd

During the year ended December 31, 2011, General taxes increased $3.5 million to $75.9 million compared to 2010. This increase was primarily the result of higher property tax accruals in 2011 compared to 2010.

DP&L – Fixed-asset Impairment

During the year ended December 31, 2012, **DP&L** recorded an impairment of certain generation facilities of $80.8 million. See Note 15 of Notes to **DP&L's** Financial Statements.

DP&L – Interest Expense

Interest expense recorded during 2012 did not fluctuate significantly from that recorded in 2011.

Interest expense recorded during 2011 did not fluctuate significantly from that recorded in 2010.

DP&L – Income Tax Expense

During the year ended December 31, 2012, Income tax expense decreased $49.1 million compared to 2011 primarily due to decreases in pre-tax income, lower non-deductible compensation expenses related to the Merger and a write-off in 2011 of a deferred tax asset on the termination of the ESOP. These were partially offset by a reduction in Internal Revenue Code Section 199 tax benefits and an adjustment of property-related deferred taxes.

During the year ended December 31, 2011, Income tax expense decreased $31.0 million compared to 2010 primarily due to decreases in pre-tax income offset by non-deductible compensation expenses related to the Merger, a reduction in Internal Revenue Code Section 199 tax benefits and a write-off of a deferred tax asset on the termination of the ESOP.

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL REQUIREMENTS

DPL's financial condition, liquidity and capital requirements include the consolidated 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	Successor	Combined	Successor	Predecessor	
$ in millions	**Year ended December 31, 2012**	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31, 2010
Net cash from operating activities	**291.5**	333.0	(1.4)	334.4	473.1
Net cash from investing	**(199.2)**	(151.1)	(30.4)	(120.7)	(229.5

activities					
Net cash from financing activities	**(73.7)**	(151.6)	88.9	(240.5)	(194.5
Net change	**18.6**	30.3	57.1	(26.8)	49.1
Assumption of cash at acquisition	-	19.2	19.2	-	-
Cash and cash equivalents at beginning of period	**173.5**	124.0	97.2	124.0	74.9
Cash and cash equivalents at end of period	**192.1**	173.5	173.5	97.2	124.0

DP&L	Years ended December 31,		
$ in millions	**2012**	2011	2010
Net cash from operating activities	**339.8**	364.2	455.3
Net cash from investing activities	**(197.5)**	(185.0)	(157.5
Net cash from financing activities	**(146.0)**	(201.0)	(300.9
Net change	**(3.7)**	(21.8)	(3.1
Cash and cash equivalents at beginning of period	**32.2**	54.0	57.1
Cash and cash equivalents at end of period	**28.5**	32.2	54.0

The significant items that have impacted the cash flows for **DPL** and **DP&L** are discussed in greater detail below:

DPL – Net Cash provided by Operating Activities

DPL's Net cash provided by operating activities for the years ended December 31, 2012, 2011 and 2010 are summarized as follows:

	Successor	**Combined**	**Successor**	**Predecessor**	
$ in millions	**Year ended December 31, 2012**	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31, 2010
Net income	**(1,729.8)**	144.3	(6.2)	150.5	290.3
Depreciation and amortization	**201.5**	152.6	23.2	129.4	139.4
Deferred income taxes	**(4.2)**	65.6	0.1	65.5	59.9
Impairment of Goodwill	**1,817.2**	-	-	-	-
Recognition of deferred SECA	**(17.8)**	-	-	-	-
Charge for early redemption of	-	15.3	-	15.3	-

debt					
Contribution to pension plan	-	(40.0)	-	(40.0)	(40.0
Deferred regulatory assets, net	**(1.1)**	(14.3)	0.1	(14.4)	21.8
Cash settlement of interest rate hedges, net of tax	-	(31.3)	-	(31.3)	-
Other	**25.7**	40.8	(18.6)	59.4	1.7
Net cash from operating activities	**291.5**	333.0	(1.4)	334.4	473.1

During the year ended December 31, 2012, Net cash provided by operating activities was primarily a result of Net income adjusted for noncash depreciation and amortization, as well as a noncash charge for the impairment of goodwill.

During the year ended December 31, 2011, Net cash provided by operating activities was primarily a result of Net income adjusted for noncash depreciation and amortization, combined with the following significant transactions:

- The $65.6 million increase to Deferred income taxes primarily results from changes related tc pension contributions, depreciation expense and repair expense.
- A $15.3 million charge for the early redemption of DPL Capital Trust II securities.
- **DP&L** made discretionary contributions of $40.0 million to the defined benefit pension plan in 2011.
- **DPL** made a cash payment of $48.1 million ($31.3 million net of tax) related to interest rate hedge contracts that settled during the period.
- 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, interest and taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances.

During the year ended December 31, 2010, Net cash provided by operating activities was primarily a result of Net income adjusted for noncash depreciation and amortization, combined with the following significant transactions:

- The $59.9 million increase to Deferred income taxes primarily results from changes related tc pension contributions, depreciation expense and repair expense.
- **DP&L** made discretionary contributions of $40.0 million to the defined benefit pension plan in 2010.
- 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, interest and taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances.

DP&L – Net Cash provided by Operating Activities

DP&L's Net cash provided by operating activities for the years ended December 31, 2012, 2011 and 2010 are summarized as follows:

$ in millions	Years ended December 31, 2012	2011	2010
Net income	**91.2**	193.2	277.7
Depreciation and amortization	**141.3**	134.9	130.7
Deferred income taxes	**3.6**	50.7	54.3
Fixed asset impairment	**80.8**	-	-
Recognition of deferred SECA	**(17.8)**	-	-
Contribution to pension plan	-	(40.0)	(40.0
Deferred regulatory assets, net	**(1.5)**	(12.6)	21.8
Other	**42.2**	38.0	10.8
Net cash from operating activities	**339.8**	364.2	455.3

During the year ended December 31, 2012 the significant components of **DP&L's** Net cash provided by operating activities was primarily a result of Net income adjusted for noncash depreciation and amortization, as well as a noncash charge related to the impairment of certain generation facilities. During the years ended December 31, 2011 and 2010, 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 used for Investing Activities

DPL's Net cash used for investing activities for the years ended December 31, 2012, 2011 and 2010 are summarized as follows:

$ in millions	**Successor** Year ended December 31, 2012	**Combined** Year ended December 31, 2011	**Successor** November 28, 2011 through December 31, 2011	**Predecessor** January 1, 2011 through November 27, 2011	**Predecessor** Year ended December 31, 2010
Environmental and renewable energy capital expenditures	**(8.2)**	(11.8)	-	(11.8)	(11.9
Other plant-related asset acquisitions	**(189.9)**	(192.9)	(30.5)	(162.4)	(140.8
Purchase of MC Squared	-	(8.3)	-	(8.3)	-
Proceeds from sale of short-term investments	-	69.2	-	69.2	(69.3
Other	**(1.1)**	(7.3)	0.1	(7.4)	(7.5
Net cash from investing activities	**(199.2)**	(151.1)	(30.4)	(120.7)	(229.5

During the year ended December 31, 2012, **DP&L's** environmental expenditures were primarily related to pollution control devices at our electric generation stations.

During the year ended December 31, 2011, **DP&L's** environmental expenditures were primarily related to pollution control devices at our generation stations. Additionally, **DPL**, on behalf of DPLER, made a cash payment of approximately $8.3 million to acquire MC Squared. Furthermore, **DPL** redeemed $70.9 million of short-term investments mostly comprised of VRDN securities and purchased an additional $1.7 million of short-term investments during the same period. The VRDN securities have variable coupon rates that are typically re-set weekly relative to various short-term rate indices. **DPL** can tender these securities for sale upon notice to the broker and receive payment for the tendered securities within seven days.

During the year ended December 31, 2010, **DP&L** continued to see reductions in its environmental capital expenditures due to the completion of FGD and SCR projects including the FGD and SCR equipment completed and placed into service at Conesville during the fourth quarter of 2010. Approximately $4.2 million of the environmental capital expenditures incurred during 2010 relate to the construction of a solar energy facility at Yankee station. **DP&L** also continued to make upgrades and other investments in other generation, transmission

and distribution equipment. Additionally, **DPL** purchased $54.2 million of VRDN securities, net of redemptions from various institutional securities brokers as well as $15.1 million of investment-grade fixed income corporate bonds. The VRDN securities are backed by irrevocable letters of credit. These securities have variable coupon rates that are typically re-set 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 used for Investing Activities

DP&L's Net cash used for investing activities for the years ended December 31, 2012, 2011 and 2010 are summarized as follows:

	Years ended December 31,		
$ in millions	**2012**	2011	2010
Environmental and renewable energy capital expenditures	**(8.2)**	(11.8)	(11.9
Other plant-related asset acquisitions	**(187.3)**	(192.7)	(138.1
Proceeds from liquidation of **DPL** stock, held in trust	**-**	26.9	-
Other	**(2.0)**	(7.4)	(7.5
Net cash from investing activities	**(197.5)**	(185.0)	(157.5

During the year ended December 31, 2012, **DP&L's** environmental expenditures were primarily related to pollution control devices at our generation stations.

During the year ended December 31, 2011, **DP&L's** environmental expenditures were primarily related to pollution control devices at our generation stations. Additionally, **DP&L** received proceeds of $26.9 million related to the liquidation of **DPL** stock held in the Master Trust.

During the year ended December 31, 2010, **DP&L** continued to see reductions in its environmental capital expenditures due to the completion of

FGD and SCR projects including the FGD and SCR equipment completed and placed into service at Conesville during the fourth quarter of 2010. Approximately $4.2 million of the environmental capital expenditures incurred during 2010 relate to the construction of a solar energy facility at Yankee station. **DP&L** also continued to make upgrades and other investments in other generation, transmission and distribution equipment.

DPL – Net Cash used for Financing Activities

DPL's Net cash used for financing activities for the years ended December 31, 2012, 2011 and 2010 are summarized as follows:

$ in millions	**Successor** Year ended December 31, 2012	**Combined** Year ended December 31, 2011	**Successor** November 28, 2011 through December 31, 2011	**Predecessor** January 1, 2011 through November 27, 2011	**Predecessor** Year ended December 31, 2010
Dividends paid on common stock	**(64.1)**	(176.0)	(63.0)	(113.0)	(139.7
Retirement of long-term debt	**(0.1)**	(297.5)	-	(297.5)	-
Early redemption of long-term debt, including premium	-	(134.2)	-	(134.2)	-
Payment of MC Squared debt	-	(13.5)	-	(13.5)	-
Repurchase of **DPL** common stock	-	-	-	-	(56.4
Payment to former warrant holders	**(9.0)**	-	-	-	-
Issuance of long-term debt	-	425.0	125.0	300.0	-
Proceeds from liquidation of **DPL** stock, held in trust	-	26.9	26.9	-	-
Proceeds from exercise of warrants	-	14.7	-	14.7	-
Other	**(0.5)**	3.0	-	3.0	1.6
Net cash from financing activities	**(73.7)**	(151.6)	88.9	(240.5)	(194.5

During the year ended December 31, 2012, **DPL's** Net cash from financing activities primarily relate to common stock dividends and payments to a former warrant holder.

During the year ended December 31, 2011, **DPL** paid common stock dividends of $176.0 million and retired long-term debt of $297.5 million. Additionally, **DPL** paid $134.2 million for its purchase of a portion 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. **DPL** received $425.0 million from the issuance of additional debt. **DPL** received $26.9 million upon the liquidation of **DPL** stock held in the **DP&L** Master Trust and $14.7 million from the exercise of 700,000 warrants.

During the year ended December 31, 2010, **DPL** paid common stock dividends of $139.7 million. In addition, under the stock repurchase programs approved by the Board of Directors in October 2009 and October 2010 (see Note 14 of Notes to **DPL's** Consolidated Financial Statements), **DPL** repurchased approximately 2.18 million **DPL** common shares for $56.4 million.

DP&L – Net Cash used for Financing Activities

DP&L's Net cash used for financing activities for the years ended December 31, 2012, 2011 and 2010 are summarized as follows:

	Years ended December 31,		
$ in millions	**2012**	2011	2010
Dividends paid on common stock	**(145.0)**	(220.0)	(300.0
Cash contribution from parent	-	20.0	-
Cash withdrawn from restricted funds	-	-	-
Other	**(1.0)**	(1.0)	(0.9
Net cash from financing activities	**(146.0)**	(201.0)	(300.9

During the year ended December 31, 2012, **DP&L's** Net cash used for financing activities primarily relates to $145 million in dividends.

During the year ended December 31, 2011, **DP&L's** Net cash used for financing activities primarily relates to $220 million in dividends offset by $20 million of additional capital contributed by **DPL**.

During the year ended December 31, 2010, **DP&L's** Net cash used for financing activities primarily relates to $300 million in dividends.

Liquidity

We expect our existing sources of liquidity to remain sufficient to meet our anticipated obligations. Our business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities, taxes, interest and dividend payments. For 2013 and 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 credit facilities will continue to be available to manage working capital requirements during those periods.

At the filing date of this annual report on Form 10-K, **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 borrowing 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 borrowing under the second facility by $50.0 million.

At the filing date of this annual report on Form 10-K, **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. In addition, **DPL** entered into a $425.0 million unsecured term loan agreement with a syndicated bank group in August 2011. This agreement is for a three year term expiring on August 24, 2014. The entire $425.0 million has been drawn under this facility.

$ in millions	Type	Maturity	Commitment	Amounts available as of December 31, 2012
DP&L	Revolving	August 2015	200.0	200.0
DP&L	Revolving	April 2013	200.0	200.0
DPL	Revolving	August 2014	75.0	75.0
			475.0	475.0

Each **DP&L** revolving credit facility has a $50 million letter of credit sublimit. The entire **DPL** revolving credit facility amount is available for letter of credit issuances. As of December 31, 2012 and through the date of filing this annual report on Form 10-K, 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 $192.1 million and $28.5 million, respectively, at December 31, 2012. At that date, neither **DPL** nor **DP&L** had short-term investments.

Capital Requirements

CONSTRUCTION ADDITIONS

	Actual			Projected		
$ in millions	2010	2011	2012	2013	2014	2015
DPL	151	201	180	155	150	165
DP&L	148	199	177	140	145	160

Planned construction additions for 2013 relate primarily to new investments in and upgrades to **DP&L's** electric generating station 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, through its subsidiary **DP&L**, is projecting to spend an estimated $470.0 million in capital projects for the period 2013 through 2015. 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 recently 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 five 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 that was not to exceed 0.70 to 1.00, was changed, effective September 30, 2012, to a Total Debt to EBITDA (**DPL's** consolidated earnings before interest, taxes, depreciation and amortization) 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 7.00 to 1.00 for the for the period September 30, 2012 through December 31, 2012; it then steps up to not exceed 7.75 to 1.00 for the period January 1, 2013 through March 31, 2013; it then steps up to not exceed 8.00 to 1.00 for the period April 1, 2013 through June 30, 2013; and finally it steps up to not exceed 8.25 to 1.00 as of July 1, 2013 and thereafter. As of December 31, 2012, the first financial covenant was met with a ratio of 5.57 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 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 December 31, 2012, the second covenant was met with a ratio of 3.77 to 1.00.

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 December 31, 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 guaranty obligations, divided by the total of **DP&L's** shareholders' equity and total debt including guaranty 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+	Rating Watch Negative	November 2012
Moody's Investors Service, Inc.	Ba1	A3	Under Review for Downgrade	November 2012
Standard & Poor's Financial Services LLC	BB	BBB-	Stable	November 2012

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 (a)	**DP&L** (b)	Outlook	Effective
Fitch Ratings	BB	BBB-	Rating Watch Negative	November 2012
Moody's Investors Service, Inc.	Ba1	Baa2	Under Review for	November 2012

Standard & Poor's Financial Services LLC	BB	BB	Downgrade Stable	November 2012

On November 7, 2012, Fitch Ratings issued a new **DPL** issuer credit rating (Credit Rating) and a new rating on **DPL's** senior unsecured debt (Debt Rating) of BB with an outlook of "Rating Watch Negative". **DP&L** did not receive a new rating, but the outlook on its issuer credit rating and **DP&L's** senior secured debt changed to "Rating Watch Negative". On November 8, 2012, Standard and Poor's Ratings Services issued a new **DPL** issuer credit rating (Credit Rating) of BB and a new rating on **DPL's** senior unsecured debt (Debt Rating) of BB- with an outlook of "Stable". On November 9th 2012, Moody's Investors Services, Inc. placed all the ratings of **DPL** and **DP&L** under review for possible downgrade. Standard and Poor's also downgraded **DP&L's** issuer rating (Credit Rating) to BB and **DP&L's** senior secured debt (Debt Rating) rating to BBB- with an outlook of "Stable". The change in ratings from our rating agencies could have an impact on the market price of our debt and **DP&L's** preferred stock.

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. Non-investment grade companies, such as **DPL**, may experience higher costs to issue new securities. **DP&L** is still considered investment grade by two of the three rating agencies above.

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 year ended December 31, 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 December 31, 2012, **DPL** had $21.5 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

Consolidated Balance Sheets was $0.0 million at December 31, 2012 and $0.1 million at December 31, 2011.

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. **DP&L** could be responsible for the repayment of 4.9%, or $78.2 million, of a $1,596.5 million debt obligation comprised of both fixed and variable rate securities with maturities between 2013 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2012, we have no knowledge of such a default.

Commercial Commitments and Contractual Obligations

We enter into various contractual obligations and other commercial commitments that may affect the liquidity of our operations. At December 31, 2012, these include:

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DPL:					
Long-term debt	2,598.7	570.4	425.3	450.2	1,152.8
Interest payments	1,031.4	133.5	216.3	174.1	507.5
Pension and postretirement payments	256.2	24.6	50.3	51.1	130.2
Operating leases	1.0	0.4	0.6	-	-
Coal contracts [(a)]	586.4	227.6	150.6	138.8	69.4
Limestone contracts [(a)]	26.8	5.4	10.7	10.7	-
Purchase orders and other contractual obligations	55.9	34.6	10.9	10.4	-
Reserve for uncertain tax positions	18.3	18.3	-	-	-
Total contractual obligations	4,574.7	1,014.8	864.7	835.3	1,859.9

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DP&L:					
Long-term debt	903.2	570.4	0.3	0.2	332.3
Interest payments	361.9	34.0	31.6	31.6	264.7
Pension and postretirement payments	256.2	24.6	50.3	51.1	130.2
Operating leases	1.0	0.4	0.6	-	-
Coal contracts [(a)]	586.4	227.6	150.6	138.8	69.4
Limestone contracts [(a)]	26.8	5.4	10.7	10.7	-
Purchase orders and other contractual obligations	55.9	34.6	10.9	10.4	-
Reserve for uncertain tax positions	18.3	18.3	-	-	-
Total contractual obligations	2,209.7	915.3	255.0	242.8	796.6

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

Long-term debt:

DPL's Long-term debt as of December 31, 2012 consists 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 (WPAFB) note. These long-term debt amounts include current maturities but exclude unamortized debt discounts, premiums and fair value adjustments.

DP&L's Long-term debt as of December 31, 2012 consists of its first mortgage bonds, tax-exempt pollution control bonds, capital leases and the WPAFB note. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 7 of the Notes to **DPL's** Consolidated Financial Statements and Note 6 of the Notes to **DP&L's** 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, 2012.

Pension and postretirement payments:

As of December 31, 2012, **DPL**, through its principal subsidiary **DP&L**, had estimated future benefit payments as outlined in Note 9 of Notes to **DPL's** Consolidated Financial Statements and Note 8 of Notes to **DP&L's** Financial Statements. These estimated future benefit payments are projected through 2022.

Capital leases:

As of December 31, 2012, **DPL**, through its principal subsidiary **DP&L**, had two immaterial capital leases that expire in 2013 and 2014.

Operating leases:

As of December 31, 2012, **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 stations 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, 2012, **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:

As of December 31, 2012, **DPL** and **DP&L** had $18.3 million in uncertain tax positions which are expected to be resolved within the next year.

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 related 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 wholesale sales requirements for 2013 under contract, sales requirements may change, particularly for retail load. The majority of the contracted coal is purchased at fixed prices. Some contracts provide for periodic adjustments and some are priced based on market indices. 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 electric generation station 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.*

In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), signed into law in July 2010, contains significant requirements relating to derivatives, including, among others, a requirement that certain transactions be cleared on exchanges that would necessitate the posting of cash collateral for these transactions. The Dodd-Frank Act provides a potential exception from these clearing and cash collateral requirements for commercial end-users. The Dodd-Frank Act requires the Commodity Futures Trading Commission to establish rules to implement the Dodd-Frank Act's requirements and exceptions. Requirements to post collateral could reduce the cost effectiveness of entering into derivative transactions to reduce commodity price and interest rate volatility or could increase the demands on our liquidity or require us to increase our levels of debt to enter into such derivative transactions. Even if we were to qualify for an exception from these requirements, our counterparties that do not qualify for the exception may pass along any increased costs incurred by them through higher prices and reductions in unsecured credit limits or be unable to enter into certain transactions with us.

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 counterparty 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 at December 31, 2012 would not have a significant effect on Net income.

The following table provides information regarding the volume and average market price of our power forward derivative contracts at December 31, 2012 and the effect to Net income if the market price were to increase or decrease by 10%:

Power Forwards	Contract Volume (in millions of tons)	Weighted Average Market Price per ton	Increase / decrease in Net income (in millions)
		$ 3	$
2013- Net Purchase/(Sale) Position	(0.9)	4.14	(2.2
2014- Net Purchase/(Sale) Position	(0.6)	$ 3	$

5.45 (1.6

Wholesale revenues

Approximately 11% of **DPL's** and 36% of **DP&L's** electric revenues for the year ended December 31, 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 35% of **DP&L's** electric revenues for the year ended December 31, 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 18% of **DPL's** and 30% of **DP&L's** electric revenues for the year ended December 31, 2010 were from sales of excess energy and capacity in the wholesale market. 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 December 31, 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 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	6.0	5.1

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:

($/MW-day)	PJM Delivery Year				
	2011/12	2012/13	2013/14	2014/15	2015/1[illegible]
Capacity clearing price	110	16	28	126	13[illegible]

Our computed average capacity prices by calendar year are reflected in the table below:

($/MW-day)	Calendar Year 2011	2012	2013	2014	2015
Computed average capacity price	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 December 31, 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 December 31, 2012. As of December 31, 2012, approximately 34% 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 $10/MW-day change in capacity auction pricing	5.9	4.5

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 years ended December 31, 2012, 2011 and 2010 were 39%, 37% and 43%, respectively. We have a significant portion of projected 2013 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 2013; 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 2013 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 electric generation station 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 34% of **DP&L's** total fuel costs. The table below provides the effect on annual net income as of December 31, 2012, of a hypothetical increase or decrease of 10% in the prices of fuel and purchased power, adjusted for the approximate 34% recovery:

$ in millions	DPL	DP&L
Effect of 10% change in fuel and purchased power	23.2	21.6

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 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 7 of Notes to **DPL's** Consolidated 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 December 31, 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.

The carrying value of **DPL's** debt was $2,609.9 million at December 31, 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 WPAFB 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 December 31, 2012 was $2,707.1 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:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

DPL	Years ending December 31,						Principal amount at December 31, 2012 (a)	Fair value at December 31, 2012
$ in millions	2013	2014	2015	2016	2017	Thereafter		
Long-term debt								
Variable-rate debt	100.0	425.0	-	-	-	-	525.0	525.0
Average interest rate	0.2 %	2.5 %	0.0 %	0.0 %	0.0 %	0.0 %		
Fixed-rate debt	470.4	0.2	0.1	450.1	0.1	1,152.8	2,073.7	2,182.1
Average interest rate	5.1 %	5.2 %	4.2 %	6.5 %	4.2 %	6.6 %		
Total							2,598.7	2,707.1

The carrying value of **DP&L's** debt was $903.1 million at December 31, 2012, consisting of its first mortgage bonds, tax-exempt pollution control bonds, capital leases and the WPAFB note. The fair value of this debt at December 31, 2012 was $926.9 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.

Principal Payments and Interest Rate Detail by Contractual Maturity Date

DP&L	Years ending December 31,						Principal amount at December 31, 2012 (a)	Fair value at December 31, 2012
$ in millions	2013	2014	2015	2016	2017	Thereafter		
Long-term debt								

Variable-rate debt	100.0	-	-	-	-	-	100.0	100.0
Average interest rate	0.2 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %		
Fixed-rate debt	470.4	0.2	0.1	0.1	0.1	332.3	803.2	826.9
Average interest rate	5.1 %	5.2 %	4.2 %	4.2 %	4.2 %	4.8 %		
Total							903.2	926.9

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 December 31, 2012 and 2011 for which an immediate adverse market movement causes a potential material effect on our financial condition, 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 December 31, 2012 and 2011, we did not hold any market risk sensitive instruments which were entered into for trading purposes.

Carrying value and fair value of debt with one percent interest rate risk

DPL

$ in millions	Carrying value at December 31, 2012 (a)	Fair value at December 31, 2012	One Percent Interest Rate Risk	Carrying value at December 31, 2011 (a)	Fair value at December 31, 2011	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	525.0	525.0	5.3	525.0	525.0	5.3
Fixed-rate debt	2,084.9	2,182.1	21.8	2,104.3	2,185.6	21.9
Total	2,609.9	2,707.1	27.1	2,629.3	2,710.6	27.2

(a) Carrying value includes unamortized debt discounts and premiums.

DP&L

$ in millions	Carrying value at December	Fair value at December	One Percent Interest	Carrying value at December	Fair value at December	One Percent Interest

	31, 2012 (a)	31, 2012	Rate Risk	31, 2011 (a)	31, 2011	Rate Risk
Long-term debt						
Variable-rate debt	100.0	100.0	1.0	100.0	100.0	1.C
Fixed-rate debt	803.1	826.9	8.3	803.4	834.5	8.3
Total	903.1	926.9	9.3	903.4	934.5	9.3

(a) Carrying value includes unamortized debt discounts and premiums.

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** $2,182.1 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 the fair value of **DPL's** $525.0 million variable-rate long-term debt outstanding as of December 31, 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** $826.9 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 the fair value of **DP&L's** $100.0 million variable-rate long-term debt outstanding as of December 31, 2012.

Equity Price Risk

As of December 31, 2012, approximately 27% of the defined benefit pension plan assets were comprised of investments in equity securities and 73% related to investments in fixed income securities, cash and cash equivalents, and alternative investments. The equity securities are carried at their market value of approximately $101.1 million at December 31, 2012. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $10.1 million reduction in fair value as of December 31, 2012 and approximately a $0.7 million increase to the 2013 pension expense.

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 counterparties on an ongoing basis. We may require various forms of credit assurance from counterparties in order to mitigate credit risk.

Critical Accounting Estimates

DPL's Consolidated Financial Statements and **DP&L's** 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.

Impairments and Assets Held for Sale

In accordance with the provisions of GAAP relating to the accounting for 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 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. Please see Note 19 of Notes to **DPL's** Consolidated Financial Statements discussing the impairment of goodwill at **DPL** in 2012.

In accordance with the provisions of GAAP relating to the accounting for impairments, long-lived assets to be held and used are reviewed for impairment whenever events or circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets to be held and used are recognized based on the fair value of the asset. We determine the fair value of these assets based upon estimates of future cash flows, market value of similar assets, if available, or independent appraisals, if required. In analyzing the fair value and recoverability using future cash flows, we make projections based on a number of assumptions and estimates of growth rates, future economic conditions, assignment of discount rates and estimates of terminal values. An impairment loss is recognized if the carrying amount of the long-lived asset is not recoverable from its undiscounted cash flows. The measurement of impairment loss is the difference between the carrying amount and fair value of the asset. Please see Note 15 of Notes to **DP&L's** Financial Statements discussing the impairment of long-lived assets at **DP&L** in 2012.

Revenue Recognition (including Unbilled Revenue)

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. The determination of the energy sales to customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. We recognize revenues 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, projected line losses, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Given our estimation method and the fact that customers are billed monthly, we believe it is unlikely that materially different results will occur in future periods when these amounts are subsequently billed.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since taxing authorities may interpret them differently. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to Net income and cash flows and adjustments to tax-related assets and liabilities could be material. We have adopted the provisions of GAAP relating to the accounting for uncertainty in income taxes. Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, these GAAP provisions establish standards for recognition and measurement in financial statements of positions taken, or expected to be taken, by an entity on its income tax returns. Positions taken by an entity on its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

Deferred income tax assets and liabilities represent future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. We evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets.

Regulatory Assets and Liabilities

Application of the provisions of GAAP relating to regulatory accounting requires us to reflect the effect of rate regulation in **DPL's** Consolidated Financial Statements and **DP&L's** Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, we defer these costs as Regulatory assets that otherwise would be expensed by nonregulated companies. Likewise, we recognize Regulatory liabilities when it is probable that regulators will require customer refunds through future rates and when revenue is collected from customers for expenses that are not yet incurred. Regulatory assets are amortized into expense and Regulatory liabilities are amortized into income over the recovery period authorized by the regulator.

We evaluate our Regulatory assets to determine whether or not they are probable of recovery through future rates and make various assumptions in our analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions or historical experience, as well as discussions with applicable regulatory authorities. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period the assessment is made. We currently believe the recovery of our Regulatory assets is probable. See Note 4 of Notes to **DPL's** Consolidated Financial Statements and Note 4 of Notes to **DP&L's** Financial Statements.

AROs

In accordance with the provisions of GAAP relating to the accounting for AROs, legal obligations associated with the retirement of long-lived assets are required 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 allocated to expense over the useful life of the asset. These GAAP provisions also require that components of previously recorded depreciation related to the cost of removal of assets upon future retirement, whether legal AROs or not, must be removed from a company's accumulated depreciation reserve and be reclassified as a regulatory liability. We make assumptions, estimates and judgments that affect the reported

amounts of assets, liabilities and expenses as they relate to AROs. These assumptions and estimates are based on historical experience and assumptions that we believe to be reasonable at the time.

Insurance and Claims Costs

In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of **DPL**, provides insurance coverage solely 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 **DPL's** Consolidated Balance Sheets include estimated liabilities for insurance and claims costs of approximately $11.5 million and $14.2 million at December 31, 2012 and 2011, 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 estimated liabilities for medical, life and disability claims costs below certain coverage thresholds of third-party providers. **DPL** and **DP&L** record these additional insurance and claims costs of approximately $17.7 million and $18.9 million for 2012 and 2011, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for MVIC at **DPL** and the estimated liabilities for workers' compensation, medical, life and disability claims at **DP&L** are actuarially determined based on a reasonable estimation of insured events occurring. There is uncertainty associated with the 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.

Pension and Postretirement Benefits

We account for and disclose pension and postretirement benefits in accordance with the provisions of GAAP relating to the accounting for pension and other postretirement plans. These GAAP provisions require the use of assumptions, such as the discount rate for liabilities and long-term rate of return on assets, in determining the obligations, annual cost, and funding requirements of the plans.

For 2013, we are maintaining our long-term rate of return assumption of 7.00% for pension plan assets and 6.00% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our current portfolio mixes. Also, for 2013, we have decreased our assumed discount rate to 4.04% from 4.88% for pension and to 3.75% from 4.62% for postretirement benefits expense to reflect current duration-based yield curve discount rates. A one percent change in the rate of return assumption for pension would result in an increase or decrease to the 2013 pension expense of approximately $3.5 million. A one percent increase in the discount rate for pension would result in a decrease of approximately $1.5 million to 2013 pension expense. A one percent decrease in the discount rate for pension would result in an increase of approximately $2.8 million to 2013 pension expense.

In future periods, differences in the actual return on pension and other post-employment benefit plan assets and assumed return, or changes in the discount rate, will affect the timing of contributions to the plans, if any. We provide postretirement health care benefits to employees who retired prior to 1987. A one percentage point change in the assumed health care cost trend rate would affect postretirement benefit costs by less than $1.0 million.

Contingent and Other Obligations

During the conduct of our business, we are subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject us to environmental, litigation, insurance and other risks. We periodically evaluate our exposure to such risks and record estimated liabilities for those matters where a loss is considered probable and reasonably estimable in accordance with GAAP. In recording such estimated liabilities, we may make assumptions, estimates and judgments that affect the reported amounts of assets, liabilities and expenses as they relate to contingent and other obligations. These assumptions and estimates are based on historical experience and assumptions and may be subject to change. We, however, believe such estimates and assumptions are reasonable.

LEGAL AND OTHER MATTERS

A discussion of LEGAL AND OTHER MATTERS is described in Note 17 of Notes to **DPL's** Consolidated Financial Statements and Note 14 of Notes to **DP&L's** Financial Statements. A discussion of environmental matters and competition and regulation matters affecting both **DPL** and **DP&L** is described in Item 1 – Environmental Considerations and Item 1 – Competition and Regulation. Such discussions are incorporated by reference in this Management's Discussion and Analysis of Financial Condition and Results of Operations and made a part hereof.

Recently Issued Accounting Pronouncements

A discussion of recently issued accounting pronouncements is described in Note 1 of Notes to **DPL's** Consolidated Financial Statements and Note 1 of Notes to **DP&L's** Financial Statements and such discussion is incorporated by reference in this Management's Discussion and Analysis of Financial Condition and Results of Operations and made a part hereof.

Item 7A – Quantitative and Qualitative Disclosures about Market Risk

The information required by this item of Form 10-K is set forth in the Market Risk section under Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 8 – Financial Statements and Supplementary Data

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.

Report of Independent Registered Public Accounting Firm

To the Board of Directors of DPL Inc.:

We have audited the accompanying Consolidated Balance Sheets of DPL Inc. as of December 31, 2012 and 2011, and the related Consolidated Statements of Operations, Comprehensive Income / (Loss), Cash Flows and Shareholders' Equity for the year ended December 31, 2012 and the period from November 28, 2011 through December 31, 2011. Our audits also included the consolidated financial statement schedule "Schedule II – Valuation and Qualifying Accounts" for the year ended December 31, 2012 and the period from November 28, 2011 through December 31, 2011. These consolidated financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of DPL Inc. at December 31, 2012 and 2011 and the consolidated results of its operations and its cash flows for the year ended December 31, 2012 and the period from November 28, 2011 through December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP
Cincinnati, Ohio
February 26, 2013

Report of Independent Registered Public Accounting Firm

The Board of Directors
DPL Inc.:

We have audited the accompanying consolidated statements of results of operations, comprehensive income / (loss), cash flows and shareholders' equity for DPL Inc and its subsidiaries (DPL) for the period from January 1, 2011 through November 27, 2011 and for the year ended December 31, 2010. In connection with our audits of the consolidated financial statements, we also have audited the consolidated financial statement schedule, "Schedule II – Valuation and Qualifying Accounts" for the period from January 1, 2011 through November 27, 2011 and for the year ended December 31, 2010. These consolidated financial statements and schedule are the responsibility of DPL's management. Our responsibility is to express an opinion on these consolidated financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of their operations and their cash flows for the period from January 1, 2011 through November 27, 2011 and for the year 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 consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

Philadelphia, Pennsylvania
March 27, 2012

DPL INC.
CONSOLIDATED STATEMENTS OF RESULTS OF OPERATIONS

	Successor		Predecessor	
$ in millions except per share amounts	**Year ended**	November 28, 2011	January 1, 2011 through	Year ended

	December 31, 2012	through December 31, 2011	November 27, 2011	December 31 2010
Revenues	**1,668.4**	156.9	1,670.9	1,831.4
Cost of revenues:				
Fuel	**361.9**	35.8	355.8	383.9
Purchased power	**342.1**	36.7	404.6	387.4
Amortization of intangibles	**95.1**	11.6	-	-
Total cost of revenues	**799.1**	84.1	760.4	771.3
Gross margin	**869.3**	72.8	910.5	1,060.1
Operating expenses:				
Operation and maintenance	**406.4**	47.5	377.8	340.6
Depreciation and amortization	**125.4**	11.6	129.4	139.4
General taxes	**79.5**	7.6	75.5	75.7
Goodwill impairment	**1,817.2**	-	-	-
Total operating expenses	**2,428.5**	66.7	582.7	555.7
Operating income / (loss)	**(1,559.2)**	6.1	327.8	504.4
Other income / (expense), net				
Investment income	**2.5**	0.1	0.4	1.8
Interest expense	**(122.9)**	(11.5)	(58.7)	(70.6
Charge for early redemption of debt	**-**	-	(15.3)	-
Other deductions	**(2.5)**	(0.3)	(1.7)	(2.3
Total other expense, net	**(122.9)**	(11.7)	(75.3)	(71.1
Earnings (loss) from operations before income tax	**(1,682.1)**	(5.6)	252.5	433.3
Income tax expense	**47.7**	0.6	102.0	143.0
Net income / (loss)	**(1,729.8)**	(6.2)	150.5	290.3
Average number of common shares outstanding (millions):				
Basic	**N/A**	N/A	114.5	115.6
Diluted	**N/A**	N/A	115.1	116.1
Earnings per share of common stock:				
Basic	**N/A**	N/A	1.31	2.51
Diluted	**N/A**	N/A	1.31	2.50
Dividends declared per share of common stock	**N/A**	N/A	1.54	1.21

See Notes to Consolidated Financial Statements.

DPL INC.
STATEMENTS OF COMPREHENSIVE INCOME / (LOSS)

	Successor		Predecessor	
$ in millions	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31, 2010
Net income / (loss)	**(1,729.8)**	(6.2)	150.5	290.3
Available-for-sale securities activity:				
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $(0.2), $0.0, $0.0 and $(0.2) for each respective period	**0.5**	-	-	0.4
Reclassification to earnings, net of immaterial tax effect	**(0.1)**	-	-	-
Total change in fair value of available-for-sale securities	**0.4**	-	-	**0.4**
Derivative activity:				
Change in derivative fair value, net of income tax benefit / (expense) of $1.4, $0.3, $31.2 and $(6.6) for each respective period	**(1.5)**	(0.5)	(58.2)	12.3
Reclassification to earnings, net of income tax benefit / (expense) of $0.4, $0.0, $(0.3) and $2.0 for each respective period	**(0.5)**	-	(0.3)	(5.9)
Total change in fair value of derivatives	**(2.0)**	(0.5)	(58.5)	6.4
Pension and postretirement activity:				
Prior Service Cost for the period, net of income tax benefit / (expense) of $0.0, $0.2, $0.0 and $(3.7) for each respective period	-	(0.2)	0.1	7.0
Net loss for the period, net of income tax benefit / (expense) of $1.0, $(0.2), $(0.7) and $4.0 for each respective period	**(1.9)**	0.3	0.3	(6.1)
Reclassification to earnings, net of income tax benefit / (expense) of $0.0, $0.0, $1.5 and $(1.3) for each respective period	-	-	2.8	2.4
Total change in unfunded pension and postretirement	**(1.9)**	0.1	3.2	3.3
Other comprehensive income / (loss)	**(3.5)**	(0.4)	(55.3)	10.1
Net comprehensive income / (loss)	**(1,733.3)**	(6.6)	95.2	300.4

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

$ in millions	Successor: Year ended December 31, 2012	Successor: November 28, 2011 through December 31, 2011	Predecessor: January 1, 2011 through November 27, 2011	Predecessor: Year ended December 31 2010
Cash flows from operating activities:				
Net income / (loss)	**(1,729.8)**	(6.2)	150.5	290.3
Adjustments to reconcile Net income (loss) to Net cash from operating activities				
Depreciation and amortization	**125.4**	11.6	129.4	139.4
Amortization of other assets	**95.1**	11.6	-	-
Amortization of debt market value adjustments	**(19.0)**	-	-	-
Deferred income taxes	**(4.2)**	0.1	65.5	59.9
Charge for early redemption of debt	-	-	15.3	-
Goodwill impairment	**1,817.2**	-	-	-
Recognition of deferred SECA revenue	**(17.8)**	-	-	-
Changes in certain assets and liabilities:				
Accounts receivable	**13.4**	(12.3)	14.6	(1.5
Inventories	**15.6**	(2.3)	(8.0)	12.4
Prepaid taxes	-	0.6	7.1	(9.0
Taxes applicable to subsequent years	**7.2**	(71.2)	58.4	(4.1
Deferred regulatory costs, net	**(1.1)**	0.1	(14.4)	21.8
Accounts payable	**(16.2)**	6.6	(0.6)	17.8
Accrued taxes payable	**5.1**	78.5	(58.6)	1.2
Accrued interest payable	**1.5**	6.4	(8.1)	(5.1
Pension, retiree and other benefits	**28.5**	10.2	(34.2)	(58.2
Unamortized investment tax credit	**(0.3)**	(0.2)	(2.3)	(2.8
Insurance and claims costs	**(2.8)**	(0.1)	4.3	(6.1
Other deferred debits, **DPL** stock held in trust	-	(26.9)	-	-
Other	**(26.3)**	(7.9)	15.5	17.1

Net cash from operating activities	**291.5**	(1.4)	334.4	473.1
Cash flows from investing activities:				
Capital expenditures	**(198.1)**	(30.5)	(174.2)	(152.7
Proceeds from sale of property - other	**1.1**	-	-	-
Purchase of emission allowances	**(0.1)**	-	(0.2)	(0.9
Purchase of renewable energy credits	**(5.4)**	(0.6)	(3.8)	(2.0
Purchase of MC Squared	-	-	(8.3)	-
Decrease / (increase) in restricted cash	**2.9**	1.0	(4.8)	(6.0
Purchases of short-term investments	-	-	(1.7)	(86.4
Sales of short-term investments	-	-	70.9	17.1
Other investing activities, net	**0.4**	(0.3)	1.4	1.4
Net cash from investing activities	**(199.2)**	(30.4)	(120.7)	(229.5

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

	Successor		Predecessor	
$ in millions	**Year ended December 31, 2012**	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31 2010
Cash flows from financing activities:				
Dividends paid on common stock	**(64.1)**	(63.0)	(113.0)	(139.7
Contributions to additional paid-in capital from parent	**0.3**	-	-	-
Repurchase of DPL common stock	-	-	-	(56.4
Payment to former warrant holders	**(9.0)**	-	-	-
Deferred finance costs	**(0.8)**	-	-	-
Proceeds from exercise of warrants	-	-	14.7	-
Proceeds from liquidation of DPL stock, held in trust	-	26.9	-	-
Retirement of long-term debt	**(0.1)**	-	(297.5)	-
Early redemption of Capital Trust II notes	-	-	(122.0)	-

Premium paid for early redemption of debt	-	-	(12.2)	-
Issuance of long-term debt	-	125.0	300.0	-
Payment of MC Squared debt	-	-	(13.5)	-
Borrowings from revolving credit facilities	-	-	50.0	-
Repayment of borrowings from revolving credit facilities	-	-	(50.0)	-
Exercise of stock options	-	-	1.6	1.4
Tax impact related to exercise of stock options	-	-	1.4	0.2
Net cash from financing activities	**(73.7)**	88.9	(240.5)	(194.5
Cash and cash equivalents:				
Net change	**18.6**	57.1	(26.8)	49.1
Assumption of cash at acquisition	-	19.2	-	-
Balance at beginning of period	**173.5**	97.2	124.0	74.9
Cash and cash equivalents at end of period	**192.1**	173.5	97.2	124.0
Supplemental cash flow information:				
Interest paid, net of amounts capitalized	**136.9**	6.0	62.0	77.1
Income taxes (refunded) / paid, net	**47.6**	-	25.6	87.1
Non-cash financing and investing activities:				
Accruals for capital expenditures	**16.7**	26.5	18.9	23.2
Long-term liability incurred for the purchase of plant assets	-	-	18.7	-
Assumption of debt with acquisition	-	1,250.0	-	-

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	**December 31, 2012**	December 31, 2011
ASSETS		

Current assets:		
Cash and cash equivalents	**192.1**	173.5
Restricted cash	**10.7**	13.6
Accounts receivable, net (Note 3)	**208.2**	219.1
Inventories (Note 3)	**110.1**	125.8
Taxes applicable to subsequent years	**69.3**	76.5
Regulatory assets, current (Note 4)	**21.1**	20.8
Other prepayments and current assets	**43.1**	38.0
Total current assets	**654.6**	667.3
Property, plant and equipment:		
Property, plant and equipment	**2,590.4**	2,360.3
Less: Accumulated depreciation and amortization	**(115.9)**	(7.5
	2,474.5	2,352.8
Construction work in process	**89.3**	152.3
Total net property, plant and equipment	**2,563.8**	2,505.1
Other non-current assets:		
Regulatory assets, non-current (Note 4)	**185.5**	193.2
Goodwill	**759.1**	2,576.3
Intangible assets, net of amortization (Note 6)	**50.1**	142.4
Other deferred assets	**34.2**	51.9
Total other non-current assets	**1,028.9**	2,963.8
Total Assets	**4,247.3**	6,136.2

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	**December 31, 2012**	December 31, 2011
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 7)	**584.9**	0.4
Accounts payable	**83.2**	111.1
Accrued taxes	**97.1**	63.2
Accrued interest	**31.8**	30.2
Customer security deposits	**15.0**	15.9
Regulatory liabilities, current (Note 4)	**0.1**	0.5
Insurance and claims costs	**11.5**	14.2
Other current liabilities	**96.9**	69.2
Total current liabilities	**920.5**	304.7
Non-current liabilities:		

Long-term debt (Note 7)	**2,025.0**	2,628.9
Deferred taxes (Note 8)	**534.9**	540.6
Taxes payable	**68.1**	96.9
Regulatory liabilities, non-current (Note 4)	**117.3**	118.6
Pension, retiree and other benefits	**61.6**	47.5
Unamortized investment tax credit	**3.3**	3.6
Other deferred credits	**71.4**	146.3
Total non-current liabilities	**2,881.6**	3,582.4
Redeemable preferred stock of subsidiary	**18.4**	18.4
Commitments and contingencies (Note 17)		
Common shareholder's equity:		
Common stock:		
1,500 shares authorized; 1 share issued and outstanding at December 31, 2012 and 2011	**2,236.7**	2,237.3
Accumulated other comprehensive loss	**(3.9)**	(0.4
Retained earnings / (deficit)	**(1,806.0)**	(6.2
Total common shareholder's equity	**426.8**	2,230.7
Total Liabilities and Shareholder's Equity	**4,247.3**	6,136.2

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock [b]							
$ in millions (except Outstanding Shares)	Outstanding Shares	Amount	Warrants	Common Stock Held by Employee Plans	Accumulated Other Comprehensive Income / (Loss)	Other Paid-in Capital	Retained Earnings	Total
Beginning balance	118,966,767	1.2	2.9	(19.3)	(29.0)	-	1,144.1	1,099.9
Year ended December 31, 2010 (Predecessor):								
Total comprehensive income (loss)					10.1		290.3	300.4
Common stock dividends [a]							(139.7)	(139.7
Repurchase of warrants			(0.2)					(0.2
Exercise of warrants	18,288							
Treasury stock purchased	(2,182,751)						(56.4)	(56.4
Treasury stock reissued	122,540						2.4	2.4

Tax effects to equity							0.2	0.2
Employee / Director stock plans				6.8			5.1	11.9
Ending balance	116,924,844	1.2	2.7	(12.5)	(18.9)	-	1,246.0	1,218.5
January 1, 2011 through November 27, 2011 (Predecessor)								
Total comprehensive income (loss)					(55.3)		150.5	95.2
Common stock dividends [a]							(176.0)	(176.0)
Repurchase of warrants			(1.1)					(1.1)
Treasury stock reissued	805,150						18.2	18.2
Tax effects to equity							1.4	1.4
Employee / Director stock plans				12.7			1.8	14.5
Other					(0.1)		(0.1)	(0.2)
Ending balance	117,729,994	1.2	1.6	0.2	(74.3)	-	1,241.8	1,170.5

DPL INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (continued)

$ in millions (except Outstanding Shares)	Common Stock [b] Outstanding Shares	Amount	Warrants	Common Stock Held by Employee Plans	Accumulated Other Comprehensive Income / (Loss)	Other Paid-in Capital	Retained Earnings	Total
November 28, 2011 through December 31, 2011 (Successor)								
Capitalization at Merger	1				-	2,235.6	-	2,235.6
Total comprehensive income (loss)					(0.4)		(6.2)	(6.6)
Contribution from parent						1.7		1.7
Ending balance	1	-	-	-	(0.4)	2,237.3	(6.2)	2,230.7
Year ended December 31, 2012 (Successor)								
Total comprehensive income (loss)					(3.5)		(1,729.8)	(1,733.3)
Common stock dividends [a]							(70.0)	(70.0)
Other						(0.6)		(0.6)
Ending balance	1	-	-	-	(3.9)	2,236.7	(1,806.0)	426.8

(a) Common stock dividends were $70.0 million in 2012, $1.54 per share in the period January 1, 2011 through November 27, 2011 and $1.21 per share in 2010.

(b) $0.01 par value, 250,000,000 shares authorized through November 27, 2011; 1,500 shares authorized from November 28, 2011 onwards.

See Notes to Financial Statements.

DPL Inc.
Notes to Consolidated Financial Statements

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 subsidiary. Refer to Note 18 for more information relating to these reportable segments. The terms "we," "us," "our" and "ours" are used to refer to **DPL** and its subsidiaries.

On November 28, 2011, **DPL** was acquired by AES in the Merger and **DPL** became a wholly-owned subsidiary of AES. See Note 2. Following the merger of **DPL** and Dolphin Subsidiary II, Inc., **DPL** became an indirectly wholly-owned subsidiary of AES.

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 electric generating stations and is distributed to more than 513,000 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 198,000 customers currently located throughout Ohio and Illinois. Approximately 74,000 of DPLER's customers are also electric distribution customers of **DP&L**. 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 area.

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 other 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 1,486 people as of December 31, 2012, of which 1,428 employees were employed by **DP&L**. Approximately 52% of all **DPL** employees are under a collective bargaining agreement which expires on October 31, 2014.

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's** undivided ownership interests in certain coal-fired generating stations are included in the financial statements at amortized cost, which was adjusted to fair value at the Merger date. Operating revenues and expenses are included on a pro rata basis in the corresponding lines in the Consolidated Statement of Operations. See Note 5 for more information.

Deferred SECA revenue of $17.8 million at December 31, 2011 was reclassified from Regulatory liabilities to Other deferred credits. The FERC approved SECA billings were unearned revenue where the earnings process was not complete. 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 $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; at December 31, 2012 there is no remaining balance in other deferred credits related to SECA. See Note 17 for more information relating to SECA.

Certain immaterial amounts from prior periods, including derivative assets and liabilities and restricted cash, have been reclassified to conform to the current period 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; 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 indirect wholly-owned subsidiary of AES. **DPL's** basis of accounting incorporates the application of FASC 805, "Business Combinations" (FASC 805) as of the Merger date. FASC 805 required the acquirer to recognize and measure identifiable assets acquired and liabilities assumed at fair value as of the Merger date. **DPL's** 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. See Note 2 for additional information. AES finalized its purchase price allocation during the third quarter of 2012.

As a result of the push down accounting, **DPL's** 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. See Note 2 for additional information.

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, after adjustments. 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; 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 estimated impairment charge of $1,850.0 million against the goodwill at **DPL's** DP&L Reporting Unit. This was adjusted to $1,817.2 million in the fourth quarter of 2012. See Note 19 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 electric security plan. See Note 6 for more information.

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 stations 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.

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 year ended December 31, 2012 was $15.7 million. In addition, MC Squared sells receivables from their customers in ComEd territory to ComEd. Total receivables sold during the year ended December 31, 2012 was $27.7 million.

Property, Plant and Equipment

We record our ownership share of our undivided interest in jointly-held stations as an asset in property, plant and equipment. New property, plant and equipment additions 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 $4.0 million, $0.5 million, $3.9 million and $3.4 million in the year ended December 31, 2012, the period from November 28, 2011 through December 31, 2011, the period January 1, 2011 through November 27, 2011, and the year ended December 31, 2010, 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.

Repairs and Maintenance

Costs associated with maintenance activities, primarily power station 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 – Changes in Estimates

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, 2010, 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. During

the year ended December 31, 2011, the net reduction in depreciation expense amounted to $4.8 million ($3.1 million net of tax) compared to the prior year. On an annualized basis, the net reduction in depreciation expense is projected to be approximately $9.6 million ($6.2 million net of tax).

For **DPL's** generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 4.8% in 2012, 5.8% in 2011 and 2.6% in 2010.

The following is a summary of **DPL's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2012 and 2011:

$ in millions	2012	Composite Rate	2011	Composite Rate
	At December 31,			
Regulated:				
Transmission	**208.9**	**4.4%**	189.5	4.8%
Distribution	**935.0**	**5.4%**	803.0	5.8%
General	**50.6**	**10.8%**	26.3	13.1%
Non-depreciable	**60.0**	**N/A**	59.7	N/A
Total regulated	**1,254.5**		1,078.5	
Unregulated:				
Production / Generation	**1,299.7**	**4.4%**	1,248.0	6.0%
Other	**16.6**	**11.6%**	14.4	10.1%
Non-depreciable	**19.6**	**N/A**	19.4	N/A
Total unregulated	**1,335.9**		1,281.8	
Total property, plant and equipment in service	**2,590.4**	**4.8%**	2,360.3	5.8%

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 consists 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

The balance at November 28, 2011 has been adjusted to reflect the effect of the purchase accounting.

$ in millions	
January 1, 2011 through November 27, 2011 (Predecessor)	
Balance at January 1, 2011	17.5
Accretion expense	0.8
Additions	-
Settlements	(0.4

Estimated cash flow revisions	0.9
Balance at November 27, 2011	18.8
November 28, 2011 through December 31, 2011 (Successor)	
Balance at November 28, 2011	23.6
Accretion expense	-
Additions	-
Settlements	(0.1
Estimated cash flow revisions	0.1
Balance at December 31, 2011	23.6
Calendar 2012 (Successor)	
Accretion expense	0.8
Additions	-
Settlements	(0.4
Estimated cash flow revisions	(0.1
Balance at December 31, 2012	23.9

Asset Removal Costs

We continue to record costs 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 $112.1 million and $112.4 million in estimated costs of removal at December 31, 2012 and 2011, 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 4 for additional information.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

No adjustment was necessary at November 28, 2011 for purchase accounting since these are associated with the actions of a regulator.

$ in millions	
January 1, 2011 through November 27, 2011 (Predecessor)	
Balance at January 1, 2011	107.9
Additions	8.6
Settlements	(4.3
Balance at November 27, 2011	112.2
November 28, 2011 through December 31, 2011 (Successor)	
Balance at November 28, 2011	112.2
Additions	0.8
Settlements	(0.6
Balance at December 31, 2011	112.4
Calendar 2012 (Successor)	
Additions	10.1
Settlements	(10.4
Balance at December 31, 2012	112.1

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 4 for more information about Regulatory Assets and Liabilities.

Effective November 28, 2011, Regulatory assets and liabilities are presented on a current and non-current basis, depending on the term recovery is anticipated. This change was made to conform with AES' presentation of Regulatory assets and liabilities.

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.

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. 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 are amortized over nine to fifteen 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. See Note 6 for additional information.

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.

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.

As a result of the Merger, **DPL** and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, **DPL** and its subsidiaries filed a consolidated U.S. federal income tax return. 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 8 for additional information.

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, from time to time, 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 utilizes 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 net basis and recorded as a reduction in revenues in the accompanying Statements of Results of Operations. These and certain other taxes are accounted for on a net basis and recorded as a reduction in revenues. The amounts for the year ended December 31, 2012, the period November 28, 2011 through December 31, 2011, the period January 1, 2011 through November 27, 2011, and the year ended December 31, 2010 were $50.5 million, $4.3 million, $49.4 million and $51.7 million, respectively.

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 12 for additional information. As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date, and none are in existence at December 31, 2012 or 2011.

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.

Restricted Cash

Restricted cash includes cash which is restricted as to withdrawal or usage. The nature of the restrictions include restrictions imposed by agreements related to deposits held as collateral.

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 the derivative is designated as a cash flow hedge of a forecasted transaction or it qualifies 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. We have elected not to offset net derivative positions in the financial statements. Accordingly, we do not offset such derivative positions against the fair value of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral under master netting agreements. See Note 11 for additional information.

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.

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 estimated liabilities for insurance and claims costs of approximately $11.5 million and $14.2 million at December 31, 2012 and 2011, 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 estimated liabilities for 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 $17.7 million and $18.9 million for 2012 and 2011, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for MVIC at **DPL** and the estimated liabilities for workers' compensation, medical, life and disability costs at **DP&L** are actuarially determined based on a reasonable estimation of insured events occurring and any payments related to those events. 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 in 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 $0.5 million and $3.6 million at December 31, 2012 and 2011, respectively, is included in Other deferred assets within Other noncurrent assets. **DPL** also has a note payable to the Trust amounting to $19.6 million and $19.5 million at December 31, 2012 and 2011 that was established upon the Trust's deconsolidation in 2003. See Note 7 for additional information.

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.

<u>Recently Adopted Accounting Standards</u>

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. These new rules did not have a material effect on our overall results of operations, financial position or cash flows.

Recently Issued Accounting Standards

The FASB recently issued ASU 2013-01, "Scope Clarification of Disclosures about Offsetting Assets and Liabilities", to limit the scope of ASU 2011-11 "Disclosures about Offsetting Assets and Liabilities" to derivatives (including bifurcated embedded derivatives), repurchase agreements and reverse repurchase agreements, and securities borrowing and lending transactions. This ASU is effective for annual and interim periods beginning on or after January 1, 2013. The FASB clarified that the disclosures were not intended to include trade receivables and other contracts for financial instruments that may be subject to a master netting arrangement. This new rule is not expected to have a material effect on our overall results of operations, financial position or cash flows.

The FASB recently issued ASU 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income" effective for annual and interim periods beginning after December 15, 2012. The ASU does not change the current requirements for reporting net income or other comprehensive income in financial statements. However, the ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This new rule is not expected to have a material effect on our overall results of operations, financial position or cash flows.

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 [(a)]	(70.7)	25.5
DPLER intangibles [(b)]	(19.1)	6.7
Out of market coal contract [(c)]	(34.2)	12.0
Deferred tax liabilities [(d)]	-	(20.7)
Regulatory assets [(e)]	15.4	-
Taxes payable [(f)]	13.1	(16.0)
Other	1.0	-
	(94.5)	7.5
Net (increase) in goodwill		(87.0)

(a) related to refined information associated with certain contractual arrangements, growth and ancillary revenue assumptions.

(b) related to refined market and contractual information.

(c) related to a change in certain assumptions related to an out of market coal contract.

(d) related to an assessment of our overall deferred tax liabilities on regulated property, plant and equipment.

(e) related to the increase in deferred taxes discussed in (d) above.

(f) related to the final 2011 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	December 31, 2012	2011
Accounts receivable, net		
Unbilled revenue	**75.2**	72.4
Customer receivables	**98.2**	113.2
Amounts due from partners in jointly-owned stations	**19.7**	29.2
Coal sales	**1.6**	1.0
Other	**14.6**	4.4
Provisions for uncollectible accounts	**(1.1)**	(1.1
Total accounts receivable, net	**208.2**	219.1
Inventories		
Fuel and limestone	**67.3**	84.2
Plant materials and supplies	**41.0**	39.8
Other	**1.8**	1.8
Total inventories, at average cost	**110.1**	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 December 31, 2012 and 2011:

$ in millions (net of tax)	December 31, 2012	2011
Financial instruments	**0.4**	-
Cash flow hedges	**(2.5)**	(0.5
Pension and postretirement benefits	**(1.8)**	0.1
Total	**(3.9)**	(0.4

4. 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 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	December 31, 2012	2011
Regulatory assets, current:				
TCRR, transmission, ancillary and other PJM-related costs	F	Ongoing	**7.0**	4.7
Power plant emission fees	C	Ongoing	**-**	4.8
Fuel and purchased power recovery costs	C	Ongoing	**14.1**	11.3
Total regulatory assets, current			**21.1**	20.8
Regulatory assets, non-current:				
Deferred recoverable income taxes	B/C	Ongoing	**35.1**	39.5
Pension benefits	C	Ongoing	**88.9**	92.1
Unamortized loss on reacquired debt	C	Ongoing	**11.9**	13.0
Regional transmission organization costs	D	2014	**2.6**	4.1
Deferred storm costs	D		**24.4**	17.9
CCEM smart grid and advanced metering infrastructure costs	D		**6.6**	6.6
CCEM energy efficiency program costs	F	Ongoing	**5.2**	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			**185.5**	193.2
Regulatory liabilities, current:				
Fuel and purchased power recovery costs	C	Ongoing	**0.1**	0.5
Total regulatory liabilities, current			**0.1**	0.5
Regulatory liabilities, non-current:				

Estimated costs of removal - regulated property	**112.1**	112.4
Postretirement benefits	**5.0**	6.2
Other	**0.2**	-
Total regulatory liabilities, non-current	**117.3**	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 $3.4 million from certain transactions. On October 4, 2012, we filed testimony on this issue and a hearing was scheduled. In December 2012, we agreed to an immaterial adjustment to settle these issues. The liability was recorded in the fourth quarter of 2012 and will be credited to customers in early 2013.

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 relate to costs incurred to repair the damage caused by storms in the following years:

- 2008 – related to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other 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.
- 2011 – related to five major storms in 2011. On December 21, 2012, **DP&L** filed a request with the PUCO for an accounting order to defer costs and a request for recovery of costs associated with these storms. **DP&L** believes the recovery of these costs is probable at December 31, 2012.
- 2012 – related to storm damage that occurred during the final weekend of June 2012. On August 10, 2012, **DP&L** filed a request with the PUCO, which was modified on October 19, 2012, for an accounting order to defer the costs associated with this storm damage. On December 19, 2012, the PUCO issued an order permitting partial deferral.

  On December 21, 2012, **DP&L** filed a request for recovery of all of these deferred storm costs with the PUCO.

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 that 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 with 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

Fuel and purchased power recovery 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 $3.4 million from certain transactions. On October 4, 2012, we filed testimony on this issue and a hearing was scheduled. In December 2012, we agreed to an immaterial adjustment to settle these issues. The liability was recorded in the fourth quarter of 2012 and will be credited to customers in early 2013.

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.

5. Ownership of Coal-fired Facilities

DP&L and certain 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, 2012, **DP&L** had $36.0 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 within Total net property, plant and equipment in the 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 December 31, 2012, is as follows:

	DP&L Share		**DP&L** Investment (adjusted to fair value as of Merger date)			
	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)
Jointly-owned production units						
Beckjord Unit 6	50.0	207	-	-	-	No
Conesville Unit 4	16.5	129	41	3	11	Yes
East Bend Station	31.0	186	8	2	3	Yes
Killen Station	67.0	402	299	-	5	Yes
Miami Fort Units 7 and 8	36.0	368	213	7	3	Yes
Stuart Station	35.0	808	200	6	12	Yes
Zimmer Station	28.1	365	169	12	2	Yes
Transmission (at varying percentages)			39	3	-	
Total		2,465	969	33	36	
Wholly-owned production unit						
Hutchings Station	100.0	365	-	-	-	No

Currently, our coal-fired generation units at Hutchings and Beckjord do not have the 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 commonly owned Unit 6, in December 2014. This was followed by a notification by the joint owners of Beckjord Unit 6 to PJM, dated April 12, 2012, of a planned June 1, 2015 deactivation of this unit. Beckjord Unit 6 was valued at zero at the Merger date.

DP&L has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated June 1, 2013. In addition, **DP&L** has notified PJM that the remaining units at Hutchings will no longer operate after May 2013 and will be deactivated on June 1, 2015. The decision to deactivate these units has been made because these 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 final rule was issued on December 16, 2011. Hutchings was valued at zero at the Merger date. We do not believe that any additional accruals are needed related to the Hutchings Station.

6. Goodwill and Other Intangible Assets

Goodwill represents the value assigned at the Merger date, as adjusted for subsequent changes in the purchase price allocation, less recognized impairments. In the third quarter of 2012, **DPL** recognized an impairment of goodwill in the estimated amount of $1,850.0 million. The valuation of the goodwill impairment was completed in the fourth quarter of 2012 and the final impairment was $1,817.2 million. See Note 19 for more information about this impairment.

The following table summarizes the changes in Goodwill:

$ in millions	DP&L Reporting Unit	DPLER Reporting Unit	Total
Balance at December 31, 2010			
Goodwill	-	-	-
Accumulated impairment losses	-	-	-
Net balance at December 31, 2010	-	-	-
Goodwill acquired during the year	2,440.5	135.8	2,576.3
Impairment losses	-	-	-
Balance at December 31, 2011			
Goodwill	2,440.5	135.8	2,576.3
Accumulated impairment losses	-	-	-
Net balance at December 31, 2011	2,440.5	135.8	2,576.3
Impairment losses	(1,817.2)	-	(1,817.2

Balance at December 31, 2012			
Goodwill	2,440.5	135.8	2,576.3
Accumulated impairment losses	(1,817.2)	-	(1,817.2)
Net balance at December 31, 2012	623.3	135.8	759.1

The following tables summarize the balances comprising intangible assets as of December 31, 2012:

$ in millions	**December 31, 2012**			December 31, 2011		
	Gross Balance	**Accumulated Amortization**	**Net Balance**	Gross Balance	Accumulated Amortization	Net Balance
Subject to Amortization						
Electric Security Plan [a]	**87.0**	**(87.0)**	**-**	87.0	(8.6)	78.4
Customer Contracts [b]	**28.0**	**(19.7)**	**8.3**	28.0	(3.0)	25.0
Customer Relationships [c]	**31.8**	**(1.1)**	**30.7**	31.8	(0.5)	31.3
Other [d]	**5.3**	**(0.3)**	**5.0**	2.8	(1.2)	1.6
	152.1	**(108.1)**	**44.0**	149.6	(13.3)	136.3
Not subject to Amortization						
Trademark/Trade name [e]	**6.1**	**-**	**6.1**	6.1	-	6.1
Total intangibles	**158.2**	**(108.1)**	**50.1**	155.7	(13.3)	142.4

During 2012, $1.1 million of intangibles related to the MC Squared Trademark/Trade name was reclassified from Subject to Amortization to Not subject to Amortization. This reclassification was also reflected in the 2011 amounts above.

(a) Represents the value of DP&L's Electric Security Plan which is a rate plan for the supply and pricing of electric generation services. It provides a level of price stability to consumers of electricity compared to market-based electricity prices.

(b) Represents above market contracts that DPLER has with third party customers existing as of the Merger date.

(c) Represents relationships DPLER has with third party customers as of the Merger date, where DPLER has regular contact with the customer, and the customer has the ability to make direct contact with DPLER.

(d) Consists of various intangible assets including renewable energy credits, emission allowances, and other intangibles, none of which are individually significant.

(e) Trademark/Trade name represents the value assigned to the trade names of DPLER and MC Squared.

The following table summarizes, by category, intangible assets acquired during the period ended December 31, 2012:

$ in millions	Amoun t	Subject to Amortization/ Indefinite-lived	Weighte d Average Amortization Period (years)	Amortiz tion Method
Renewable Energy Certificates	5.4	Subject to amortization	Various	As Utilized
Emission Allowances	0.1	Subject to amortization	Various	As Utilized
	5.5			

The following table summarizes the amortization expense, broken down by intangible asset category for 2013 through 2017:

	Estimated amortization expense				
	Years ending December 31,				
$ in millions	2013	2014	2015	2016	2017
Customer contracts	7.1	1.2	-	-	-
Customer relationships	3.4	3.8	3.8	3.1	2.7
Other	0.5	4.1	0.4	-	-
	11.0	9.1	4.2	3.1	2.7

7. Debt Obligations

Long-term debt

$ in millions	**December 31, 2012**	December 31, 2011
First mortgage bonds maturing in October 2013 - 5.125%	-	503.6
Pollution control series maturing in January 2028 - 4.7%	**36.1**	36.1
Pollution control series maturing in January 2034 - 4.8%	**179.6**	179.6
Pollution control series maturing in September 2036 - 4.8%	**96.3**	96.2
Pollution control series maturing in November 2040 - variable rates: 0.04% - 0.26% and 0.06% - 0.32% (a)	-	100.0
U.S. Government note maturing in February 2061 - 4.2%	**18.3**	18.5
Capital lease obligations	**0.1**	0.4
Total long-term debt at subsidiary	**330.4**	934.4
Bank term loan-maturing in August 2014 - variable rates: 1.48% - 4.25% and 2.22% - 2.47% (a)	**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	**19.6**	19.5

2031 - 8.125%		
Total long-term debt	**2,025.0**	2,628.9

Current portion - long-term debt

$ in millions	**December 31, 2012**	December 31, 2011
First mortgage bonds maturing in October 2013 - 5.125%	**484.5**	-
Pollution control series maturing in November 2040 - variable rates: 0.04% - 0.26% and 0.06% - 0.32% (a)	**100.0**	-
U.S. Government note maturing in February 2061 - 4.2%	**0.1**	0.1
Capital lease obligations	**0.3**	0.3
Total current portion - long-term debt	**584.9**	0.4

(a) - range of interest rates for the twelve months ended December 31, 2012 and December 31, 2011, respectively

The presentation above for the Successor is based on the revaluation of the debt at the Merger date. At December 31, 2012, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions	
Due within one year	570.4
Due within two years	425.2
Due within three years	0.1
Due within four years	450.1
Due within five years	0.1
Thereafter	1,152.8
	2,598.7
Unamortized discounts and premiums, net	11.2
Total long-term debt	2,609.9

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

On November 21, 2006, **DP&L** entered into a $220.0 million unsecured revolving credit agreement. This agreement was terminated by **DP&L** on August 29, 2011.

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. If the letter of credit expires, this would trigger a mandatory tender of all of the outstanding bonds, therefore, we have reflected these outstanding bonds as a current liability. Management will continue to monitor and evaluate market conditions over the next several months and make a determination to either seek a renewal of this standby letter of credit or to explore alternative financing arrangements. Fees associated with this letter of credit facility were not material during the year ended December 31, 2012, the period November 28, 2011 through December 31, 2011, the period January 1, 2011 through November 27, 2011, or the year ended December 31, 2010.

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 December 31, 2012. Fees associated with this revolving credit facility were not material during the period between April 20, 2010 and December 31, 2012. This facility also contains a $50.0 million letter of credit sublimit. As of December 31, 2012, **DP&L** had no outstanding letters of credit against the facility.

On February 23, 2011, **DPL** redeemed $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 $12.2 million, or 10%, premium. Debt issuance costs and unamortized debt discount totaling $3.1 million were also recognized in February 2011 associated 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 (WPAFB). **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 December 31, 2012 or 2011. Fees associated with this revolving credit facility were not material during the year ended December 31, 2012 or the five months ended December 31, 2011. This facility also contains a $50.0 million letter of credit sublimit. As of December 31, 2012, **DP&L** had no outstanding letters of credit against the 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 December 31, 2012. Fees associated with this revolving credit facility were not material during the twelve months ended December 31, 2012. This facility may also be used to issue letters of credit up to the $75.0 million limit. As of December 31, 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. **DPL** has borrowed the entire $425.0 million available under the facility at December 31, 2012. Fees associated with this term loan were not material during the year ended December 31, 2012 or the five months ended December 31, 2011.

On September 1, 2011 **DPL** retired $297.4 million of 6.875% senior unsecured notes that had matured.

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. At December 31, 2012, we met this covenant.

The second financial covenant is a consolidated Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) to Interest Expense ratio. The EBITDA to Interest Expense ratio is calculated, at the end of each fiscal quarter, by dividing for the four prior fiscal quarters by the consolidated interest charges for the same period. At December 31, 2012, we met this covenant.

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 $1.25 billion of debt that Dolphin Subsidiary II, Inc., a subsidiary of AES, issued on October 3, 2011 to finance a portion of the Merger. The $1.25 billion was issued in two tranches. The first tranche was $450.0 million of five year senior unsecured notes issued at 6.50% maturing on October 15, 2016. The second tranche was $800.0 million of ten year senior unsecured notes issued at 7.25% 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.

8. Income Taxes

DPL's components of income tax expense were as follows:

$ in millions	Successor: Year ended December 31, 2012	Successor: November 28, 2011 through December 31, 2011	Predecessor: January 1, 2011 through November 27, 2011	Predecessor: Year ended December 31 2010
Computation of tax expense				
Federal income tax expense / (benefit)[(a)]	**(588.7)**	(2.0)	88.4	151.7
Increases (decreases) in tax resulting from:				
State income taxes, net of federal effect	**3.5**	0.1	3.8	2.4
Depreciation of AFUDC - Equity	**(2.4)**	(0.3)	(2.9)	(2.2
Investment tax credit amortized	**(0.3)**	(0.2)	(2.3)	(2.8
Section 199 - domestic production deduction	**(2.1)**	-	(3.6)	(9.1
Non-deductible merger costs	**-**	0.1	6.0	-
Non-deductible merger-related compensation	**0.6**	3.5	-	-
Non-deductible goodwill impairment	**636.0**	-	-	-
Derivatives	-	(0.1)	-	-
Compensation and benefits	-	-	13.8	0.4
Income not subject to tax	-	(0.6)	-	-
Other, net [(b)]	**1.1**	0.1	(1.2)	2.6
Total tax expense	**47.7**	0.6	102.0	143.0
Components of tax expense				
Federal - current	**48.6**	0.4	53.2	84.8
State and Local - current	**1.2**	0.4	0.9	1.1
Total current	**49.8**	0.8	54.1	85.9
Federal - deferred	**(4.9)**	(0.2)	43.2	55.9
State and local - deferred	**2.8**	-	4.7	1.2
Total deferred	**(2.1)**	(0.2)	47.9	57.1
Total tax expense	**47.7**	0.6	102.0	143.0

Components of Deferred Tax Assets and Liabilities (Successor)

$ in millions	December 31, 2012	December 31, 2011

Net non-current Assets / (Liabilities)		
Depreciation / property basis	**(517.0)**	(489.8)
Income taxes recoverable	**(12.3)**	(24.0)
Regulatory assets	**(20.6)**	(23.5)
Investment tax credit	**1.2**	10.5
Intangibles	**(2.4)**	(51.3)
Compensation and employee benefits	**2.2**	(0.8)
Long-term debt	**(2.0)**	13.2
Other [(c)]	**16.0**	25.1
Net non-current liabilities	**(534.9)**	(540.6)
Net current Assets / (Liabilities) [(d)]		
Other	**4.7**	(0.8)
Net current assets / (liabilities)	**4.7**	(0.8)

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

(b) Includes expense of $1.2 million and benefits of $0.0 million, $2.3 million and $0.3 million in the year ended December 31, 2012, the period November 28, 2011 through December 31, 2011, the period January 1, 2011 through November 27, 2011 and the year ended December 31, 2010, respectively, of income tax related to adjustments from prior years.

(c) The Other non-current liabilities caption includes deferred tax assets of $20.4 million in 2012 and $15.4 million in 2011 related to state and local tax net operating loss carryforwards, net of related valuation allowances of $16.2 million in 2012 and $6.7 million in 2011. These net operating loss carryforwards expire from 2013 to 2026.

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

The following table presents the tax expense / (benefit) related to pensions, postretirement benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

	Successor		Predecessor	
$ in millions	**Year ended December 31, 2012**	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31 2010
Tax expense / (benefit)	**(2.5)**	(1.2)	(33.2)	5.8

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 is as follows:

$ in millions	
2010 (Predecessor)	
Balance at January 1, 2010	19.3

Tax positions taken during prior periods	(0.4
Tax positions taken during current period	-
Settlement with taxing authorities	0.3
Lapse of applicable statute of limitations	0.2
Balance at December 31, 2010	19.4
January 1, 2011 through November 27, 2011 (Predecessor)	
Tax positions taken during prior periods	2.0
Settlement with taxing authorities	3.5
Balance at November 27, 2011	24.9
November 28, 2011 through December 31, 2011 (Successor)	
Balance at November 28, 2011	24.9
Tax positions taken during current period	0.1
Balance at December 31, 2011	25.0
2012 (Successor)	
Tax positions taken during prior period	(6.3
Tax positions taken during current period	(0.4
Balance at December 31, 2012	18.3

Of the December 31, 2012 balance of unrecognized tax benefits, $19.4 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 following table represents the amounts accrued as well as the expense / (benefit) recorded as of and for the periods noted below:

Amounts in Balance Sheet	**Successor**	
$ in millions	**December 31, 2012**	December 31, 2011
Liability / (asset)	**0.8**	0.9

Amounts in Statement of Operations	**Successor**		**Predecessor**	
$ in millions	**Year ended December 31, 2012**	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31 2010
Expense / (benefit)	**(0.1)**	-	0.6	0.2

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

U.S. Federal – 2007 and forward

State and Local – 2007 and forward

All of the unrecognized tax benefits are expected to be settled 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 was completed on January 18, 2013 and we do not expect the results of this examination to have a material effect on our financial condition, results of operations and cash flows.

As a result of the Merger, **DPL** and its subsidiaries file U.S. federal income tax returns as a part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, **DPL** and its subsidiaries filed a consolidated U.S. federal income tax return. 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.

9. Pension and Postretirement Benefits

DP&L sponsors a traditional defined benefit pension plan for most of the employees of **DPL** and its subsidiaries. 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 traditional defined benefit pension plan is based primarily on compensation and years of service. As of December 31, 2010, this traditional 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 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.

Almost all management employees beginning employment on or after January 1, 2011 participate in a cash balance pension plan. Similar to the traditional 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 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 retired key executives. The SERP was replaced by the DPL Inc. Supplemental Executive Defined Contribution Retirement Plan (SEDCRP) effective January 1, 2006, which is for certain active and former key executives. 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. Per the SEDCRP plan document, the balances in the SEDCRP, including earnings on contributions, were paid out to participants in December 2011, following the merger with AES on November 28, 2011. However, the SEDCRP continued and a 2011 contribution was calculated in March 2012. The SEDCRP was terminated by the Board of Directors as of December 31, 2012, but a 2012 contribution will be calculated and the balances, including earnings on contributions, will be paid to participants in 2013. 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 $1.1 million and $0.8 million at December 31, 2012 and 2011, 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. **DP&L** made discretionary contributions of $40.0 million and $40.0 million to the defined benefit plan during the period January 1, 2011 through November 27, 2011 and the year ended December 31, 2010, respectively.

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.

We recognize an asset for a plan's overfunded status and 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. For the transmission and distribution areas of our electric business, these amounts are recorded as regulatory assets and liabilities which 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 through customer rates. 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, 2012 and 2011. The amounts presented in the following tables for pension include the collective bargaining plan formula, traditional management plan formula and cash balance plan formula and the SERP in the aggregate. The amounts presented for postretirement include both health and life insurance benefits.

$ in millions	Pension		
	Successor		Predeces sor
	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Change in benefit obligation			
Benefit obligation at beginning of period	**365.2**	365.0	333.8
Service cost	**6.2**	0.5	4.5
Interest cost	**17.3**	1.5	15.5
Plan amendments	**-**	-	7.2
Actuarial loss	**29.1**	-	21.6
Benefits paid	**(22.2)**	(1.8)	(17.6
Benefit obligation at end of period	**395.6**	365.2	365.0
Change in plan assets			
Fair value of plan assets at beginning of period	**335.9**	335.8	291.8
Actual return on plan assets	**46.2**	1.9	21.2
Contributions to plan assets	**1.5**	-	40.4
Benefits paid	**(22.2)**	(1.8)	(17.6
Fair value of plan assets at end of period	**361.4**	335.9	335.8
Funded status of plan	**(34.2)**	(29.3)	(29.2

$ in millions	Postretirement		
	Successor		Predeces sor
	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Change in benefit obligation			
Benefit obligation at beginning of period	**21.7**	21.9	23.7
Service cost	**0.1**	-	0.1
Interest cost	**0.9**	0.1	0.9
Actuarial (gain) / loss	**1.2**	(0.1)	(1.3
Benefits paid	**(1.7)**	(0.2)	(1.8
Medicare Part D reimbursement	**0.2**	-	0.3
Benefit obligation at end of period	**22.4**	21.7	21.9
Change in plan assets			
Fair value of plan assets at beginning of period	**4.5**	4.5	4.8

Actual return on plan assets	**0.2**	-	0.2
Contributions to plan assets	**1.2**	0.2	1.3
Benefits paid	**(1.7)**	(0.2)	(1.8
Fair value of plan assets at end of period	**4.2**	4.5	4.5
Funded status of plan	**(18.2)**	(17.2)	(17.4

$ in millions	Pension		Postretirement	
	December 31,		December 31,	
	2012	2011	**2012**	2011
Amounts recognized in the Balance sheets at December 31				
Current liabilities	**(0.4)**	(1.3)	**(0.6)**	(0.6
Non-current liabilities	**(33.8)**	(27.9)	**(17.6)**	(16.6
Net liability at December 31	**(34.2)**	(29.2)	**(18.2)**	(17.2
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost	**10.3**	12.5	**0.5**	0.7
Net actuarial loss / (gain)	**79.9**	78.7	**(4.5)**	(6.4
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**90.2**	91.2	**(4.0)**	(5.7
Recorded as:				
Regulatory asset	**88.0**	91.2	**0.5**	0.5
Regulatory liability	**-**	-	**(5.0)**	(6.2
Accumulated other comprehensive income	**2.2**	-	**0.5**	-
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**90.2**	91.2	**(4.0)**	(5.7

The accumulated benefit obligation for our defined benefit pension plans was $382.5 million and $355.5 million at December 31, 2012 and 2011, respectively.

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

Net Periodic Benefit Cost - Pension	**Successor**	**Predecessor**

$ in millions	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31 2010
Service cost	**6.2**	0.5	4.5	4.8
Interest cost	**17.3**	1.5	15.5	17.7
Expected return on assets [(a)]	**(22.7)**	(2.0)	(22.5)	(22.4
Amortization of unrecognized:				
Actuarial loss	**5.0**	0.4	7.6	7.2
Prior service cost	**1.5**	0.1	2.0	3.7
Net periodic benefit cost before adjustments	**7.3**	0.5	7.1	11.0

Net Periodic Benefit Cost / (Income) - Postretirement	**Successor**		**Predecessor**	
$ in millions	**Year ended December 31, 2012**	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31 2010
Service cost	**0.1**	-	0.1	0.1
Interest cost	**0.9**	0.1	0.9	1.2
Expected return on assets [(a)]	**(0.3)**	-	(0.3)	(0.3
Amortization of unrecognized:				
Actuarial gain	**(0.6)**	-	(1.0)	(1.1
Prior service cost	**-**	(0.1)	0.1	0.1
Net periodic benefit cost / (income) before adjustments	**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 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 $346.0 million in 2012, $335.0 million in 2011, and $274.0 million in 2010.

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

Pension	**Successor**		**Predecessor**	
$ in millions	**Year ended**	November 28, 2011	January 1, 2011	Year ended

	December 31, 2012	through December 31, 2011	through November 27, 2011	December 31 2010
Net actuarial loss / (gain)	**5.5**	-	(38.7)	1.9
Prior service credit	-	-	(2.2)	-
Reversal of amortization item:				
Net actuarial gain	**(5.0)**	(0.4)	(7.6)	(7.2
Prior service credit	**(1.5)**	(0.1)	(2.0)	(3.7
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**(1.0)**	(0.5)	(50.5)	(9.0
Total recognized in net periodic benefit cost Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**6.3**	(0.5)	(43.4)	2.0

Postretirement	**Successor**		**Predecessor**	
$ in millions	**Year ended December 31, 2012**	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31 2010
Net actuarial loss / (gain)	**1.0**	-	0.2	(1.9
Prior service cost / (credit)	-	0.1	(0.1)	-
Reversal of amortization item:				
Net actuarial loss	**0.7**	-	1.0	1.1
Prior service credit	-	-	(0.1)	(0.1
Transition asset	-	(0.1)	-	-
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**1.7**	-	1.0	(0.9
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**1.8**	-	0.8	(0.9

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2013 are:

$ in millions	Pension	Postretirement
Net actuarial loss / (gain)	4.9	(0.5
Prior service cost	1.5	-

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 2013, we are maintaining our expected long-term rate of return on assets assumption of 7.00% for pension plan assets and 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 Aon Hewitt AA Above Median Yield Curve which represents a portfolio of above median 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 during December 31, 2012, 2011 and 2010 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2012	2011	2010	**2012**	2011	2010
Discount rate for obligations	**4.04 %**	4.88 %	5.31 %	**3.75 %**	4.62 %	4.96 %
Rate of compensation increases	**3.94 %**	3.94 %	3.94 %	**N/A**	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2012, 2011 and 2010 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2012	2011	2010	**2012**	2011	2010
Discount rate - Successor	**4.88 %**	5.31 %		**4.62 %**	4.96 %	
Discount rate - Predecessor		4.88 %	5.75 %		4.62 %	5.35 %
Expected rate of return on plan assets - Successor	**7.00 %**	8.00 %		**6.00 %**	6.00 %	
Expected rate of return on plan assets - Predecessor		7.00 %	8.50 %		6.00 %	6.00 %
Rate of compensation increases	**3.94 %**	3.94 %	4.44 %	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2012, 2011 and 2010 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2012	2011	2010	**2012**	2011	201(
Pre - age 65						
Current health care cost trend rate	**8.50 %**	8.50 %	9.50 %	**8.00 %**	8.50 %	8.5C %
Year trend reaches ultimate - Successor	**2019**	2018		**2019**	2019	
Year trend reaches ultimate - Predecessor		2019	2015		2019	201ξ
Post - age 65						
Current health care cost trend rate	**8.00 %**	8.00 %	9.00 %	**7.50 %**	8.00 %	8.0C %
Year trend reaches ultimate - Successor	**2018**	2017		**2018**	2018	
Year trend reaches ultimate - Predecessor		2018	2014		2018	201ī
Ultimate health care cost trend rate	**5.00 %**	5.00 %	5.00 %	**5.00 %**	5.00 %	5.0C %

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-percen decrease
Service cost plus interest cost	0.1	(0.1
Benefit obligation	1.2	(1.0

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	Postretirem ent
2013	22.1	2.5
2014	22.5	2.4

2015	23.0	2.3
2016	23.3	2.1
2017	23.7	1.9
2018-2022	122.6	7.6

We expect to make contributions of $0.4 million to our SERP in 2013 to cover benefit payments. We also expect to contribute $2.1 million to our other postretirement benefit plans in 2013 to cover benefit payments.

The Pension Protection Act of 2006 (the Act) 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 2012 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 116.56% and is estimated to be 116.56% until the 2013 status is certified in September 2013 for the 2013 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.

The fair values of our pension plan assets at December 31, 2012 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2012

Asset Category $ in millions	**Market Value at December 31, 2012**	**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	14.3	-	14.3	-
Large cap equity	50.5	-	50.5	-
International equity	37.0	-	37.0	-
Total equity securities	101.8	-	101.8	-
Debt securities [(b)]				
Emerging markets debt	7.4	-	7.4	-
High yield bond	12.7	-	12.7	-
Long duration fund	188.6	-	188.6	-
Total debt securities	208.7	-	208.7	-
Cash and cash equivalents [(c)]				
Cash	13.9	13.9	-	-
Other investments [(d)]				
Limited partnership interest	-	-	-	-
Common collective fund	37.0	-	-	37.0
Total other investments	37.0	-	-	37.0
Total pension plan assets	361.4	13.9	310.5	37.0

(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.

(b) This category includes investments in investment-grade fixed-income instruments that are designed to mirror the term of the pension assets and generally have a tenor between 10 and 30 years. 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 and the proceeds received from the sale of the DPL common stock, which was cashed-out at $30/share at the Merger date. 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 of the fund 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.

The fair values of our pension plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011

Asset Category $ in millions	Market Value at December 31, 2011	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	16.2	-	16.2	-
Large cap equity	54.5	-	54.5	-
International equity	34.2	-	34.2	-
Total equity securities	104.9	-	104.9	-
Debt securities [b]				
Emerging markets debt	-	-	-	-
Fixed income	-	-	-	-
High yield bond	-	-	-	-
Long duration fund	130.8	-	130.8	-
Total debt securities	130.8	-	130.8	-
Cash and cash equivalents [c]				
Cash	28.0	28.0	-	-
Other investments [d]				
Limited partnership interest	0.8	-	-	0.8
Common collective fund	71.4	-	-	71.4
Total other investments	72.2	-	-	72.2
Total pension plan assets	335.9	28.0	235.7	72.2

(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 funds.

(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 of the fund 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.

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

Change in fair value measurements of pension assets using significant unobservable inputs (Level 3)

$ in millions	Limited Partnership Interest	Common Collective Fund
January 1, 2011 through November 27, 2011 (Predecessor):		
Beginning balance January 1, 2011	2.8	57.4
Actual return on plan assets:		
Relating to assets still held at the reporting date	(0.8)	(1.5
Relating to assets sold during the period	-	-
Purchases, sales and settlements	(1.1)	15.4
Transfers in and / or out of Level 3	-	-
Ending balance at November 27, 2011	0.9	71.3
November 28, 2011 through December 31, 2011 (Successor):		
Beginning balance November 28, 2011	0.9	71.3
Actual return on plan assets:		
Relating to assets still held at the reporting date	-	0.1
Relating to assets sold during the period	-	-
Purchases, sales and settlements	(0.1)	-
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2011	0.8	71.4
Year ended December 31, 2012		
Actual return on plan assets:		
Relating to assets still held at the reporting date	**-**	**1.4**
Relating to assets sold during the period	**0.9**	**-**
Purchases, sales and settlements	**(1.7)**	**(35.8**
Transfers in and / or out of Level 3	**-**	**-**
Ending balance at December 31, 2012	**(0.0)**	**37.0**

The fair values of our other postretirement benefit plan assets at December 31, 2012 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2012

Asset Category $ in millions	**Market Value at December 31, 2012**	**Quoted prices in active markets for identical assets**	**Significa nt observable inputs**	**Significa nt unobservabl inputs**
		(Level 1)	(Level 2)	(Level 3)
JP Morgan Core Bond Fund [a]	4.2	-	4.2	-

(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, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011

Asset Category $ in millions	**Market Value at December 31, 2011**	**Quoted prices in active markets for identical assets**	**Significa nt observable inputs**	**Significa nt unobservabl inputs**
		(Level 1)	(Level 2)	(Level 3)
JP Morgan Core Bond Fund [a]	4.5	-	4.5	-

(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.

10. 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, 2012 and 2011. See also Note 11 for the fair values of our derivative instruments.

	December 31, 2012		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	**4.0**	**5.1**	3.9	4.4
Debt securities	**4.6**	**5.0**	5.0	5.5
Multi-strategy fund	**0.3**	**0.3**	0.3	0.2
Total assets	**9.1**	**10.6**	9.4	10.3
Liabilities				
Debt	**2,609.9**	**2,707.1**	2,629.3	2,710.6

Debt

The carrying value of **DPL's** debt was adjusted to fair value at the Merger date. The fair value of the debt at December 31, 2012 did not change substantially from the value at the Merger date. Unrealized gains or losses

are not recognized in the financial statements as debt is presented at the carrying value established at the Merger date, net of unamortized premium or discount 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. 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.

DPL had $0.7 million ($0.5 million after tax) and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2012 and $0.9 million ($0.6 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2011.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. $0.1 million ($0.1 million after tax) of unrealized gains were reversed into earnings during the past twelve months. $0.1 million ($0.1 million after tax) of unrealized gains are expected to be reversed to earnings over 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, 2012 and 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 December 31, 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

$ in millions	**Fair Value at December 31, 2012**	**Unfunded Commitments**	**Redemptio n Frequency**
Money market fund [a]	**0.2**	-	Immediate
Equity securities [b]	**5.1**	-	Immediate
Debt Securities [c]	**5.0**	-	Immediate
Multi-strategy fund [d]	**0.3**	-	Immediate
Total	**10.6**	-	

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	Fair Value at December 31, 2011	Unfunded Commitments	Redemptior Frequency
Money market fund [a]	0.2	-	Immediate
Equity securities [b]	4.4	-	Immediate
Debt Securities [c]	5.5	-	Immediate
Multi-strategy fund [d]	0.2	-	Immediate
Total	10.3	-	

(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 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 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, 2012 and 2011.

The fair value of assets and liabilities at December 31, 2012 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

$ in millions	Fair Value at December 31, 2012(a)	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other observable inputs	Level 3 Unobsen able inputs
Assets				
Master trust assets				
Money market funds	0.2	0.2	-	-
Equity securities	5.1	-	5.1	-
Debt securities	5.0	-	5.0	-
Multi-strategy fund	0.3	-	0.3	-
Total Master trust assets	10.6	0.2	10.4	-
Derivative assets				
Heating oil futures	0.2	0.2	-	-
Forward power contracts	6.3	-	6.3	-
Total derivative assets	6.5	0.2	6.3	-
Total assets	17.1	0.4	16.7	-
Liabilities				
Derivative liabilities				
FTRs	(0.1)	-	-	(0.1
Interest rate hedges	(29.5)	-	(29.5)	-
Forward power contracts	(13.1)	-	(13.1)	-
Total derivative liabilities	(42.7)	-	(42.6)	(0.1

Long Term Debt	(2,707.1)	-	(2,688.2)	(18.9
Total liabilities	(2,749.8)	-	(2,730.8)	(19.0

(a) Includes credit valuation adjustment.

As of December 31, 2012, this table includes Forward power contracts in an asset position of $6.3 million. This table does not include $8.2 million of Forward power contracts that had been, but no longer need to be, accounted for as derivatives at fair value that are to be amortized to earnings over the remaining term of the associated forward contract. The amortization is discussed in Note 11.

The fair value of assets and liabilities at 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

$ in millions	Fair Value at December 31, 2011(a)	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	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 hedges	(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)	-

(a) Includes credit valuation adjustment.

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 note 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 98% 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. A new ARO liability in the amount of $0.1 million was established in 2012 associated with a gypsum landfill disposal site that is presently under construction. This increase in 2012 was offset by a $0.1 million reduction in ARO for asbestos as a result of an acceleration of removal and remediation activities. There were $4.8 million of gross additions to our existing river structures and asbestos AROs as a result of the purchase accounting adjustments in 2011. There were additions of $0.1 million and $0.9 million during the periods November 28, 2011 through December 31, 2011January 1, 2011 through November 27, 2011, respectively.

Cash Equivalents

DPL had $130.0 million and $125.0 million in money market funds classified as cash and cash equivalents in its Consolidated Balance Sheets at December

31, 2012 and 2011, respectively. The money market funds have quoted prices that are generally equivalent to par.

11. 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 December 31, 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	6.9	-	6.9
Heating Oil Futures	Mark to Market	Gallons	1,764.0	-	1,764.0
Forward Power Contracts	Cash Flow Hedge	MWh	1,021.0	(2,197.9)	(1,176.9
Forward Power Contracts	Mark to Market	MWh	2,510.7	(4,760.4)	(2,249.7
Interest Rate Swaps	Cash Flow Hedge	USD	160,000.0	-	160,000.0

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 [(a)]	Mark to Market	Tons	2,015.0	-	2,015.0
Interest Rate Swaps	Cash Flow Hedge	USD	160,000.0	-	160,000.0

(a) Includes our partners' share for the jointly-owned stations 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 values of cash flow hedges 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 and our sale of retail power to third parties through our subsidiary DPLER. 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. See Note 7 for further information. 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:

	Successor				**Predecessor**			
	Year ended December 31, 2012		November 28, 2011 through December 31, 2011		January 1, 2011 through November 27, 2011		Year ended December 31, 201(	
$ in millions	**Power**	**Interest Rate Hedges**	Power	Interest Rate Hedges	Power	Interest Rate Hedges	Power	Interest Rate Hedges
Beginning accumulated derivative gain / (loss) in AOCI [(a)]	**0.3**	**(0.8)**	-	-	(1.8)	21.4	(1.4)	14.7
Net gains / (losses) associated with current period hedging transactions	**(2.6)**	**1.1**	0.1	(0.6)	(1.2)	(57.0)	3.1	9.2
Net gains reclassified to earnings:								
Interest Expense	**-**	**0.2**	-	(0.2)	-	(2.3)	-	(2.5
Revenues	**(0.7)**	**-**	0.1	-	1.1	-	(3.5)	-
Purchased Power	**-**	**-**	0.1	-	0.9	-	-	-
Ending accumulated derivative gain / (loss) in AOCI	**(3.0)**	**0.5**	0.3	(0.8)	(1.0)	(37.9)	(1.8)	21.4
Net gains / (losses) associated with the ineffective portion of the hedging transaction								
Interest Expense	**-**	**0.2**	-	0.4	-	5.1	-	-
Revenues	**-**	**-**	-	-	-	-	-	-
Portion expected to be reclassified to earnings in the next twelve months [(b)]	**(7.7)**	**-**	-	-	-	-	-	-
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**24.0**	**8.0**						

(a) Approximately $38.9 million of unrealized losses previously deferred into AOCI were removed as a result of purchase accounting. See Note 2 for further details of the purchase price allocation.

(b) 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 shows the fair value and balance sheet classification of **DPL's** derivative instruments designated as hedging instruments at December 31, 2012 and 2011.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2012

$ in millions	Fair Value [a]	Balance Sheet Location
Short-term Derivative Positions		
Forward Power Contracts in an Asset Position	**0.5**	Other prepayments and current assets
Forward Power Contracts in a Liability Position	**(6.7)**	Other current liabilities
Interest Rate Hedges in a Liability Position	**(29.5)**	Other current liabilities
Total Short-term Cash Flow Hedges	**(35.7)**	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	**0.5**	Other deferred assets
Forward Power Contracts in a Liability Position	**(1.5)**	Other deferred credits
Interest Rate Hedges in a Liability Position	**-**	Other deferred credits
Total Long-term Cash Flow Hedges	**(1.0)**	
Total Cash Flow Hedges	**(36.7)**	

(a) Includes credit valuation adjustment.

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

$ in millions	Fair Value [a]	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)

(a) Includes credit valuation adjustment.

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 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 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** derivatives not designated as hedging instruments for the year ended December 31, 2012, the period November 28, 2011 through December 31, 2011, the period January 1, 2011 through November 27, 2011, and the year ended December 31, 2010.

	Successor
	Year ended December 31, 2012

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	**14.5**	**(1.6)**	**(0.2)**	**4.3**	**17.0**
Realized gain / (loss)	**(29.5)**	**1.9**	**0.5**	**(5.0)**	**(32.1**
Total	**(15.0)**	**0.3**	**0.3**	**(0.7)**	**(15.1**
Recorded on Balance Sheet:					
Partners' share of gain	**4.2**	**-**	**-**	**-**	**4.2**
Regulatory (asset) / liability	**1.0**	**(0.6)**	**-**	**-**	**0.4**
Recorded in Income Statement: gain / (loss)					
Revenue	**-**	**-**	**-**	**(5.1)**	**(5.1**
Purchased Power	**-**	**-**	**0.3**	**4.4**	**4.7**
Fuel	**(20.2)**	**0.7**	**-**	**-**	**(19.5**
O&M	**-**	**0.2**	**-**	**-**	**0.2**
Total	**(15.0)**	**0.3**	**0.3**	**(0.7)**	**(15.1**

November 28, 2011 through December 31, 2011

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized loss	(1.4)	(0.5)	-	(0.8)	(2.7
Realized gain / (loss)	(1.2)	0.1	0.1	(0.9)	(1.9
Total	(2.6)	(0.4)	0.1	(1.7)	(4.6
Recorded on Balance Sheet:					
Partners' share of loss	(0.3)	-	-	-	(0.3
Regulatory asset	(0.1)	(0.1)	-	-	(0.2
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	0.6	0.6
Purchased Power	-	-	0.1	(2.3)	(2.2
Fuel	(2.2)	(0.3)	-	-	(2.5
O&M	-	-	-	-	-
Total	(2.6)	(0.4)	0.1	(1.7)	(4.6

Predecessor

January 1, 2011 through November 27, 2011

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total

Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	(50.7)	0.6	(0.2)	0.8	(49.5
Realized gain / (loss)	8.7	2.2	(0.6)	(2.7)	7.6
Total	(42.0)	2.8	(0.8)	(1.9)	(41.9
Recorded on Balance Sheet:					
Partners' share of loss	(25.9)	-	-	-	(25.9
Regulatory (asset) / liability	(7.0)	0.1	-	-	(6.9
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(3.8)	(3.8
Purchased Power	-	-	(0.8)	1.9	1.1
Fuel	(9.1)	2.5	-	-	(6.6
O&M	-	0.2	-	-	0.2
Total	(42.0)	2.8	(0.8)	(1.9)	(41.9

	Year ended December 31, 2010				
$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
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	20.1	-	-	-	20.1
Regulatory 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

The following tables show the fair value and balance sheet classification of **DPL's** derivative instruments not designated as hedging instruments at December 31, 2012 and 2011.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
December 31, 2012

$ in millions	Fair Value [(a)]	Balance Sheet Location

Short-term Derivative Positions		
FTRs in a Liability Position	**(0.1)**	Other current liabilities
Forward Power Contracts in an Asset Position	**2.7**	Other prepayments and current assets
Forward Power Contracts in a Liability Position	**(4.1)**	Other current liabilities
Heating Oil Futures in an Asset Position	**0.2**	Other prepayments and current assets
Total Short-term Derivative MTM Positions	**(1.3)**	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	**3.6**	Other deferred assets
Forward Power Contracts in a Liability Position	**(0.8)**	Other deferred credits
Total Long-term Derivative MTM Positions	**2.8**	
Net MTM Position	**1.5**	

(a) Includes credit valuation adjustment.

As of December 31, 2012, this table includes Forward power contracts in a short-term asset position of $2.7 million and a long-term asset position of $3.6 million. This table does not include a short-term asset position of $7.2 million or a long-term asset position of $1.0 million of Forward power contracts that had been, but no longer need to be, accounted for as derivatives at fair value that are to be amortized to earnings over the remaining term of the associated forward contract. The amortization is included in the above table for the Year Ended December 31, 2012.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
December 31, 2011

$ in millions	Fair Value [(a)]	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	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)

(a) Includes credit valuation adjustment.

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. Since our debt

has fallen below investment grade, some of our counterparties to the derivative instruments have requested collateralization of the MTM loss.

The aggregate fair value of **DPL's** derivative instruments that are in a MTM loss position at December 31, 2012 is $13.2 million. This amount is offset by $5.1 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 $6.3 million. Since our debt is below investment grade, we could have to post collateral for the remaining $1.8 million.

12. Share-based Compensation

In April 2006, **DPL's** shareholders approved The DPL Inc. Equity and Performance Incentive Plan (the EPIP) which became immediately effective for a term of ten years. The Compensation Committee of the Board of Directors designated the employees and directors eligible to participate in the EPIP and the times and types of awards to be granted. A total of 4,500,000 shares of **DPL** common stock had been reserved for issuance under the EPIP.

As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date. The remaining compensation expense of $5.5 million ($3.6 million after tax) was expensed as of the Merger date.

The following table summarizes share-based compensation expense (note that there is no share-based compensation activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Performance shares	2.4	2.1
Restricted shares	5.3	1.7
Non-employee directors' RSUs	0.6	0.4
Management performance shares	1.8	0.5
Share-based compensation included in Operation and	10.1	4.7

maintenance expense		
Income tax benefit	(3.5)	(1.6
Total share-based compensation, net of tax	6.6	3.1

Share-based awards issued in **DPL's** common stock were distributed from treasury stock prior to the Merger; as of the Merger date, remaining share-based awards were distributed in cash in accordance with the Merger agreement.

Determining Fair Value

Valuation and Amortization Method – We estimated the fair value of performance shares using a Monte Carlo simulation; restricted shares were valued at the closing market price on the day of grant and the Directors' RSUs were valued at the closing market price on the day prior to the grant date. We amortized the fair value of all awards on a straight-line basis over the requisite service periods, which were generally the vesting periods.

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

Expected Life – The expected life assumption represented the estimated period of time from the grant date until the exercise date and reflected historical employee exercise patterns.

Risk-Free Interest Rate – The risk-free interest rate for the expected term of the award was 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 was used for valuing an award with a five year expected life.

Expected Dividend Yield – The expected dividend yield was 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 was based on **DPL's** historical experience, adjusted as necessary to reflect special circumstances.

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 were granted under The DPL Inc. Stock Option Plan. Prior to the Merger, all outstanding stock options had been exercised or had expired.

Summarized stock option activity was as follows (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

Predecessor

$ in millions	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Options:		
Outstanding at beginning of period	351,500	417,50C
Granted	-	-
Exercised	(75,500)	(66,000
Expired	(276,000)	-
Forfeited	-	-
Outstanding at end of period	-	351,50C
Exercisable at end of period	-	351,50C
Weighted average option prices per share:		
Outstanding at beginning of period	28.04	27.1E
Granted	-	-
Exercised	21.02	21.0C
Expired	29.42	-
Forfeited	-	-
Outstanding at end of period	-	28.04
Exercisable at end of period	-	28.04

The following table reflects information about stock option activity during the period (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Weighted-average grant date fair value of options granted during the period	-	-
Intrinsic value of options exercised during the period	0.7	0.5
Proceeds from options exercised during the period	1.6	1.4
Excess tax benefit from proceeds of options exercised	0.2	0.1
Fair value of options that vested during the period	-	-
Unrecognized compensation expense	-	-
Weighted-average period to recognize compensation expense (in years)	-	-

Restricted Stock Units (RSUs)

RSUs were granted to certain key employees prior to 2001. As of the Merger date, there were no RSUs outstanding.

Summarized RSU activity was as follows (note that there is no RSU activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
RSUs:		
Outstanding at beginning of period	-	3,311
Granted	-	-
Dividends	-	-
Exercised	-	(3,311
Forfeited	-	-
Outstanding at end of period	-	-
Exercisable at end of period	-	-

Performance Shares

Under the EPIP, the Board of Directors adopted a Long-Term Incentive Plan (LTIP) under which **DPL** granted a targeted number of performance shares of common stock to executives. Grants under the LTIP were awarded based on a Total Shareholder Return Relative to Peers performance. The Total Shareholder Return Relative to Peers is considered a market condition in accordance with the accounting guidance for share-based compensation.

At the Merger date, vesting for all non-vested LTIP performance shares was accelerated on a pro rata basis and such shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized performance share activity was as follows (note that there is no performance share activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Performance shares:		
Outstanding at beginning of period	278,334	237,704
Granted	85,093	161,534
Dividends	(198,699)	(91,253
Exercised	(66,836)	-
Forfeited	(97,892)	(29,651
Outstanding at end of period	-	278,334
Exercisable at end of period	-	66,836

The following table reflects information about performance share activity during the period (note that there is no performance share activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Weighted-average grant date fair value of performance shares granted during the period	2.2	2.9
Intrinsic value of performance shares exercised during the period	6.0	2.5
Proceeds from performance shares exercised during the period	-	-
Excess tax benefit from proceeds of performance shares exercised	0.7	-
Fair value of performance shares that vested during the period	4.7	1.6
Unrecognized compensation expense	-	2.4
Weighted-average period to recognize compensation expense (in years)	-	1.7

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:

	Predecessor	
	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Expected volatility	24.0%	24.3%
Weighted-average expected volatility	24.0%	24.3%
Expected life (years)	3.0	3.0
Expected dividends	5.0%	4.5%
Weighted-average expected dividends	5.0%	4.5%
Risk-free interest rate	1.2%	1.4%

Restricted Shares

Under the EPIP, the Board of Directors granted shares of **DPL** Restricted Shares to various executives and other key employees. These Restricted Shares were registered in the recipient's name, carried full voting privileges, received dividends as declared and paid on all **DPL** common stock and vested after a specified service period.

In July 2008, the Board of Directors granted Restricted Share awards under the EPIP to a select group of management employees. The management Restricted Share awards had a three-year requisite service period, carried full voting privileges and received 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 was a Restricted Share grant and the second part was a matching

Restricted Share grant. These Restricted Share grants generally vested after five years if the participant remained continuously employed with **DPL** or a **DPL** subsidiary and if the year-over-year average EPS had increased by at least 1% from 2009 to 2013. Under the matching Restricted Share grant, participants had a three-year period from the date of plan implementation during which they could purchase **DPL** common stock equal in value to up to two times their 2009 base salary. **DPL** matched the shares purchased with another grant of Restricted Shares (matching Restricted Share grant). The percentage match by **DPL** is detailed in the table below. The matching Restricted Share grant would have generally vested over a three-year period if the participant continued to hold the originally purchased shares and remained continuously employed with **DPL** or a **DPL** subsidiary. The Restricted Shares were registered in the recipient's name, carried full voting privileges and received dividends as declared and paid on all **DPL** common stock.

The matching criteria were:

Value (Cost Basis) of Shared Purchased as a % of 2009 Base Salary	Company % Match of Value of Shares Purchased
1% to 25%	25%
>25% to 50%	50%
>50% to 100%	75%
>100% to 200%	125%

The matching percentage was applied on a cumulative basis and the resulting Restricted Share grant was adjusted at the end of each calendar quarter. As a result of the Merger, the matching Restricted Share grants were suspended in March 2011.

In February 2011, the Board of Directors granted a targeted number of time-vested Restricted Shares to executives under the LTIP. These Restricted Shares did not carry voting privileges nor did they receive dividend rights during the vesting period. In addition, a one-year holding period was implemented after the three-year vesting period was completed.

Restricted Shares could only be awarded in **DPL** common stock.

At the Merger date, vesting for all non-vested Restricted Shares was accelerated and all outstanding shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized Restricted Share activity was as follows (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1,	Year endec

	2011 through November 27, 2011	December 31, 2010
Restricted shares:		
Outstanding at beginning of period	219,391	218,197
Granted	67,346	42,977
Exercised	(286,737)	(20,803
Forfeited	-	(20,980
Outstanding at end of period	-	219,391
Exercisable at end of period	-	-

The following table reflects information about Restricted Share activity during the period (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Weighted-average grant date fair value of restricted shares granted during the period	1.8	1.1
Intrinsic value of restricted shares exercised during the period	8.6	0.4
Proceeds from restricted shares exercised during the period	-	-
Excess tax benefit from proceeds of restricted shares exercised	0.5	0.1
Fair value of restricted shares that vested during the period	7.5	0.6
Unrecognized compensation expense	-	3.4
Weighted-average period to recognize compensation expense (in years)	-	2.7

Non-Employee Director RSUs

Under the EPIP, as part of their annual compensation for service to **DPL** and **DP&L**, each non-employee Director received a retainer in RSUs on the date of the shareholders' annual meeting. The RSUs became non-forfeitable on April 15 of the following year. The RSUs accrued quarterly dividends in the form of additional RSUs. Upon vesting, the RSUs became exercisable and were distributed in **DPL** common stock, unless the Director chose to defer receipt of the shares until a later date. The RSUs were valued at the closing stock price on the day prior to the grant and the compensation expense was recognized evenly over the vesting period.

At the Merger date, vesting for the remaining non-vested RSUs was accelerated and all vested RSUs (current and prior years) were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

The following table reflects information about RSU activity (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

$ in millions	Predecessor: January 1, 2011 through November 27, 2011	Predecessor: Year endec December 31, 2010
Restricted stock units:		
Outstanding at beginning of period	16,320	20,712
Granted	14,392	15,752
Dividends accrued	3,307	2,484
Vested and exercised	(34,019)	(2,618
Vested, exercised and deferred	-	(20,010
Forfeited	-	-
Outstanding at end of period	-	16,32C
Exercisable at end of period	-	-

The following table reflects information about non-employee Director RSU activity during the period (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

$ in millions	Predecessor: January 1, 2011 through November 27, 2011	Predecessor: Year endec December 31, 2010
Weighted-average grant date fair value of non-employee Director RSUs granted during the period	0.5	0.5
Intrinsic value of non-employee Director RSUs exercised during the period	1.0	0.5
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	1.0	0.6
Unrecognized compensation expense	-	0.1
Weighted-average period to recognize compensation expense (in years)	-	0.3

Management Performance Shares

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

At the Merger date, vesting for all non-vested management performance shares was accelerated; some of the awards vested at target shares and other awards vested at a pro rata share of target. All vested shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized management performance share activity was as follows (note that there is no management performance share activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Management performance shares:		
Outstanding at beginning of period	104,124	84,241
Granted	49,510	37,48C
Expired	(31,081)	-
Exercised	(111,289)	-
Forfeited	(11,264)	(17,597
Outstanding at end of period	-	104,124
Exercisable at end of period	-	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:

	Predecessor	
	January 1, 2011 through November 27, 2011	Year endec December 31, 2010
Expected volatility	24.0%	24.3%
Weighted-average expected volatility	24.0%	24.3%
Expected life (years)	3.0	3.0
Expected dividends	5.0%	4.5%
Weighted-average expected dividends	5.0%	4.5%
Risk-free interest rate	1.2%	1.4%

The following table reflects information about management performance share activity during the period (note that there is no management performance share activity after November 27, 2011 as a result of the Merger):

	Predecessor	
$ in millions	January 1, 2011 through November 27,	Year endec December 31, 2010

	2011	
Weighted-average grant date fair value of management performance shares granted during the period	1.3	0.9
Intrinsic value of management performance shares exercised during the period	3.3	-
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	2.7	0.9
Unrecognized compensation expense	-	0.9
Weighted-average period to recognize compensation expense (in years)	-	1.7

13. Redeemable Preferred Stock

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,058 were outstanding as of December 31, 2012. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2012. The table below details the preferred shares outstanding at December 31, 2012:

		December 31, 2012 and 2011		Carrying Value [a] ($ in millions)	
	Preferred Stock Rate	Redemption price ($ per share)	Shares Outstanding	December 31, 2012	December 31, 2011
DP&L Series A	3.75%	102.50	93,280	7.4	7.4
DP&L Series B	3.75%	103.00	69,398	5.6	5.6
DP&L Series C	3.90%	101.00	65,380	5.4	5.4
Total			228,058	18.4	18.4

(a) Carrying value is fair value at Merger date.

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 affected **DP&L's** ability to pay cash dividends and, as of December 31, 2012, **DP&L's** retained earnings of $534.2 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.

14. Common Shareholders' 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 December 31, 2012.

On October 27, 2010, the **DPL** Board of Directors approved a new Stock Repurchase Program that permitted **DPL** to 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 was scheduled to run through December 31, 2013, but was suspended in connection with the Merger, discussed further in Note 2.

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, discussed further 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 is 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 previously 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.

Rights Agreement

DPL's Rights Agreement, dated as of September 25, 2001, with Computershare Trust Company, N.A. (the "Rights Agreement") expired in December 2011. The Rights Agreement attached one right to each common share outstanding at the close of business on December 31, 2001. The rights were separate from the common shares and had been exercisable at the exercise price of $130 per right in the event of certain attempted business combinations.

The Rights Agreement was amended as of April 19, 2011, to provide that neither the execution of the Merger agreement nor the consummation of the transactions contemplated by the Merger agreement would trigger the provisions of the Rights Agreement.

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. ESOP shares used to fund matching contributions to **DP&L's** 401(k) vested after either two or three years of service in accordance with the match formula effective for the respective plan match year; other compensation shares awarded vested immediately. In 1992, the ESOP Plan entered into a $90 million loan agreement with **DPL** in order to purchase shares of **DPL** common stock in the open market. The leveraged ESOP was funded by an exempt loan, which was secured by the ESOP shares. As debt service payments were made on the loan, shares were released on a pro rata basis. 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 were used to repay the principal and interest on the ESOP loan to **DPL**. Dividends on the allocated shares were charged to retained earnings and the share value of these dividends was allocated to participants.

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 million on the loan with **DPL** using the merger proceeds from **DPL** common stock held within the ESOP suspense account.

Compensation expense recorded, based on the fair value of the shares committed to be released, amounted to zero from November 28, 2011 through December 31, 2011 and forward (successor), $4.8 million from January 1, 2011 through November 27, 2011 (predecessor) and $6.7 million in 2010.

For purposes of EPS computations and in accordance with GAAP, we treated ESOP shares as outstanding if they were allocated to participants, released or had been committed to be released. ESOP cumulative shares outstanding for the calculation of EPS were 4.6 million in 2010 and 4.2 million in 2009.

15. 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 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 the period January 1, 2011, through November 27, 2011 and the year ended December 31, 2010. Effective with the Merger, **DPL** is an indirectly wholly-owned subsidiary of AES and earnings per share information is no longer required.

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

	January 1, 2011 through November 27, 2011			Year ended December 31, 201		
$ and shares in millions except per share amounts	Income	Shares	Per Share	Income	Shares	Per Share
Basic EPS	150.5	114.5	$ 1.31	290.3	115.6	2.51
Effect of Dilutive Securities:						
Warrants		0.4			0.3	
Stock options, performance and restricted shares		0.2			0.2	
Diluted EPS	150.5	115.1	$ 1.31	290.3	116.1	2.5

16. 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.

17. 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 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 December 31, 2012, **DPL** had $21.5 million of guarantees to third parties for future financial or performance assurance under such agreements, including $21.2 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 Consolidated Balance Sheets was $0.0 million and $0.1 million at December 31, 2012 and 2011, respectively.

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 December 31, 2012, **DP&L** could be responsible for the repayment of 4.9%, or $78.2 million, of a $1,596.5 million debt obligation comprised of both fixed and variable rate securities with maturities between 2013 and 2040. This would only happen if this electric generation company defaulted on its debt payments. At December 31, 2012, 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, 2012, these include:

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DPL:					
Long-term debt	2,598.7	570.4	425.3	450.2	1,152.8
Interest payments	1,031.4	133.5	216.3	174.1	507.5

Pension and postretirement payments	256.2	24.6	50.3	51.1	130.2
Operating leases	1.0	0.4	0.6	-	-
Coal contracts [(a)]	586.4	227.6	150.6	138.8	69.4
Limestone contracts [(a)]	26.8	5.4	10.7	10.7	-
Purchase orders and other contractual obligations	55.9	34.6	10.9	10.4	-
Reserve for uncertain tax positions	18.3	18.3	-	-	-
Total contractual obligations	4,574.7	1,014.8	864.7	835.3	1,859.9

(a) Total at DP&L operated units.

Long-term debt:

DPL's long-term debt as of December 31, 2012, consists 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 WPAFB note. These long-term debt amounts include current maturities but exclude unamortized debt discounts, premiums and fair value adjustments.

DP&L's long-term debt as of December 31, 2012, consists of first mortgage bonds, tax-exempt pollution control bonds, capital leases, and the WPAFB note. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 7 for additional information.

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, 2012.

Pension and postretirement payments:

As of December 31, 2012, **DPL**, through its principal subsidiary **DP&L**, had estimated future benefit payments as outlined in Note 9. These estimated future benefit payments are projected through 2022.

Capital leases:

As of December 31, 2012, **DPL**, through its principal subsidiary **DP&L**, had two immaterial capital leases that expire in 2013 and 2014.

Operating leases:

As of December 31, 2012, **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 stations 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, 2012, **DPL** 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:

As of December 31, 2012, **DPL** had $18.3 million in uncertain tax positions which are expected to be resolved within the next year.

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, 2012, 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 estimated liabilities of approximately $3.6 million for environmental matters. We evaluate the potential liability related to probable losses arising from environmental matters 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 electric generating stations. Some of these matters could have material adverse impacts on the operation of the stations; especially the stations that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired generating units 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 commonly owned Unit 6, in December 2014. This was followed by a notification by the joint owners of Beckjord 6 to PJM, dated April 12, 2012, of a planned June 1, 2015 deactivation of this unit. Beckjord was valued at zero at the Merger date. We do not believe that any additional accruals are needed as a result of this decision.

DP&L has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated June 1, 2014. In addition, **DP&L** has notified PJM that the remaining Hutchings units 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 how much of a pollutant 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 electric generating stations 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 stations. Once fully implemented in 2014, the rule would have required 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, we believe companies will have three years or more before they 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. On January 24, 2013, the D.C. Circuit Court denied this petition for rehearing en banc of the D.C. Circuit Court's August 2012 decision to vacate CSAPR. Therefore, CAIR remains in effect. If CSAPR were to be reinstated in its current form, we do not expect any material capital costs for **DP&L's** stations, 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 replacement interstate transport 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. Our 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 could have a material adverse effect on our results of operations and result in material compliance costs.

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. On December 21, 2012, the Administrator of USEPA signed the final rule, which will be followed by publication in the Federal Register. Compliance costs are not expected to be material to **DP&L's** operations.

On May 3, 2010, the National Emissions Standards for Hazardous Air Pollutants for compression ignition (CI) reciprocating internal combustion engines (RICE) became effective. 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. **DP&L**

expects to meet this deadline and expects the compliance costs to be immaterial.

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 December 31, 2012, USEPA redesignated Adams County, where Stuart and Killen are located, to attainment status. This status may be

temporary, as on December 12, 2012, the USEPA tightened the PM 2.5 standard to 12.0 micrograms per cubic meter. This will begin a process of redesignations during 2014. We cannot predict the effect the revisions to the PM 2.5 standard will have on **DP&L's** financial condition or results of operations.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. On September 2, 2011, the USEPA decided to postpone their revisiting of this standard until 2013. **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.

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. Numerous units owned and operated by us will be affected by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

Carbon Dioxide 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 electric generating stations. We cannot predict the effect of these standards, if any, on **DP&L's** operations.

Approximately 97% 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**.

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

Litigation Involving Co-Owned Stations

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 stations 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 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 Stations

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 Ohio Power (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 stations.

In June 2000, the USEPA issued an NOV to the **DP&L**-operated Stuart generating station (co-owned by **DP&L**, Duke Energy and Ohio Power) for alleged violations of the CAA. The NOV contained allegations 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 Stations

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 Justice Department 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 required 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, which were published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. In July 2012, USEPA announced that the final rules will be released in June 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. The 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. In November 2012, Ohio EPA issued another draft which included a compliance schedule for performing a study to justify an alternate thermal limitation and to which **DP&L** submitted comments. In December 2012, the USEPA formally withdrew their objection to the permit. On January 7, 2013, Ohio EPA issued a final permit. On February 1, 2013, **DP&L** appealed various aspects of the final permit to the Environmental Review Appeals Commission. 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. Subsequent to the information collection effort, it was anticipated that the USEPA would release a proposed rule by mid-2012 with a final regulation in place by early 2014. In December 2012, USEPA announced that the proposed rule would be released by April 19, 2013 with a deadline for a final rule on May 22, 2014. At present, **DP&L** is unable to predict the impact this rulemaking will have on its operations.

In August 2012, **DP&L** submitted an application for the renewal of the Killen Station NPDES permit which expired in January 2013. At present, the outcome of this proceeding is not known.

In April 2012, **DP&L** received an NOV related to the construction of the Carter Hollow landfill at the 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 NOV. 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, was conducted in 2012 and may continue throughout 2013. In October 2012, **DP&L** received a request from PRP group's consultant to conduct additional soil and groundwater sampling on **DP&L's** service center property. **DP&L** is complying with this sampling request. On February 8, 2013, the Court granted **DP&L's** motion for summary judgment on statute of limitations grounds with respect to claims seeking a contribution toward the costs that are expected to be incurred by PRP group in their performing a Remediation Investigation and Feasibility Study. The Court's ruling is likely to be appealed. **DP&L** is unable to predict the outcome of the appeal. Additionally, the Court's ruling does not address future litigation that may arise with respect to actual remediation costs. 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 seeking information from potentially affected parties on how it should proceed, the outcome may have a material effect on **DP&L**. While the USEPA has indicated that the official release date for a proposed rule is sometime in April 2013, it may be delayed until late 2013 or early 2014. At present, **DP&L** is unable to predict the impact this initiative will have on its operations.

<u>Regulation of Ash Ponds</u>

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 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 May 2012, we received a draft report on the inspection. **DP&L** submitted comments on the draft report in June 2012. **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. Litigation has been filed by several groups seeking a court-ordered deadline for the issuance of a final rule which USEPA has opposed. At present, the timing for a final rule regulating coal combustion byproducts cannot be determined. **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 its operations.

Notice of Violation Involving Co-Owned Units

On September 9, 2011, **DP&L** received an NOV from the USEPA with respect to its co-owned 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 National Pollutant Discharge Elimination System 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 stations 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 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; at December 31, 2012, 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 were resolved and/or dismissed on or before March 29, 2012. Only immaterial amounts of plaintiff legal fees were paid as a result of these suits.

18. Business Segments

DPL operates through two segments consisting of the operations of two of its wholly-owned subsidiaries, **DP&L** (Utility segment) and DPLER (Competitive Retail segment) and 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 electric generating stations and is distributed to more than 513,000 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 DPLER's and MC Squared's 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 198,000 customers currently located throughout Ohio and in Illinois. In February 2011, DPLER purchased MC Squared, a Chicago-based retail electricity supplier, which served approximately 3,157 customers in Northern Illinois. Due to increased competition in Ohio and Illinois, 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. 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. **DP&L** started selling physical power to MC Squared during June 2012 and became their sole source of power in September, 2012. 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.

The following tables present financial information for each of **DPL's** reportable business segments:

Successor

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidate
Year ended December 31, 2012					
Revenues from external customers	1,138.4	493.1	36.9	-	1,668.4
Intersegment revenues	393.4	-	3.4	(396.8)	-
Total revenues	1,531.8	493.1	40.3	(396.8)	1,668.4
Fuel	354.9	-	7.0	-	361.9
Purchased power	309.5	424.5	1.5	(393.4)	342.1
Amortization of intangibles	-	-	95.1	-	95.1
Gross margin [a]	867.4	68.6	(63.3)	(3.4)	869.3

Depreciation and amortization	141.3	0.4	(16.3)	-	125.4
Goodwill impairment (Note 19)	-	-	1,817.2	-	1,817.2
Fixed asset impairment	80.8	-	(80.8)	-	-
Interest expense	39.1	0.6	83.9	(0.7)	122.9
Income tax expense / (benefit)	55.1	18.1	(25.5)	-	47.7
Net income / (loss)	91.2	22.8	(1,725.4)	(118.4)	(1,729.8
Cash capital expenditures	195.5	-	2.6	-	198.1
Total assets (end of year)	3,464.2	99.2	683.9	-	4,247.3

(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.

Successor

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
November 28, 2011 through December 31, 2011					
Revenues from external customers	116.2	38.2	2.5	-	156.9
Intersegment revenues	27.8	-	0.3	(28.1)	-
Total revenues	144.0	38.2	2.8	(28.1)	156.9
Fuel	34.5	-	1.3	-	35.8
Purchased power	31.0	33.4	-	(27.7)	36.7
Amortization of intangibles	-	-	11.6	-	11.6
Gross margin [(a)]	78.5	4.8	(10.1)	(0.4)	72.8
Depreciation and amortization	12.7	-	(1.1)	-	11.6
Interest expense	2.8	0.1	8.8	(0.2)	11.5
Income tax expense / (benefit)	5.8	1.1	(6.3)	-	0.6
Net income / (loss)	45.8	1.7	(53.7)	-	(6.2
Cash capital expenditures	30.5	-	-	-	30.5
Total assets (end of year)	3,538.3	69.9	2,528.0	-	6,136.2

(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.

Predecessor

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
January 1, 2011 through November 27, 2011					
Revenues from external customers	1,234.5	387.2	49.2	-	1,670.9
Intersegment revenues	299.2	-	3.7	(302.9)	-
Total revenues	1,533.7	387.2	52.9	(302.9)	1,670.9
Fuel	346.1	-	9.7	-	355.8
Purchased power	370.6	330.5	2.7	(299.2)	404.6
Gross margin [(a)]	817.0	56.7	40.5	(3.7)	910.5
Depreciation and amortization	122.2	0.6	6.6	-	129.4
Interest expense	35.4	0.2	23.4	(0.3)	58.7
Income tax expense / (benefit)	98.4	16.7	(13.1)	-	102.0
Net income / (loss)	147.4	24.1	(21.0)	-	150.5
Cash capital expenditures	174.0	-	0.2	-	174.2

(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.

Predecessor

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
Year ended December 31, 2010					
Revenues from external customers	1,500.3	277.0	54.1	-	1,831.4
Intersegment revenues	238.5	-	4.5	(243.0)	-
Total revenues	1,738.8	277.0	58.6	(243.0)	1,831.4
Fuel	371.9	-	12.0	-	383.9
Purchased power	383.5	238.5	3.9	(238.5)	387.4
Gross margin [(a)]	983.4	38.5	42.7	(4.5)	1,060.1
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

Cash capital expenditures	148.2	-	3.2	-	151.4
Total assets (end of year)	3,475.4	35.7	302.2	-	3,813.3

(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.

19. 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 impacted the enterprise value and the implied fair value of goodwill in the fourth quarter of 2012. 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 recognized a goodwill impairment expense of $1,850.0 million, which represented 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. In the fourth quarter of 2012, we concluded the interim impairment test of goodwill and finalized the estimation of the impairment charge. The final estimate of the goodwill impairment was $1,817.2 million. The difference between the third quarter estimate of the goodwill impairment and the finalized impairment of $1,817.2 million was recorded in the fourth quarter of 2012.

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 rate was (2.8)% for the year ended December 31, 2012.

20. Selected Quarterly Information (Unaudited)

	For the 2011 periods ended (a):				
	Predecessor				Succes sor
$ in millions except per share amounts	March 31	June 30	Septem ber 30	Novem ber 27	Decem ber 31
Revenues	480.6	433.4	497.5	259.4	N/A
Operating income	100.9	65.8	112.9	48.2	N/A
Net income	43.5	31.7	67.1	8.2	N/A
Earnings per share of common stock:					
Basic	0.38	0.28	0.58	0.07	N/A
Diluted	0.38	0.28	0.58	0.07	N/A
Dividends declared per share	0.3325	0.3325	0.3325	0.5400	N/A

	For the 2010 quarters ended:			
	Predecessor			
$ in millions except per share amounts	March 31	June 30	Septem ber 30	Decem ber 31
Revenues	437.0	434.1	502.3	458.0
Operating income	126.0	109.3	144.6	124.5
Net income	71.0	61.4	86.4	71.5
Earnings per share of common stock:				
Basic	0.61	0.53	0.75	0.62

Diluted	0.61	0.53	0.74	0.62
Dividends declared per share	0.3025	0.3025	0.3025	0.3025

(a) Periods ended March 31, June 30, and September 30 represent three months then ended. Period ended November 27 represents approximately two months then ended and period ended December 31 represents approximately one month then ended.

Effective with the Merger, **DPL** is indirectly wholly-owned by AES and quarterly information and earnings per share information are no longer required.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying balance sheet of The Dayton Power and Light Company (DP&L) as of December 31, 2012, and the related Statements of Results of Operations, Comprehensive Income / (Loss), Cash Flows and Shareholder's Equity for the year ended December 31, 2012. In connection with our audit of the financial statements, we also have audited the financial statement schedule, "Schedule II – Valuation and Qualifying Accounts" for the year ended December 31, 2012. These financial statements and schedule are the responsibility of DP&L's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit.

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

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, 2012, and the results of its operations and its cash flows for the year ended December 31, 2012, 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/ Ernst & Young
Cincinnati, Ohio
February 26, 2013

Report of Independent Registered Public Accounting Firm

The Board of Directors
Dayton Power and Light Company:

We have audited the accompanying balance sheet of The Dayton Power and Light Company (DP&L) as of December 31, 2011, and the related statements of results of operations, comprehensive income / (loss), cash flows and shareholder's equity each of the years in the two-year period ended December 31, 2011. In connection with our audits of the financial statements, we also have audited the financial statement schedule, "Schedule II – Valuation and Qualifying Accounts" for the years ended December 31, 2011 and 2010. These financial statements and schedule are the responsibility of DPL's management. Our responsibility is to express an opinion on these financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of DP&L as of December 31, 2011, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2011, 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
March 27, 2012

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF RESULTS OF OPERATIONS

$ in millions	Years ended December 31, 2012	2011	2010
Revenues	**1,531.8**	1,677.7	1,738.8
Cost of revenues:			
Fuel	**354.9**	380.6	371.9
Purchased power	**309.5**	401.6	383.5
Total cost of revenues	**664.4**	782.2	755.4
Gross margin	**867.4**	895.5	983.4
Operating expenses:			
Operation and maintenance	**385.9**	364.8	330.1
Depreciation and amortization	**141.3**	134.9	130.7
General taxes	**74.4**	75.9	72.4
Fixed asset impairment	**80.8**	-	-
Total operating expenses	**682.4**	575.6	533.2
Operating income	**185.0**	319.9	450.2
Other income / (expense), net			
Investment income	**2.3**	17.3	1.7
Interest expense	**(39.1)**	(38.2)	(37.1
Other deductions	**(1.9)**	(1.6)	(1.9
Total other expense, net	**(38.7)**	(22.5)	(37.3
Earnings (loss) from operations before income tax	**146.3**	297.4	412.9
Income tax expense	**55.1**	104.2	135.2
Net income	**91.2**	193.2	277.7
Dividends on preferred stock	**0.9**	0.9	0.9
Earnings on common stock	**90.3**	192.3	276.8

See Notes to Financial Statements.

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

$ in millions	**Year ended**	Year ended	Year ended

	December 31, 2012	December 31, 2011	December 31, 2010
Net income	**91.2**	193.2	277.7
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $(0.2), $4.3 and $0.6 for each respective period	**0.5**	(7.8)	(1.0
Reclassification to earnings, net of immaterial tax effect	**(0.1)**	-	-
Total change in fair value of available-for-sale securities	**0.4**	(7.8)	(1.0
Derivative activity:			
Change in derivative fair value, net of income tax benefit of $1.6, $0.5 and $0.2 for each respective period	**(3.0)**	(1.2)	3.1
Reclassification of earnings, net of income tax benefit / (expense) of $0.5, $0.1 and $(0.5) for each respective period	**(3.4)**	(0.2)	(5.9
Total change in fair value of derivatives	**(6.4)**	(1.4)	(2.8
Pension and postretirement activity:			
Prior Service Cost for the period, net of income tax benefit / (expense) of $(0.5), $(0.4) and $(0.4) for each respective period	**0.8**	0.5	1.2
Net loss for the period, net of income tax benefit / (expense) of $0.8, $5.4 and $(0.1) for each respective period	**(1.5)**	(8.0)	0.4
Reclassification to earnings, net of income tax benefit / (expense) of $(1.5), $(1.5) and $(0.5) for each respective period	**2.7**	2.3	1.7
Total change in unfunded pension and postretirement obligation	**2.0**	(5.2)	3.3
Other comprehensive loss	**(4.0)**	(14.4)	(0.5
Net comprehensive income	**87.2**	178.8	277.2

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF CASH FLOWS

Years ended December 31,

$ in millions	2012	2011	2010
Cash flows from operating activities:			
Net income	**91.2**	193.2	277.7
Adjustments to reconcile Net income (loss) to Net cash from operating activities			
Depreciation and amortization	**141.3**	134.9	130.7
Deferred income taxes	**3.6**	50.7	54.3
Gain on liquidation of DPL stock, held in trust	**-**	(14.6)	-
Fixed asset impairment	**80.8**	-	-
Recognition of deferred SECA revenue	**(17.8)**	-	-
Changes in certain assets and liabilities:			
Accounts receivable	**20.9**	5.3	15.2
Inventories	**14.2**	(11.8)	12.2
Prepaid taxes	**0.1**	8.1	(8.9
Taxes applicable to subsequent years	**5.2**	(9.0)	(3.6
Deferred regulatory costs, net	**(1.5)**	(12.6)	21.8
Accounts payable	**(15.3)**	7.1	16.9
Accrued taxes payable	**(8.5)**	15.2	1.7
Accrued interest payable	**5.2**	0.2	(5.4
Pension, retiree and other benefits	**28.5**	(24.0)	(58.2
Unamortized investment tax credit	**(2.5)**	(2.5)	(2.8
Other	**(5.6)**	24.0	3.7
Net cash from operating activities	**339.8**	364.2	455.3
Cash flows from investing activities:			
Capital expenditures	**(195.5)**	(204.5)	(150.0
Decrease / (increase) in restricted cash	**2.9**	(3.8)	(6.0
Purchase of emission allowances	**(0.1)**	(0.2)	(0.9
Purchase of renewable energy credits	**(5.4)**	(4.4)	(2.0
Proceeds from sale of property - other	**0.2**	-	-
Proceeds from liquidation of DPL stock, held in trust	**-**	26.9	-
Other investing activities, net	**0.4**	1.0	1.4
Net cash from investing activities	**(197.5)**	(185.0)	(157.5

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF CASH FLOWS (continued)

$ in millions	Years ended December 31, 2012	2011	2010

Cash flows from financing activities			
Dividends paid on common stock to parent	**(145.0)**	(220.0)	(300.0
Dividends paid on preferred stock	**(0.9)**	(0.9)	(0.9
Retirement of long-term debt	**(0.1)**	(0.1)	-
Cash contribution from parent	-	20.0	-
Borrowings from revolving credit facilities	-	50.0	-
Repayment of borrowings from revolving credit facilities	-	(50.0)	-
Net cash from financing activities	**(146.0)**	(201.0)	(300.9
Cash and cash equivalents:			
Net change	**(3.7)**	(21.8)	(3.1
Balance at beginning of period	**32.2**	54.0	57.1
Cash and cash equivalents at end of period	**28.5**	32.2	54.C
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	**35.1**	39.2	45.1
Income taxes (refunded) / paid, net	**61.9**	13.9	87.C
Non-cash financing and investing activities:			
Accruals for capital expenditures	**16.7**	26.5	23.2
Long-term liability incurred for the purchase of plant assets	-	18.7	-

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions	**December 31, 2012**	Decembei 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	**28.5**	32.2
Restricted funds	**10.7**	13.6
Accounts receivable, net (Note 3)	**160.0**	178.5
Inventories (Note 3)	**108.9**	123.1
Taxes applicable to subsequent years	**66.7**	71.9
Regulatory assets, current (Note 4)	**18.3**	17.7
Other prepayments and current assets	**33.0**	23.9

Total current assets	**426.1**	460.9
Property, plant and equipment:		
Property, plant and equipment	**5,249.0**	5,277.9
Less: Accumulated depreciation and amortization	**(2,516.3)**	(2,568.9)
	2,732.7	2,709.0
Construction work in process	**87.8**	150.7
Total net property, plant and equipment	**2,820.5**	2,859.7
Other non-current assets:		
Regulatory assets, non-current (Note 4)	**185.5**	177.8
Intangible assets, net of amortization (Note 1)	**9.0**	6.5
Other deferred assets	**23.1**	33.4
Total other non-current assets	**217.6**	217.7
Total Assets	**3,464.2**	3,538.3

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions	**December 31, 2012**	Decembei 31, 2011
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 6)	**570.4**	0.4
Accounts payable	**79.1**	106.0
Accrued taxes	**92.2**	72.8
Accrued interest	**13.1**	7.9
Customer security deposits	**35.2**	15.8
Regulatory liabilities, current (Note 4)	**0.1**	-
Other current liabilities	**52.1**	46.1
Total current liabilities	**842.2**	249.0
Non-current liabilities:		
Long-term debt (Note 6)	**332.7**	903.0
Deferred taxes (Note 7)	**652.0**	637.7
Taxes payable	**66.0**	93.9
Regulatory liabilities, non-current (Note 4)	**117.3**	118.6
Pension, retiree and other benefits	**61.6**	47.5
Unamortized investment tax credit	**27.4**	29.9
Other deferred credits	**43.0**	77.9
Total non-current liabilities	**1,300.0**	1,908.5

Redeemable preferred stock	**22.9**	22.9
Commitments and contingencies (Note 14)		
Common shareholder's equity:		
Common stock, par value of $0.01 per share 50,000,000 shares authorized, 41,172,173 shares issued and outstanding	**0.4**	0.4
Other paid-in capital	**803.2**	803.1
Accumulated other comprehensive loss	**(38.7)**	(34.7
Retained earnings	**534.2**	589.1
Total common shareholder's equity	**1,299.1**	1,357.9
Total Liabilities and Shareholder's Equity	**3,464.2**	3,538.3

See Notes to 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	781.6	(19.7)	640.3	1,402.6
Year ended December 31, 2010						
Total comprehensive income (loss)				(0.5)	277.7	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
Year ended December 31, 2011						
Total comprehensive income (loss)				(14.4)	193.2	178.8
Common stock dividends					(220.0)	(220.0
Preferred stock dividends					(0.9)	(0.9
Parent company capital contribution			20.0			20.0
Tax effects to equity			1.4			1.4
Employee / Director stock plans			(5.4)			(5.4

Other			4.7		(0.2)	4.5
Ending balance	41,172,173	0.4	803.1	(34.6)	589.0	1,357.9
Year ended December 31, 2012						
Total comprehensive income (loss)				(4.0)	91.2	87.2
Common stock dividends					(145.0)	(145.0
Preferred stock dividends					(0.9)	(0.9
Other			0.1		(0.2)	(0.1
Ending balance	41,172,173	0.4	803.2	(38.6)	534.1	1,299.1

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

See Notes to Financial Statements.

The Dayton Power and Light Company
Notes to Financial Statements

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 and the wholesale sales of power to its DPLER and MC Squared affiliates in Ohio and Illinois. Electricity for **DP&L's** 24 county service area is primarily generated at eight coal-fired electric generating stations and is distributed to more than 513,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense. **DP&L** is a wholly-owned subsidiary of **DPL**. The terms "we," "us," "our" and "ours" are used to refer to **DP&L**.

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

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 1,428 people as of December 31, 2012. Approximately 52% 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. These undivided interests in jointly-owned facilities are accounted for on a pro rata basis in **DP&L's** Financial Statements.

Deferred SECA revenue of $17.8 million at December 31, 2011 was reclassified from Regulatory liabilities to Other deferred credits. The FERC-approved SECA billings were unearned revenue where the earnings process was not complete. 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 $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; at December 31, 2012, there is no remaining balance in Other deferred credits related to SECA. See Note 14 for more information relating to SECA.

Certain immaterial amounts from prior periods, including derivative assets and liabilities and restricted cash, have been reclassified to conform to the current period presentation.

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 stations 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 stations 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 $4.0 million, $4.4 million, and $3.4 million for the years ended December 31, 2012, 2011 and 2010, 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.

At December 31, 2012, **DP&L** did not have any material plant acquisition adjustments or other plant-related adjustments.

Repairs and Maintenance

Costs associated with maintenance activities, primarily station 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 – Changes in Estimates

Depreciation expense is calculated using the straight-line method, which allocates the cost of property over its estimated useful life. For **DP&L's**

generation, transmission and distribution assets, straight-line depreciation is applied monthly on an average composite basis using group rates.

In the third quarter of 2012, a series of events led **DP&L** management to conclude that there was an impairment in the value of certain generating stations (see Note 15 for more information). The effect of this impairment will be to reduce future depreciation related to these stations by approximately $7.1 million per year. The effect in the year ended December 31, 2012 was a reduction of approximately $1.8 million.

In July 2010, **DP&L** 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 **DP&L's** composite depreciation rates should be reduced due to projected useful asset lives which are longer than those previously estimated. **DP&L** adjusted the depreciation rates for its non-regulated generation property effective July 1, 2010, resulting in a net

reduction of depreciation expense. During the year ended December 31, 2011, the net reduction in depreciation expense amounted to $3.4 million ($2.2 million net of tax) compared to the prior year. On an annualized basis going forward, the net reduction in depreciation expense is projected to be approximately $6.8 million ($4.4 million net of tax).

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 4.2% in 2012, 2.5% in 2011 and 2.6% in 2010.

The following is a summary of **DP&L's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2012 and December 31, 2011:

	At December 31,			
$ in millions	**2012**	**Composi te Rate**	2011	Composi e Rate
Regulated:				
Transmission	**380.9**	**2.4%**	367.5	2.4%
Distribution	**1,480.7**	**3.4%**	1,371.5	3.4%
General	**100.0**	**5.4%**	84.8	4.1%
Non-depreciable	**60.1**	**N/A**	59.7	N/A
Total regulated	**2,021.7**		1,883.5	
Unregulated:				
Production / Generation	**3,210.8**	**4.9%**	3,377.9	2.2%
Non-depreciable	**16.5**	**N/A**	16.5	N/A

Total unregulated	**3,227.3**		3,394.4	
Total property, plant and equipment in service	**5,249.0**	**4.2%**	5,277.9	2.5%

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	
Year ended December 31, 2011	
Balance at January 1, 2011	17.5
Accretion expense	0.8
Additions	-
Settlements	(0.5
Estimated cash flow revisions	1.0
Balance at December 31, 2011	18.8
Year ended December 31, 2012	
Accretion expense	0.9
Additions	-
Settlements	(0.4
Estimated cash flow revisions	(0.1
Balance at December 31, 2012	19.2

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 $112.1 million and $112.4 million in estimated costs of removal at December 31, 2012 and 2011, 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 4.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions	
Year ended December 31, 2011	
Balance at January 1, 2011	107.9
Additions	9.4
Settlements	(4.9
Balance at December 31, 2011	112.4
Year ended December 31, 2012	
Additions	10.1
Settlements	(10.4
Balance at December 31, 2012	112.1

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 4.

Effective December 31, 2011, Regulatory assets and Liabilities are presented on a current and non-current basis, depending on the term recovery is anticipated. This change was made to conform with AES' presentation of Regulatory assets and liabilities.

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.

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. 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. 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.

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.

As a result of the Merger, **DPL** and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, **DPL** and its subsidiaries filed a consolidated U.S. federal income tax return. 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 7 for additional information.

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.

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 net basis and recorded as a reduction in revenues in the accompanying Statements of Results of Operations in accordance with AES policy. The amounts for the years ended December 31, 2012, 2011 and 2010 were $50.5 million, $53.7 million and $51.7 million, respectively.

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 11 for additional information. As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date, and none are in existence at December 31, 2012 or 2011.

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.

Restricted Cash

Restricted cash includes cash which is restricted as to withdrawal or usage. The nature of the restrictions include restrictions imposed by agreements related to deposits held as collateral.

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. We have elected not to offset net derivative positions in the financial statements. Accordingly, we do not offset such derivative positions against the fair value of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral under master netting agreements. See Note 10 for additional information.

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.

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 **DP&L** and, in some cases, our partners in commonly owned facilities we operate, for workers' compensation, general liability, property damage, and directors' and officers' liability. **DP&L** is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. In addition, **DP&L** has estimated liabilities for medical, life, and disability claims costs below certain coverage thresholds of third-party providers. We record these additional insurance and claims costs of approximately $17.7 million and $18.9 million for 2012 and 2011, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for workers' compensation, medical, life and disability 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.

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 these transactions:

$ in millions	Years ended December 31, 2012	2011	2010
DP&L revenues:			
Sales to DPLER [a]	350.8	327.0	238.5
Sales to MC Squared	40.0	-	-
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC [b]	(2.6)	(3.1)	(3.3
Expense recoveries for services provided to DPLER [c]	4.0	4.6	5.8
DP&L Customer security deposits:			
Deposits received from DPLER [d]	20.2	-	-

(a) **DP&L** sells power to DPLER and MC Squared to satisfy the electric requirements of their retail customers. The revenue dollars associated with sales to DPLER and MC Squared are recorded as wholesale revenues in **DP&L's** Financial Statements. The increase in **DP&L's** sales to DPLER during the year ended December 31, 2012, compared to the year ended December 31, 2011 is primarily due to customers electing to switch their generation service from **DP&L** to DPLER. **DP&L** started selling physical power to MC Squared during June 2012 and became their sole source of power in September 2012.

(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.

(d) **DP&L** requires credit assurance from the CRES providers serving customers in its service territory because **DP&L** is the default energy provider should the CRES provider fail to fulfill its obligations to provide electricity. Due to **DPL's** credit downgrade, **DP&L** required cash collateral from DPLER.

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 Topic 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. **DP&L** does not have any goodwill.

Recently Issued Accounting Standards

The FASB recently issued ASU 2013-01, "Scope Clarification of Disclosures about Offsetting Assets and Liabilities", to limit the scope of ASU 2011-11 "Disclosures about Offsetting Assets and Liabilities" to derivatives (including bifurcated embedded derivatives), repurchase agreements and reverse repurchase agreements, and securities borrowing and lending transactions. This ASU is effective for annual and interim periods beginning on or after January 1, 2013. The FASB clarified that the disclosures were not intended to included trade receivables and other contracts for financial instruments that may be subject to a master netting arrangement. This new rule is not expected to have a material effect on our overall results of operations, financial position or cash flows.

The FASB recently issued ASU 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income" effective for annual and interim periods beginning after December 15, 2012. The ASU does not change the current requirements for reporting net income or other comprehensive income in financial statements. However, the ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This new rule is not expected to have a material effect on our overall results of operations, financial position or cash flows.

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 present its assets and liabilities on its historical cost basis. Therefore, **DP&L** does not need to show a Predecessor and Successor split of its financial statements.

3. Supplemental Financial Information

	December 31,	
$ in millions	**2012**	2011
Accounts receivable, net		
Unbilled revenue	**48.1**	49.5
Customer receivables	**62.0**	85.8
Amounts due from partners in jointly-owned stations	**19.7**	29.2
Coal sales	**1.6**	1.0
Other	**29.5**	13.9

Provisions for uncollectible accounts	**(0.9)**	(0.9
Total accounts receivable, net	**160.0**	178.5
Inventories		
Fuel and limestone	**67.3**	82.8
Plant materials and supplies	**39.8**	38.6
Other	**1.8**	1.7
Total inventories, at average cost	**108.9**	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 December 31, 2012 and 2011:

	December 31,	
$ in millions (net of tax)	**2012**	2011
Financial instruments	**1.0**	0.6
Cash flow hedges	**2.6**	9.0
Pension and postretirement benefits	**(42.3)**	(44.3
Total	**(38.7)**	(34.7

4. Regulatory Matters

In accordance with GAAP, regulatory assets and liabilities are recorded in the 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 for **DP&L** are as follows:

$ in millions	Type of Recovery [(a)]	Amortization Through	December 31, 2012	2011
Regulatory assets, current:				
TCRR, transmission, ancillary and other PJM-related costs	F	Ongoing	**7.0**	4.7
Power plant emission fees	C	Ongoing	**-**	4.8
Fuel and purchased power recovery costs	C	Ongoing	**11.3**	8.2
Total regulatory assets, current			**18.3**	17.7
Regulatory assets, non-current:				
Deferred recoverable income taxes	B/C	Ongoing	**35.1**	24.1
Pension benefits	C	Ongoing	**88.9**	92.1
Unamortized loss on reacquired debt	C	Ongoing	**11.9**	13.0
Regional transmission organization costs	D	2014	**2.6**	4.1
Deferred storm costs	D		**24.4**	17.9
CCEM smart grid and advanced metering infrastructure costs	D		**6.6**	6.6
CCEM energy efficiency program costs	F	Ongoing	**5.2**	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			**185.5**	177.8
Regulatory liabilities, current:				
Fuel and purchased power recovery costs	C	Ongoing	**0.1**	-
Total regulatory liabilities, current			**0.1**	-
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated property			**112.1**	112.4
Postretirement benefits			**5.0**	6.2
Other			**0.2**	-
Total regulatory liabilities, non-current			**117.3**	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. 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.

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 $3.4 million from certain transactions. On October 4, 2012, we filed testimony on this issue and a hearing was scheduled. In December 2012, we agreed to an immaterial adjustment to settle these issues. The liability was recorded in the fourth quarter of 2012 and will be credited to customers in early 2013.

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 relate to costs incurred to repair the damage caused by storms in the following years:

- 2008 – related to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other 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.
- 2011 – related to five major storms in 2011. On December 21, 2012, **DP&L** filed a request with the PUCO for an accounting order to defer costs and a request for recovery of costs associated with these storms. **DP&L** believes the recovery of these costs is probable at December 31, 2012.
- 2012 – related to storm damage that occurred during final weekend of June 2012. On Augus 10, 2012, **DP&L** filed a request with the PUCO, which was modified on October 19, 2012, for an accounting order to defer the costs associated with this storm damage. On December 19, 2012, the PUCO issued an order permitting partial deferral.

On December 21, 2012, **DP&L** filed a request for recovery of all of these deferred storm costs with the PUCO.

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 that began July 1, 2009 and that is subject to a two-year true-up for any over/under recovery of costs. The two-year true-up was approved by the PUCO and a new rate was set.

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 with what its customers actually use. Based on case precedent in other utilities' cases, the costs are recoverable through **DP&L's** next transmission rate case.

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

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 $3.4 million from certain transactions. On October 4, 2012, we filed testimony on this issue and a hearing was scheduled. In December 2012, we agreed to an immaterial adjustment to settle these issues. The liability was recorded in the fourth quarter of 2012 and will be credited to customers in early 2013.

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.

5. Ownership of Coal-fired Facilities

DP&L and certain 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, 2012, **DP&L** had $36.0 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 within Total net property, plant and equipment in the 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 December 31, 2012, is as follows:

	DP&L Share		DP&L Investment			
	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)
Jointly-owned production units						
Beckjord Unit 6	50.0	207	76	64	-	No
Conesville Unit 4	16.5	129	18	1	11	Yes
East Bend Station	31.0	186	208	136	3	Yes
Killen Station	67.0	402	617	299	5	Yes
Miami Fort Units 7 and 8	36.0	368	363	147	3	Yes
Stuart Station	35.0	808	744	294	12	Yes
Zimmer Station	28.1	365	1,099	642	2	Yes
Transmission (at varying percentages)			96	59	-	
Total		2,465	3,221	1,642	36	
Wholly-owned production unit						
Hutchings Station	100.0	365	-	-	-	No

Currently, our coal-fired electric generation units at Hutchings and Beckjord do not have the 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 commonly owned Unit 6, in December 2014. This was followed by a notification by the joint owners of Beckjord Unit 6 to PJM, dated April 12, 2012, of a planned June 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.

DP&L has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated June 1, 2014. In addition, **DP&L** has notified PJM that the remaining units at Hutchings will no longer operate after May 2013 and will be deactivated on June 1, 2015. The decision to deactivate these units has been made because these 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 final rule was issued on December 16, 2011. We do not believe that any additional accruals are needed related to the Hutchings Station.

As part of the provisional **DPL** purchase accounting adjustments related to the Merger, four stations (Beckjord, Conesville, East Bend and Hutchings) had future expected cash flows that, when discounted, produced a zero fair market value. Since **DP&L** did not apply push down accounting, this valuation did not affect the book value of these stations' valuation at **DP&L**. In the third quarter of 2012, **DP&L** performed an impairment review of its stations, and recorded an impairment of $80.8 million related to two of the stations, Conesville and Hutchings. See Note 15 for more information on this impairment.

6. Debt Obligations

Long-term debt is as follows:

Long-term debt

$ in millions	**December 31, 2012**	December 31, 2011
First mortgage bonds maturing in October 2013 - 5.125%	-	470.0
Pollution control series maturing in January 2028 - 4.7%	**35.3**	35.3
Pollution control series maturing in January 2034 - 4.8%	**179.1**	179.1
Pollution control series maturing in September 2036 - 4.8%	**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
U.S. Government note maturing in February 2061 - 4.2%	**18.3**	18.5
Capital lease obligations	**0.1**	0.4
Unamortized debt discount	**(0.1)**	(0.3)
Total long-term debt	**332.7**	903.0

Current portion - long-term debt

$ in millions	**December 31, 2012**	December 31, 2011
First mortgage bonds maturing in October 2013 - 5.125%	**470.0**	-
Pollution control series maturing in November 2040 - variable rates: 0.04% - 0.26% and 0.06% - 0.32% (a)	**100.0**	-
U.S. Government note maturing in February 2061 -	**0.1**	0.1

4.2%		
Capital lease obligations	**0.3**	0.3
Total current portion - long-term debt	**570.4**	0.4

(a) - range of interest rates for the twelve months ended December 31, 2012 and December 31, 2011, respectively

At December 31, 2012, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions	
Due within one year	570.4
Due within two years	0.2
Due within three years	0.1
Due within four years	0.1
Due within five years	0.1
Thereafter	332.3
	903.2
Unamortized discount	(0.1
Total long-term debt	903.1

On November 21, 2006, **DP&L** entered into a $220.0 million unsecured revolving credit agreement. This agreement was terminated by **DP&L** on August 29, 2011.

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. Since this letter of credit facility expires in December 2013, at which point the bondholders could tender the bonds, we have reflected these outstanding bonds as a current liability. Management will continue to monitor

and evaluate market conditions over the next several months and make a determination to either seek a renewal of this standby letter of credit or to explore alternative financing arrangements. Fees associated with this letter of credit facility were not material during the years ended December 31, 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 December 31, 2012 or 2011. Fees associated with this revolving credit facility were not material during the twelve months ended December 31, 2012 or the period between April 20, 2010 and December 31, 2011. This facility also contains a $50.0 million letter of credit sublimit. As of December 31, 2012 and 2011, **DP&L** had no outstanding letters of credit against the facility.

On March 1, 2011, **DP&L** completed the purchase of $18.7 million electric transmission and distribution assets from the federal government that are located at the Wright-Patterson Air Force Base (WPAFB). **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 December 31, 2012 or 2011. Fees associated with this revolving credit facility were not material during the year ended December 31, 2012 or the five months ended December 31, 2011. This facility also contains a $50.0 million letter of credit sublimit. As of December 31, 2012 and 2011, **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.

7. Income Taxes

DP&L's components of income tax expense were as follows:

$ in millions	**Year ended December 31, 2012**	Year ended December 31, 2011	Year ended December 31, 2010
Computation of tax expense			
Federal income tax expense / (benefit)[(a)]	**50.9**	103.8	144.2
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**(2.0)**	1.4	1.9
Depreciation of AFUDC - Equity	**3.0**	(3.2)	(2.2
Investment tax credit amortized	**(2.5)**	(2.5)	(2.8
Section 199 - domestic production deduction	**(2.5)**	(4.9)	(9.1
Non-deductible merger-related compensation	**0.6**	3.6	-
ESOP	**-**	13.6	-
Compensation and benefits	**-**	(5.3)	-
Other, net[(b)]	**7.6**	(2.3)	3.2
Total tax expense	**55.1**	104.2	135.2

Components of Tax Expense			
Federal - current	**52.1**	54.9	83.1
State and Local - current	**1.0**	0.9	0.8
Total current	**53.1**	55.8	83.9
Federal - deferred	**4.7**	47.1	50.1
State and local - deferred	**(2.7)**	1.3	1.2
Total deferred	**2.0**	48.4	51.3
Total tax expense	**55.1**	104.2	135.2

	December 31,	
$ in millions	**2012**	2011
Net non-current Assets / (Liabilities)		
Depreciation / property basis	**(622.1)**	(613.1
Income taxes recoverable	**(12.3)**	(8.6
Regulatory assets	**(20.6)**	(18.8
Investment tax credit	**9.6**	10.5
Compensation and employee benefits	**0.3**	(4.2
Other	**(6.9)**	(3.5
Net non-current liabilities	**(652.0)**	(637.7
Net current Assets / (Liabilities) [(c)]		
Other	**2.0**	1.5
Net current assets	**2.0**	1.5

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

(b) Includes expense of $7.6 million and benefits of $2.4 million and $0.3 million in 2012, 2011 and 2010, respectively, of income tax related to adjustments from prior years.

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

The following table presents the tax (benefit) / expense related to pensions, postretirement benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

$ in millions	**Year ended December 31, 2012**	Year ended December 31, 2011	Year ended December 31, 2010
Tax expense / (benefit)	**(0.8)**	(7.2)	0.1

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 **DP&L** is as follows:

$ in millions	
Year ended December 31, 2011	
Balance at January 1, 2011	19.4
Tax positions taken during prior periods	2.0
Tax positions taken during current period	3.6
Balance at December 31, 2011	25.0
Year ended December 31, 2012	
Tax positions taken during prior periods	(6.3)
Tax positions taken during current period	(0.4)
Balance at December 31, 2012	18.3

Of the December 31, 2012 balance of unrecognized tax benefits, $19.4 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 following table represents the amounts accrued as well as the expense / (benefit) recorded as of and for the periods noted below:

Amounts in Balance Sheet $ in millions	**Year ended December 31, 2012**	Year ended December 31, 2011	Year ended December 31, 2010
Liability	**0.8**	0.9	0.3

Amounts in Statement of Operations $ in millions	**Year ended December 31, 2012**	Year ended December 31, 2011	Year ended December 31, 2010
Expense / (benefit)	**(0.1)**	0.6	0.4

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

U.S. Federal – 2007 and forward
State and Local – 2007 and forward

All of the unrecognized tax benefits are expected to settle 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 was completed on January 18, 2013 and we do not expect the results of this examination to have a material effect on our financial condition, results of operations and cash flows.

As a result of the Merger, **DPL** and its subsidiaries file U.S. federal income tax returns as a part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, **DPL** and its subsidiaries filed a consolidated U.S. federal income tax return. 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.

8. Pension and Postretirement Benefits

DP&L sponsors a traditional defined benefit pension plan for substantially all employees of **DPL**. 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 traditional defined benefit pension plan is based primarily on compensation and years of service. As of December 31, 2010, this traditional 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 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.

All **DP&L** management employees beginning employment on or after January 1, 2011 are enrolled in a cash balance pension plan. Similar to the traditional 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 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 retired key executives. The SERP was replaced by the DPL Inc. Supplemental Executive Defined Contribution Retirement Plan (SEDCRP) effective January 1, 2006, which is for certain active and former key executives. 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. Per the SEDCRP plan document, the balances in the SEDCRP, including earnings on contributions, were paid out to participants in December

2011, following the merger with AES on November 28, 2011. However, the SEDCRP continued and a 2011 contribution was calculated in March 2012. The SEDCRP was terminated by the Board of Directors as of December 31, 2012, but a 2012 contribution will be calculated and the balances, including earnings on contributions, will be paid to participants in 2013. 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 $1.1 million and $0.8 million at December 31, 2012 and 2011, 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. **DP&L** made discretionary contributions of $40.0 million and $40.0 million to the defined benefit plan during the year ended December 31, 2011 and the year ended December 31, 2010, respectively.

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.

We recognize an asset for a plan's overfunded status and 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. For the transmission and distribution areas of our electric business, these amounts are recorded as regulatory assets and liabilities which 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 through customer rates.

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, 2012 and 2011. The amounts presented in the following tables for pension include the collective bargaining plan formula, traditional management plan formula and cash balance plan formula and the SERP in the aggregate. The amounts presented for postretirement include both health and life insurance benefits.

$ in millions	**Pension**	
	Years ended December 31,	
	2012	2011

Change in benefit obligation		
Benefit obligation at beginning of period	**365.2**	333.8
Service cost	**6.2**	5.0
Interest cost	**17.3**	17.0
Plan amendments	**-**	7.2
Actuarial loss	**29.1**	21.6
Benefits paid	**(22.2)**	(19.4
Benefit obligation at end of period	**395.6**	365.2
Change in plan assets		
Fair value of plan assets at beginning of period	**335.9**	291.8
Actual return on plan assets	**46.2**	23.1
Contributions to plan assets	**1.5**	40.4
Benefits paid	**(22.2)**	(19.4
Fair value of plan assets at end of period	**361.4**	335.9
Funded status of plan	**(34.2)**	(29.3

$ in millions	**Postretirement**	
	Years ended December 31,	
	2012	2011
Change in benefit obligation		
Benefit obligation at beginning of period	**21.7**	23.7
Service cost	**0.1**	0.1
Interest cost	**0.9**	1.0
Actuarial (gain) / loss	**1.2**	(1.3
Benefits paid	**(1.7)**	(2.0
Medicare Part D reimbursement	**0.2**	0.2
Benefit obligation at end of period	**22.4**	21.7
Change in plan assets		
Fair value of plan assets at beginning of period	**4.5**	4.8
Actual return on plan assets	**0.2**	0.2
Contributions to plan assets	**1.2**	1.5
Benefits paid	**(1.7)**	(2.0
Fair value of plan assets at end of period	**4.2**	4.5
Funded status of plan	**(18.2)**	(17.2

$ in millions	**Pension**		**Postretirement**	
	December 31,		**December 31,**	
	2012	2011	**2012**	2011
Amounts recognized in the				

Balance sheets at December 31				
Current liabilities	**(0.4)**	(1.3)	**(0.6)**	(0.6
Non-current liabilities	**(33.8)**	(27.9)	**(17.6)**	(16.6
Net liability at December 31	**(34.2)**	(29.2)	**(18.2)**	(17.2
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost	**19.0**	21.9	**0.8**	0.9
Net actuarial loss / (gain)	**136.1**	140.2	**(5.7)**	(7.7
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**155.1**	162.1	**(4.9)**	(6.8
Recorded as:				
Regulatory asset	**88.0**	91.1	**0.5**	1.0
Regulatory liability	**-**	-	**(5.0)**	(6.6
Accumulated other comprehensive income	**67.1**	71.0	**(0.4)**	(1.2
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**155.1**	162.1	**(4.9)**	(6.8

The accumulated benefit obligation for our defined benefit pension plans was $382.5 million and $355.5 million at December 31, 2012 and 2011, respectively.

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

Net Periodic Benefit Cost - Pension

	Years ended December 31,		
$ in millions	**2012**	2011	2010
Service cost	**6.2**	5.0	4.8
Interest cost	**17.3**	17.0	17.7
Expected return on assets [(a)]	**(22.7)**	(24.5)	(22.4
Amortization of unrecognized:			
Actuarial loss	**8.8**	8.0	7.2
Prior service cost	**2.8**	2.1	3.7
Net periodic benefit cost before adjustments	**12.4**	7.6	11.0
Settlement Expense	**0.6**	-	-
Net periodic benefit cost after adjustments	**13.0**	7.6	11.0

(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 $346.0 million in 2012, $335.0 million in 2011, and $274.0 million in 2010.

Net Periodic Benefit Income - Postretirement

	Years ended December 31,		
$ in millions	**2012**	2011	2010
Service cost	**0.1**	0.1	0.1
Interest cost	**0.9**	1.0	1.2
Expected return on assets [a]	**(0.3)**	(0.3)	(0.3
Amortization of unrecognized:			
Actuarial gain	**(0.9)**	(1.1)	(1.1
Prior service cost	**0.1**	0.1	0.1
Net periodic benefit income before adjustments	**(0.1)**	(0.2)	-

Pension

	Years ended December 31,		
$ in millions	**2012**	2011	2010
Net actuarial loss	**5.2**	22.8	1.9
Prior service cost	**-**	7.1	-
Reversal of amortization item:			
Net actuarial gain	**(9.4)**	(8.0)	(7.2
Prior service credit	**(2.8)**	(2.0)	(3.7
Transition asset	**-**	-	-
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**(7.0)**	19.9	(9.0
Total recognized in net periodic benefit cost Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**6.0**	27.5	2.0

Postretirement

	Years ended December 31,		
$ in millions	**2012**	2011	2010
Net actuarial loss / (gain)	**1.1**	(1.3)	(1.9
Prior service credit	**-**	-	-
Reversal of amortization item:			
Net actuarial loss	**0.9**	1.2	1.1
Prior service credit	**(0.1)**	(0.1)	(0.1
Transition asset	**-**	-	-
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**1.9**	(0.2)	(0.9

Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**1.8**	(0.4)	(0.9

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2013 are:

$ in millions	Pension	Postretirement
Net actuarial loss / (gain)	9.3	(0.7
Prior service cost	2.8	0.1

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 2013, we are maintaining our expected long-term rate of return on assets assumption of 7.00% for pension plan assets and 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 Aon AA Above Median Yield Curve which represents a portfolio of Above Median 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 during the years ended December 31, 2012, 2011 and 2010 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2012	2011	2010	**2012**	2011	201(
Discount rate for obligations	**4.04 %**	4.88 %	5.31 %	**3.75 %**	4.62 %	4.9E %
Rate of compensation increases	**3.94 %**	3.94 %	3.94 %	**N/A**	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2012, 2011 and 2010 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2012	2011	2010	**2012**	2011	2010
Discount rate	**4.88 %**	5.31 %	5.75 %	**4.62 %**	4.96 %	5.35 %
Expected rate of return on plan assets	**7.00 %**	8.00 %	8.50 %	**6.00 %**	6.00 %	6.00 %
Rate of compensation increases	**3.94 %**	3.94 %	4.44 %	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2012, 2011 and 2010 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2012	2011	2010	**2012**	2011	2010
Pre - age 65						
Current health care cost trend rate	**8.50 %**	8.50 %	9.50 %	**8.00 %**	8.50 %	8.50 %
Year trend reaches ultimate	**2019**	2018	2015	**2019**	2019	2018
Post - age 65						
Current health care cost trend rate	**8.00 %**	8.00 %	9.00 %	**7.50 %**	8.00 %	8.00 %
Year trend reaches ultimate	**2018**	2017	2014	**2018**	2018	2017
Ultimate health care cost trend rate	**5.00 %**	5.00 %	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	0.1	(0.1
Benefit obligation	1.2	(1.0

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
2013	22.1	2.5
2014	22.5	2.4
2015	23.0	2.3
2016	23.3	2.1
2017	23.7	1.9
2018-2022	122.6	7.6

We expect to make contributions of $0.4 million to our SERP in 2013 to cover benefit payments. We also expect to contribute $2.1 million to our other postretirement benefit plans in 2013 to cover benefit payments.

The Pension Protection Act of 2006 (the Act) 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 2012 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 116.56% and is estimated to be 116.56% until the 2013 status is certified in September 2013 for the 2013 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.

The fair values of our pension plan assets at December 31, 2012 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2012

Asset Category $ in millions	**Market Value at December 31, 2012**	**Quoted prices in active markets for identical assets** (Level 1)	**Significant observable inputs** (Level 2)	**Significant unobservabl inputs** (Level 3)
Equity securities [(a)]				
Small/Mid cap equity	14.3	-	14.3	-
Large cap equity	50.5	-	50.5	-
International equity	37.0	-	37.0	-
Total equity securities	101.8	-	101.8	-
Debt Securities [(b)]				
Emerging markets debt	7.4	-	7.4	-
High yield bond	12.7	-	12.7	-
Long duration fund	188.6	-	188.6	-
Total debt securities	208.7	-	208.7	-
Cash and cash equivalents [(c)]				
Cash	13.9	13.9	-	-
Other investments [(d)]				
Limited partnership interest	-	-	-	-
Common collective fund	37.0	-	-	37.C
Total other investments	37.0	-	-	37.C
Total pension plan assets	361.4	13.9	310.5	37.C

(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 funds.

(b) This category includes investments in investment-grade fixed-income instruments that are designed to mirror the term of the pension assets and generally have a tenor between 10 and 30 years. 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 and the proceeds received from the sale of the DPL common stock, which was cashed out at $30/share. 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 of the fund 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.

The fair values of our pension plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011

Asset Category $ in millions	**Market Value at December 31, 2011**	**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	16.2	-	16.2	-
Large cap equity	54.5	-	54.5	-
International equity	34.2	-	34.2	-
Total equity securities	104.9	-	104.9	-
Debt Securities [b]				
Long duration fund	130.8	-	130.8	-
Total debt securities	130.8	-	130.8	-
Cash and cash equivalents [c]				
Cash	28.0	28.0	-	-
Other investments [d]				
Limited partnership interest	0.8	-	-	0.8
Common collective fund	71.4	-	-	71.4
Total other investments	72.2	-	-	72.2
Total pension plan assets	335.9	28.0	235.7	72.2

(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 of the fund 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.

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

Change in fair value measurements of pension assets using significant unobservable inputs (Level 3)

$ in millions	Limited Partnership Interest	Common Collective Fund
Year ended December 31, 2011		
Beginning balance January 1, 2011	2.8	57.4
Actual return on plan assets:		
Relating to assets still held at the reporting date	(0.8)	(1.4
Relating to assets sold during the period	-	-
Purchases, sales, and settlements	(1.2)	15.4
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2011	0.8	71.4
Year ended December 31, 2012		
Actual return on plan assets:		
Relating to assets still held at the reporting date	-	**1.4**
Relating to assets sold during the period	**0.9**	-
Purchases, sales, and settlements	**(1.7)**	**(35.8**
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2012	**(0.0)**	**37.0**

The fair values of our other postretirement benefit plan assets at December 31, 2012 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2012

Asset Category $ in millions	Market Value at December 31, 2012	Quoted prices in active markets for identical assets	Significant observable inputs	Significant unobservable inputs
		(Level 1)	(Level 2)	(Level 3)
JP Morgan Core Bond Fund [(a)]	4.2	-	4.2	-

(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, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011

Asset Category $ in millions	Market Value at December 31, 2011	Quoted prices in active markets for identical assets	Significant observable inputs	Significant unobservable inputs
		(Level 1)	(Level 2)	(Level 3)
JP Morgan Core Bond Fund [(a)]	4.5	-	4.5	-

(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.

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. ESOP shares that were used to fund matching contributions to **DP&L's** 401(k) vested after either two or three years of service in accordance with the match formula effective for the respective plan match year; other compensation shares awarded vested immediately. In 1992, the ESOP Plan entered into a $90 million loan agreement with **DPL** in order to purchase shares of **DPL** common stock in the open market. The leveraged ESOP was funded by an exempt loan, which was secured by the ESOP shares. As debt service payments were made on the loan, shares were released on a pro rata basis. 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 were used to repay the principal and interest on the ESOP loan to **DPL**. Dividends on the allocated shares were charged to retained earnings and the share value of these dividends was allocated to participants.

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 million on the loan with **DPL**, using the merger proceeds from **DPL** common stock held within the ESOP suspense account.

Compensation expense recorded, based on the fair value of the shares committed to be released, amounted to $4.8 million and $6.7 million in the years ended 2011 and 2010, respectively.

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 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, 2012 and 2011. See also Note 10 for the fair values of our derivative instruments.

	December 31, 2012		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	**4.0**	**5.1**	3.9	4.4
Debt securities	**4.6**	**5.0**	5.0	5.5
Multi-strategy fund	**0.3**	**0.3**	0.3	0.2
Total assets	**9.1**	**10.6**	9.4	10.3
Liabilities				
Debt	**903.1**	**926.9**	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 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 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 $1.6 million ($1.0 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2012 and $1.0 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2011.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. $0.1 million ($0.1 million after tax) of unrealized gains were reversed into earnings during the past twelve months. $0.1 million ($0.1 million after tax) of unrealized gains are expected to be reversed to earnings over 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, 2012 and 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 December 31, 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 December 31, 2012**	Fair Value at December 31, 2011	Unfunded Commitments	Redempt on Frequency
Money market fund [(a)]	**0.2**	0.2	-	Immedia e
Equity securities [(b)]	**5.1**	4.4	-	Immedia e
Debt Securities [(c)]	**5.0**	5.5	-	Immedia e
Multi-strategy fund [(d)]	**0.3**	0.2	-	Immedia e
Total	**10.6**	10.3	-	

(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 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 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, 2012 and 2011.

The fair value of assets and liabilities at December 31, 2012 and 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

		Level 1	Level 2	Level 3
$ in millions	Fair Value at December 31, 2012(a)	Based on Quoted Prices in Active Markets	Other observable inputs	Unobserv able inputs
Assets				
Master trust assets				
Money market funds	0.2	0.2	-	-
Equity securities	5.1	-	5.1	-
Debt securities	5.0	-	5.0	-
Multi-strategy fund	0.3	-	0.3	-
Total Master trust assets	10.6	0.2	10.4	-

Derivative assets				
Heating oil futures	**0.2**	**0.2**	**-**	**-**
Forward power contracts	**7.3**	**-**	**7.3**	**-**
Total derivative assets	**7.5**	**0.2**	**7.3**	**-**
Total assets	**18.1**	**0.4**	**17.7**	**-**
Liabilities				
Derivative liabilities				
FTRs	**(0.1)**	**-**	**-**	**(0.1**
Forward power contracts	**(11.6)**	**-**	**(11.6)**	**-**
Total derivative liabilities	**(11.7)**	**-**	**(11.6)**	**(0.1**
Long Term debt	**(926.9)**	**-**	**(908.0)**	**(18.9**
Total liabilities	**(938.6)**	**-**	**(919.6)**	**(19.0**

(a) Includes credit valuation adjustment.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

$ in millions	Fair Value at December 31, 2011(a)	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	-	4.1	-
Total derivative assets	6.0	1.8	4.2	-
Total assets	16.3	1.8	14.5	-
Liabilities				
Derivative liabilities				
Forward NYMEX coal contracts	(14.5)	-	(14.5)	-

Forward power contracts	(5.0)	-	(5.0)	-
Total derivative liabilities	(19.5)	-	(19.5)	-
Total liabilities	(19.5)	-	(19.5)	-

(a) Includes credit valuation adjustment.

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 note 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 98% 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. A new ARO liability in the amount of $0.1 million was established in 2012 associated with a gypsum landfill disposal site that is presently under construction. This increase in 2012 was offset by a $0.1 million reduction in ARO for asbestos as a result of an acceleration of removal and remediation activities. During the year ended December 31, 2011, there were gross additions of $1.0 million to our existing river structures, asbestos, ash landfill and underground storage tank AROS.

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 December 31, 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	6.9	-	6.9
Heating Oil Futures	Mark to Market	Gallons	1,764.0	-	1,764.(
Forward Power Contracts	Cash Flow Hedge	MWh	1,021.0	(2,197.9)	(1,176.9
Forward Power Contracts	Mark to Market	MWh	2,296.6	(4,760.4)	(2,463.8

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.(
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 [(a)]	Mark to Market	Tons	2,015.0	-	2,015.(

(a) Includes our partners' share for the jointly-owned stations 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 values of cash flow hedges 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.

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

	Year ended December 31, 2012		Year ended December 31, 2011		Year ended December 31, 2010	
$ in millions	**Power**	**Intere st Rate Hedge**	Power	Interes t Rate Hedge	Power	Interes Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI [(a)]	**(0.8)**	**9.8**	(1.8)	12.2	(1.4)	14.7
Net gains / (losses) associated with current period hedging transactions	**(3.0)**	**-**	(1.2)	-	3.1	-
Net gains reclassified to earnings:						
Interest Expense	**-**	**(2.5)**	-	(2.4)	-	(2.5
Revenues	**(1.1)**	**-**	1.2	-	(3.5)	-
Purchased Power	**0.2**	**-**	1.0	-	-	-
Ending accumulated derivative gain / (loss) in AOCI	**(4.7)**	**7.3**	(0.8)	9.8	(1.8)	12.2

Net gains or losses associated with the ineffective portion of the hedging transactions were immaterial in the years ended December 31, 2012, 2011 and 2010.

Portion expected to be	**(6.2)**	**(2.5)**

reclassified to earnings in the next twelve months [a]		
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**24**	-

(a) 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 shows the fair value and balance sheet classification of **DP&L's** derivative instruments designated as hedging instruments at December 31, 2012 and 2011.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2012

$ in millions	Fair Value [a]	Balance Sheet Location
Short-term Derivative Positions		
Forward Power Contracts in an Asset Position	**0.5**	Other prepayments and current assets
Forward Power Contracts in a Liability Position	**(6.7)**	Other current liabilities
Total Short-term Cash Flow Hedges	**(6.2)**	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	**0.5**	Other deferred assets
Forward Power Contracts in a Liability Position	**(1.5)**	Other deferred credits
Total Long-term Cash Flow Hedges	**(1.0)**	
Total Cash Flow Hedges	**(7.2)**	

(a) Includes credit valuation adjustment.

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

$ in millions	Fair Value [a]	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)	

(a) Includes credit valuation adjustment.

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 years ended December 31, 2012 and 2011.

Year ended December 31, 2012					
$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	**14.5**	**(1.6)**	**(0.2)**	**3.0**	**15.7**
Realized gain / (loss)	**(29.5)**	**1.9**	**0.5**	**4.9**	**(22.2**
Total	**(15.0)**	**0.3**	**0.3**	**7.9**	**(6.5**
Recorded on Balance Sheet:					
Partners' share of gain	**4.2**	**-**	**-**	**-**	**4.2**
Regulatory (asset) / liability	**1.0**	**(0.6)**	**-**	**-**	**0.4**
Recorded in Income Statement: gain / (loss)					
Revenue	**-**	**-**	**-**	**2.7**	**2.7**
Purchased Power	**-**	**-**	**0.3**	**5.2**	**5.5**
Fuel	**(20.2)**	**0.7**	**-**	**-**	**(19.5**
O&M	**-**	**0.2**	**-**	**-**	**0.2**
Total	**(15.0)**	**0.3**	**0.3**	**7.9**	**(6.5**

Year ended December 31, 2011					
$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	(52.1)	0.1	(0.1)	0.3	(51.8
Realized gain / (loss)	7.5	2.3	(0.6)	(1.4)	7.8
Total	(44.6)	2.4	(0.7)	(1.1)	(44.0
Recorded on Balance Sheet:					
Partners' share of loss	(26.1)	-	-	-	(26.1
Regulatory asset	(7.1)	-	-	-	(7.1
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	2.5	2.5
Purchased Power	-	-	(0.7)	(3.6)	(4.3
Fuel	(11.4)	2.2	-	-	(9.2
O&M	-	0.2	-	-	0.2
Total	(44.6)	2.4	(0.7)	(1.1)	(44.0

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
	Year ended December 31, 2010				
Derivatives not designated as hedging instruments					
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	20.1	-	-	-	20.1
Regulatory liability	4.6	1.1	-	-	5.7
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	-	-
Purchased Power	-	-	(2.1)	-	(2.1
Fuel	12.0	0.1	-	-	12.1
O&M	-	-	-	-	-
Total	36.7	1.2	(2.1)	-	35.8

The following tables show the fair value and balance sheet classification of **DP&L's** derivative instruments not designated as hedging instruments at December 31, 2012 and 2011.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
December 31, 2012

$ in millions	Fair Value [a]	Balance Sheet Location
Short-term Derivative Positions		
FTRs in a Liability Position	**(0.1)**	Other current liabilities
Forward Power Contracts in an Asset Position	**2.8**	Other prepayments and current assets
Forward Power Contracts in a Liability Position	**(2.7)**	Other current liabilities
Heating Oil Futures in an Asset Position	**0.2**	Other prepayments and current assets
Total Short-term Derivative MTM Positions	**0.2**	
Long-term Derivative Positions		
Forward Power Contracts in an Asset Position	**3.6**	Other deferred assets
Forward Power Contracts in a Liability Position	**(0.7)**	Other deferred credits
Total Long-term Derivative MTM Positions	**2.9**	
Net MTM Position	**3.1**	

(a) Includes credit valuation adjustment.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments
December 31, 2011

$ in millions	Fair Value (a)	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)	

(a) Includes credit valuation adjustment.

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 November 2012 have triggered the provisions discussed above with some of our counterparties. Since our debt has fallen below investment grade, some of our counterparties to the derivative instruments have requested collateralization of the MTM loss.

The aggregate fair value of **DP&L's** derivative instruments that are in a MTM loss position at December 31, 2012 is $11.7 million. This amount is offset by $3.6 million in a broker margin account and with other counterparties

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 $6.4 million. If **DP&L** debt were to fall below investment grade, **DP&L** could be required to post collateral for the remaining $1.7 million.

11. Share-based Compensation

In April 2006, **DPL's** shareholders approved The DPL Inc. Equity and Performance Incentive Plan (the EPIP) which became immediately effective for a term of ten years. The Compensation Committee of the Board of Directors designated the employees and directors eligible to participate in the EPIP and the times and types of awards to be granted. A total of 4,500,000 shares of **DPL** common stock had been reserved for issuance under the EPIP. The EPIP also covered certain employees of **DP&L**.

As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date. The remaining compensation expense of $5.5 million ($3.6 million after tax) was expensed as of the Merger date.

The following table summarizes share-based compensation expense (note that there is no share-based compensation activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Restricted stock units	-	-
Performance shares	2.4	2.1
Restricted shares	5.3	1.7
Non-employee directors' RSUs [(a)]	0.6	0.4
Management performance shares	1.8	0.5
Share-based compensation included in Operation and maintenance expense	10.1	4.7
Income tax benefit	(3.5)	(1.6
Total share-based compensation, net of tax	6.6	3.1

(a) Includes an amount associated with compensation awarded to DPL's Board of Directors which is immaterial in total.

Share-based awards issued in **DPL's** common stock were distributed from treasury stock prior to the Merger; as of the Merger date, remaining share-based awards were distributed in cash in accordance with the Merger agreement.

Determining Fair Value

Valuation and Amortization Method – We estimated the fair value of performance shares using a Monte Carlo simulation; restricted shares were valued at the closing market price on the day of grant and the Directors' RSUs were valued at the closing market price on the day prior to the grant date. We amortized 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 were based on the historical volatility of **DPL** common stock. The volatility range captured the high and low volatility values for each award granted based on its specific terms.

Expected Life – The expected life assumption represented the estimated period of time from the grant date until the exercise date and reflected historical employee exercise patterns.

Risk-Free Interest Rate – The risk-free interest rate for the expected term of the award was 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 was used for valuing an award with a five year expected life.

Expected Dividend Yield – The expected dividend yield was 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 was based on **DPL's** historical experience, adjusted as necessary to reflect special circumstances.

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 were granted under The DPL Inc. Stock Option Plan. Prior to the Merger, all outstanding stock options had been exercised or had expired.

Summarized stock option activity was as follows (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Options:		
Outstanding at beginning of period	351,500	417,500
Granted	-	-
Exercised	(75,500)	(66,000)
Expired	(276,000)	-
Forfeited	-	-
Outstanding at end of period	-	351,500
Exercisable at end of period	-	351,500
Weighted average option prices per share:		
Outstanding at beginning of period	28.04	27.16
Granted	-	-
Exercised	21.02	21.00
Expired	29.42	-
Forfeited	-	-
Outstanding at end of period	-	28.04
Exercisable at end of period	-	28.04

The following table reflects information about stock option activity during the period (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Weighted-average grant date fair value of options granted during the period	-	-
Intrinsic value of options exercised during the period	0.7	0.5
Proceeds from options exercised during the period	1.6	1.4
Excess tax benefit from proceeds of options exercised	0.2	0.1
Fair value of options that vested during the period	-	-
Unrecognized compensation expense	-	-
Weighted-average period to recognize compensation expense (in years)	-	-

Restricted Stock Units (RSUs)

RSUs were granted to certain key employees prior to 2001. As of the Merger date, there were no RSUs outstanding.

Summarized RSU activity was as follows (note that there is no RSU activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
RSUs:		
Outstanding at beginning of period	-	3,311
Granted	-	-
Dividends	-	-
Exercised	-	(3,311
Forfeited	-	-
Outstanding at end of period	-	-
Exercisable at end of period	-	-

Performance Shares

Under the EPIP, the Board of Directors adopted a Long-Term Incentive Plan (LTIP) under which **DPL** granted a targeted number of performance shares of common stock to executives. Grants under the LTIP were awarded based on a Total Shareholder Return Relative to Peers performance. The Total Shareholder Return Relative to Peers is considered a market condition in accordance with the accounting guidance for share-based compensation.

At the Merger date, vesting for all non-vested LTIP performance shares was accelerated on a pro rata basis and such shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized performance share activity was as follows (note that there is no performance share activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Performance shares:		
Outstanding at beginning of period	278,334	237,704
Granted	85,093	161,534
Dividends	(198,699)	(91,253
Exercised	(66,836)	-
Forfeited	(97,892)	(29,651
Outstanding at end of period	-	278,334
Exercisable at end of period	-	66,836

The following table reflects information about performance share activity during the period (note that there is no performance share activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Weighted-average grant date fair value of performance shares granted during the period	2.2	2.9
Intrinsic value of performance shares exercised during the period	6.0	2.5
Proceeds from performance shares exercised during the period	-	-
Excess tax benefit from proceeds of performance shares exercised	0.7	-
Fair value of performance shares that vested during the period	4.7	1.6
Unrecognized compensation expense	-	2.4
Weighted-average period to recognize compensation expense (in years)	-	1.7

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:

	Years ended December 31,	
$ in millions	2011	2010
Expected volatility	24.0%	24.3%
Weighted-average expected volatility	24.0%	24.3%
Expected life (years)	3.0	3.0
Expected dividends	5.0%	4.5%
Weighted-average expected dividends	5.0%	4.5%

Risk-free interest rate	1.2%	1.4%

Restricted Shares

Under the EPIP, the Board of Directors granted shares of **DPL** Restricted Shares to various executives and other key employees. These Restricted Shares were registered in the recipient's name, carried full voting privileges, received dividends as declared and paid on all **DPL** common stock and vested after a specified service period.

In July 2008, the Board of Directors granted Restricted Share awards under the EPIP to a select group of management employees. The management Restricted Share awards had a three-year requisite service period, carried full voting privileges and received 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 was a Restricted Share grant and the second part was a matching Restricted Share grant. These Restricted Share grants generally vested after five years if the participant remained continuously employed with **DPL** or a **DPL** subsidiary and if the year-over-year average EPS had increased by at least 1% from 2009 to 2013. Under the matching Restricted Share grant, participants had a three-year period from the date of plan implementation during which they could purchase **DPL** common stock equal in value to up to two times their 2009 base salary. **DPL** matched the shares purchased with another grant of Restricted Shares (matching Restricted Share grant). The percentage match by **DPL** is detailed in the table below. The matching Restricted Share grant would have generally vested over a three-year period if the participant continued to hold the originally purchased shares and remained continuously employed with **DPL** or a **DPL** subsidiary. The Restricted Shares were registered in the recipient's name, carried full voting privileges and received dividends as declared and paid on all **DPL** common stock.

The matching criteria were:

Value (Cost Basis) of Shared Purchased as a % of 2009 Base Salary	Company % Match of Value of Shares Purchased
1% to 25%	25%
>25% to 50%	50%
>50% to 100%	75%
>100% to 200%	125%

The matching percentage was applied on a cumulative basis and the resulting Restricted Share grant was adjusted at the end of each calendar quarter. As a result of the Merger, the matching Restricted Share grants were suspended in March 2011.

In February 2011, the Board of Directors granted a targeted number of time-vested Restricted Shares to executives under the LTIP. These Restricted Shares did not carry voting privileges nor did they receive dividend rights during the vesting period. In addition, a one-year holding period was implemented after the three-year vesting period was completed.

Restricted Shares could only be awarded in **DPL** common stock.

At the Merger date, vesting for all non-vested Restricted Shares was accelerated and all outstanding shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized Restricted Share activity was as follows (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Restricted shares:		
Outstanding at beginning of period	219,391	218,197
Granted	67,346	42,977
Exercised	(286,737)	(20,803
Forfeited	-	(20,980
Outstanding at end of period	-	219,391
Exercisable at end of period	-	-

The following table reflects information about Restricted Share activity during the period (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Weighted-average grant date fair value of restricted shares granted during the period	1.8	1.1
Intrinsic value of restricted shares exercised during the period	8.6	0.4
Proceeds from restricted shares exercised during the period	-	-
Excess tax benefit from proceeds of restricted shares exercised	0.5	0.1
Fair value of restricted shares that vested during the period	7.5	0.6
Unrecognized compensation expense	-	3.4
Weighted-average period to recognize compensation expense (in years)	-	2.7

Non-Employee Director RSUs

Under the EPIP, as part of their annual compensation for service to **DPL** and **DP&L**, each non-employee Director received a retainer in RSUs on the date of the shareholders' annual meeting. The RSUs became non-forfeitable on April 15 of the following year. The RSUs accrued quarterly dividends in the form of additional RSUs. Upon vesting, the RSUs became exercisable and were distributed in **DPL** common stock, unless the Director chose to defer receipt of the shares until a later date. The RSUs were valued at the closing stock price on the day prior to the grant and the compensation expense was recognized evenly over the vesting period.

At the Merger date, vesting for the remaining non-vested RSUs was accelerated and all vested RSUs (current and prior years) were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

The following table reflects information about RSU activity (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Restricted stock units:		
Outstanding at beginning of period	16,320	20,712
Granted	14,392	15,752
Dividends accrued	3,307	2,484
Vested and exercised	(34,019)	(2,618
Vested, exercised and deferred	-	(20,010
Forfeited	-	-
Outstanding at end of period	-	16,320
Exercisable at end of period	-	-

The following table reflects information about non-employee Director RSU activity during the period (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

$ in millions	Years ended December 31, 2011	2010
Weighted-average grant date fair value of non-employee Director RSUs granted during the period	0.5	0.5
Intrinsic value of non-employee Director RSUs exercised during the period	1.0	0.5
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	1.0	0.6
Unrecognized compensation expense	-	0.1
Weighted-average period to recognize compensation expense (in years)	-	0.3

Management Performance Shares

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

At the Merger date, vesting for all non-vested management performance shares was accelerated; some of the awards vested at target shares and other awards vested at a pro rata share of target. All vested shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger agreement.

Summarized management performance share activity was as follows (note that there is no management performance share activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Management performance shares:		
Outstanding at beginning of period	104,124	84,241
Granted	49,510	37,48C
Expired	(31,081)	-
Exercised	(111,289)	-
Forfeited	(11,264)	(17,597
Outstanding at end of period	-	104,124
Exercisable at end of period	-	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:

	Years ended December 31,	
$ in millions	2011	2010
Expected volatility	24.0%	24.3%
Weighted-average expected volatility	24.0%	24.3%
Expected life (years)	3.0	3.0
Expected dividends	5.0%	4.5%
Weighted-average expected dividends	5.0%	4.5%
Risk-free interest rate	1.2%	1.4%

The following table reflects information about management performance share activity during the period (note that there is no management performance share activity after November 27, 2011 as a result of the Merger):

	Years ended December 31,	
$ in millions	2011	2010
Weighted-average grant date fair value of management performance shares granted during the period	1.3	0.9
Intrinsic value of management performance shares exercised	3.3	-

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	2.7	0.9
Unrecognized compensation expense	-	0.9
Weighted-average period to recognize compensation expense (in years)	-	1.7

12. Redeemable Preferred Stock

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,058 were outstanding as of December 31, 2012. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2012. The table below details the preferred shares outstanding at December 31, 2012 and 2011:

		December 31, 2012 and 2011		Par Value ($ in millions)	
$ in millions except per share amounts	Preferred Stock Rate	Redemption price ($ per share)	Shares Outstanding	December 31, 2012	December 31, 2011
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	65,380	6.6	6.6
Total			228,058	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, 2012, **DP&L's** retained earnings of $534.2 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.

13. Common Shareholders' Equity

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 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.

14. 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 December 31, 2012, **DP&L** could be responsible for the repayment of 4.9%, or $78.2 million, of a $1,596.5 million debt obligation comprised of both fixed and variable rate securities with maturities between 2013 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2012, 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, 2012, these include:

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DP&L:					
Long-term debt	903.2	570.4	0.3	0.2	332.3
Interest payments	361.9	34.0	31.6	31.6	264.7
Pension and postretirement payments	256.2	24.6	50.3	51.1	130.2
Operating leases	1.0	0.4	0.6	-	-
Coal contracts [a]	586.4	227.6	150.6	138.8	69.4
Limestone contracts [a]	26.8	5.4	10.7	10.7	-
Purchase orders and other contractual obligations	55.9	34.6	10.9	10.4	-
Reserve for uncertain tax positions	18.3	18.3	-	-	-
Total contractual obligations	2,209.7	915.3	255.0	242.8	796.6

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

Long-term debt:
DP&L's long-term debt as of December 31, 2012, 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 6 for additional information.

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, 2012.

Pension and postretirement payments:
As of December 31, 2012, **DP&L** had estimated future benefit payments as outlined in Note 8. These estimated future benefit payments are projected through 2022.

Capital leases:
As of December 31, 2012, **DP&L** had two immaterial capital leases that expire in 2013 and 2014.

Operating leases:
As of December 31, 2012, **DP&L** had several immaterial operating leases with various terms and expiration dates.

Coal contracts:
DP&L has entered into various long-term coal contracts to supply the coal requirements for the generating stations it operates. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Limestone contracts:
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, 2012, **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:
As of December 31, 2012, **DP&L** had $18.3 million in uncertain tax positions which are expected to be resolved within the next year.

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 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 Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 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. We have estimated liabilities of approximately $3.6 million for environmental matters. We evaluate the potential liability related to probable losses arising from environmental matters 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 electric generating stations. Some of these matters could have material adverse impacts on the operation of the stations; especially the stations that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired generating units 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 commonly owned Unit 6, in December 2014. This was followed by a notification by the joint owners of Beckjord 6 to PJM, dated April 12, 2012, of a planned June 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.

DP&L has informed PJM that Hutchings Unit 4 has incurred damage to a rotor and will be deactivated June 1, 2014. In addition, **DP&L** has notified PJM that the remaining Hutchings units 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 how much of a pollutant 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 electric generating stations 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 stations. Once fully implemented in 2014, the rule would have required 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, we believe companies will have three years or more before they 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. On January 24, 2013, the D.C. Circuit Court denied this petition for rehearing en banc of the D.C. Circuit Court's August 2012 decision to vacate CSAPR. Therefore, CAIR remains in effect. If CSAPR were to be reinstated in its current form, we do not expect any material capital costs for **DP&L's** stations, 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 replacement interstate transport 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. Our 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 could have a material adverse effect on our results of operations and result in material compliance costs.

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. On December 21, 2012, the Administrator of USEPA signed the final rule, which will be followed by publication in the Federal Register. Compliance costs are not expected to be material to **DP&L's** operations.

On May 3, 2010, the National Emissions Standards for Hazardous Air Pollutants for compression ignition (CI) reciprocating internal combustion engines (RICE) became effective. 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. **DP&L** expects to meet this deadline and expects the compliance costs to be immaterial.

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 December 31, 2012, USEPA redesignated Adams County, where Stuart and Killen are located, to attainment. This status may be temporary, as on December 14, 2012, the USEPA tightened the PM 2.5 standard to 12.0 micrograms per cubic meter. This will begin a process of redesignations during 2014. We cannot predict the effect the revisions to the PM 2.5 standard will have on **DP&L's** financial condition or results of operations.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. On September 2, 2011, the USEPA decided to postpone their revisiting of this standard until 2013. **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.

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. Numerous units owned and operated by us will be affected by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

Carbon Dioxide 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 electric generating stations. We cannot predict the effect of these standards, if any, on **DP&L's** operations.

Approximately 97% 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**.

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

Litigation Involving Co-Owned Units

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 stations 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 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 Units

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 Ohio Power (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 units.

In June 2000, the USEPA issued an NOV to the **DP&L**-operated Stuart generating station (co-owned by **DP&L**, Duke Energy, and Ohio Power) for alleged violations of the CAA. The NOV contained allegations 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.

<u>Notices of Violation Involving Wholly-Owned Stations</u>

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 two projects described in the NOV were modifications subject to NSR. **DP&L** is engaged in discussions with the USEPA and Justice Department 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

<u>Clean Water Act – Regulation of Water Intake</u>

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 required 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, which were published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. In July 2012, USEPA announced that the final rules will be released in June 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. The 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. In November 2012, Ohio EPA issued another draft which included a compliance schedule for performing a study to justify an alternate thermal limitation and to which **DP&L** submitted comments. In December 2012, the USEPA formally withdrew their objection to the permit. On January 7, 2013, Ohio EPA issued a final permit. On February 1, 2013, **DP&L** appealed various aspects of the final permit to the Environmental Review Appeals Commission. 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. Subsequent to the information collection effort, it was anticipated that the USEPA would release a proposed rule by mid-2012 with a final regulation in place by early 2014. In December 2012, USEPA announced that the proposed rule would be released by April 19, 2013 with a deadline for a final rule on May 22, 2014. At present, **DP&L** is unable to predict the impact this rulemaking will have on its operations.

In August 2012, **DP&L** submitted an application for the renewal of the Killen Station NPDES permit which expired in January 2013. At present, the outcome of this proceeding is not known.

In April 2012, **DP&L** received an NOV related to the construction of the Carter Hollow landfill at the 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 NOV. 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, was conducted in 2012 and may continue throughout 2013. In October 2012, **DP&L** received a request from PRP group's consultant to conduct additional soil and groundwater sampling on

DP&L's service center property. **DP&L** is complying with this sampling request. On February 8, 2013, the Court granted **DP&L's** motion for summary judgment on statute of limitations grounds with respect to claims seeking a contribution toward the costs that are expected to be incurred by PRP group in their performing a Remediation Investigation and Feasibility Study. The Court's ruling is likely to be appealed. **DP&L** is unable to predict the outcome of the appeal. Additionally, the Court's ruling does not address future litigation that may arise with respect to actual remediation costs. 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 seeking information from potentially affected parties on how it should proceed, the outcome may have a material effect on **DP&L**. While the USEPA has indicated that the official release date for a proposed rule is sometime in April 2013, it may be delayed until late 2013 or early 2014. 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 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 May 2012, we received a draft report on the inspection. **DP&L** submitted comments on the draft report in June 2012. **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. Litigation has been filed by several groups seeking a court-ordered deadline for the issuance of a final rule which USEPA has opposed. At present, the timing for a final rule regulating coal combustion byproducts cannot be determined. **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 its operations.

Notice of Violation Involving Co-Owned Units

On September 9, 2011, **DP&L** received an NOV from the USEPA with respect to its co-owned 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 National Pollutant Discharge Elimination System 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 stations 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 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 $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; at December 31, 2012, there is no remaining balance in other deferred credits related to SECA.

15. 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 stations. 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 station of **DP&L**. This determination was based on the assessment of the stations' 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 stations, Conesville and Hutchings, were not recoverable. To measure the amount of impairment loss, management was required to determine the fair value of the two stations. 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 station, 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 station prior to the impairment was $97.5 million. Accordingly, the Conesville station 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 Station, 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 Station prior to the impairment was $8.3 million. Accordingly, the Hutchings Station was considered impaired and $8.3 million of impairment expense was recognized in the third quarter of 2012.

16. Selected Quarterly Information (Unaudited)

From 2012 onwards, quarterly information is no longer required.

$ in millions except per share amounts and common stock market price	For the 2011 quarters ended March 31	June 30	September 30	December 31
Revenues	449.8	397.0	452.5	378.4
Operating income	89.3	55.8	100.0	74.8
Net income	52.7	30.8	63.9	45.8
Earnings on common stock	52.5	30.6	63.7	45.5
Dividends paid on common stock to **DPL**	70.0	45.0	65.0	40.0

$ in millions except per share amounts and common stock market price	For the 2010 quarters ended March 31	June 30	September 30	December 31
Revenues	423.8	412.6	472.4	430.0
Operating income	118.4	97.0	131.9	102.9
Net income	72.1	59.4	83.2	63.0
Earnings on common stock	71.9	59.2	83.0	62.7
Dividends paid on common stock to **DPL**	90.0	60.0	-	150.0

Item 9 – Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

On November 28, 2011, **DPL** changed auditors to Ernst & Young LLP. **DP&L** continued to use KPMG LLP through December 31, 2011 but changed auditors to Ernst & Young LLP effective January 1, 2012. Ernst & Young LLP are the auditors of AES. These changes were not a result of any disagreement with KPMG LLP.

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 quarter ended December 31, 2012 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, 2012.

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, 2012.

Item 9B – Other Information

None.

PART III

Item 10 – Directors, Executive Officers and Corporate Governance

Not applicable pursuant to General Instruction I of the Form 10-K.

Item 11 – Executive Compensation

Not applicable pursuant to General Instruction I of the Form 10-K.

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

Not applicable pursuant to General Instruction I of the Form 10-K.

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

Not applicable pursuant to General Instruction I of the Form 10-K.

Item 14 – Principal Accountant Fees and Services

Accountant Fees and Services

The following table presents the aggregate fees billed for professional services rendered to **DPL** and **DP&L** by Ernst & Young LLP and KPMG LLP for 2012 and 2011. As noted in Item 9, KPMG LLP was replaced as our principal accountant by Ernst & Young LLP on January 1, 2012. Other than as set forth below, no professional services were rendered or fees billed by Ernst & Young LLP and KPMG LLP during 2012 and 2011.

	2012 fees billed	2011 fees billed *(DPL only)*
Ernst & Young		
Audit fees [(a)]	1,464,000	550,000
Audit-related Fees [(b)]	823,859	-
Tax Fees [(c)]	-	-
All Other Fees [(d)]	-	-
Total	2,287,859	550,000

KPMG LLP	2012 fees billed	2011 fees billed
Audit fees [(a)]	N/A	2,080,046
Audit-related Fees [(b)]	N/A	41,000
Tax Fees [(c)]	N/A	4,000
All Other Fees [(d)]	N/A	12,000
Total	N/A	2,137,046

(a) Audit fees relate to professional services rendered for the audit of our annual financial statements and the reviews of our quarterly financial statements and other services that are normally provided in connection with regulatory filing or engagements.

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

(c) Tax fees consisted principally of tax compliance services.

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

The Boards of Directors of DPL Inc. and The Dayton Power and Light Company (collectively, the "Board") pre-approve all audit and permitted non-audit services, including engagement fees and terms for such services in accordance with Section 10A of the Securities Exchange Act of 1934, as amended. The Board will generally pre-

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approve a listing of specific services and categories of services, including audit, audit-related and other services, for the upcoming or current fiscal year, subject to a specified cost level. Any material service not included in the pre-approved list of services must be separately pre-approved by the Board. In addition, all audit and permissible non-audit services in excess of the pre-approved cost level, whether or not such services are included on the pre-approved list of services, must be separately pre-approved by the Board.

PART IV

Item 15 – Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. Financial Statements

ended December 31, 2012

DP&L – Notes to Financial Statements 161

2. Financial Statement Schedules

For each of the three years in the period ended December 31, 2012:

Schedule II – Valuation and Qualifying Accounts

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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.

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	DP&L	Exhibit Number	Exhibit	Location
X		2(a)	Agreement and Plan of Merger, dated as of April 19, 2011, by and among DPL Inc., The AES Corporation and Dolphin Sub, Inc.	Exhibit 2.1 to Report on Form 8-K filed April 20, 2011 (File No. 1-9052)
X		3(a)	Amended Articles of Incorporation of DPL Inc., as amended through January 6, 2012	Filed herewith as Exhibit 3(a)
X		3(b)	Amended Regulations of DPL Inc., as amended through November 28, 2011	Exhibit 3.2 to Report on Form 8-K filed November 28, 2011 (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 ende 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 or Form 10-K for the year ende December 31, 1998 (File No. 1-2385)
X	X	4(c)	Forty-Second Supplemental Indenture dated as of September 1, 2003, between	Exhibit 4(r) to Report on Form 10-K for the year ende

			The Dayton Power and Light Company and The Bank of New York, Trustee	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		4(e)	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

DPL	DP&L	Exhibit Number	Exhibit	Location
X		4(f)	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(g)	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	X	4(h)	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 ende December 31, 2009 (File No. 1-2385)
X	X	4(i)	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 ende December 31, 2008 (File No. 1-2385)
X		4(j)	Indenture, dated October 3, 2011, between Dolphin Subsidiary II, Inc. and Wells Fargo Bank, National Association	Exhibit 4.1 to Report on Form 8-K filed October 5, 2011 by The AES Corporatio (File No. 1-12291)
X		4(k)	Supplemental Indenture, dated as of November 28, 2011, between DPL Inc. and Wells Fargo Bank, National Association	Filed herewith as Exhibi 4(k)
X		4(l)	Registration Rights Agreement, dated October 3, 2011, between Dolphin Subsidiary II, Inc. and Merrill Lynch Pierce Fenner & Smith Incorporated and each of the initial purchasers named therein	Filed herewith as Exhibi 4(l)
X	X	10(a)	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,	Exhibit 10.1 to Form 8-K filed April 22, 2010 (File No. 1-2385)

			and the lenders party to the Credit Agreement	
X	X	10(b)	Limited Consent and Waiver, dated as of May 24, 2011, to the 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, and the lenders party to the Credit Agreement	Exhibit 10.1 to Report on Form 8-K filed May 31, 2011 (File No. 1-2385)
X	X	10(c)	First Amendment Agreement, dated as of November 18, 2011, to the 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, and the lender party to the Credit Agreement	Filed herewith as Exhibit 10(c)

DPL	DP&L	Exhibit Number	Exhibit	Location
X		10(d)	Credit Agreement, dated as of August 24, 2011, among DPL Inc., PNC Bank, National Association, as Administrative Agent, Bank of America, N.A., Fifth Third Bank and U.S. Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the lenders party to the Credit Agreement	Exhibit 10(b) to Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-9052)
X		10(e)	Credit Agreement, dated as of August 24, 2011, among DPL Inc., U.S. Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, Bank of America, N.A., Fifth Third Bank and PNC Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the lenders party to the Credit Agreement	Exhibit 10(b) to Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-9052)
X	X	10(f)	Credit Agreement, dated as of August 24, 2011, among The Dayton Power and Light Company, Fifth Third Bank, as Administrative Agent, Swing Line Lender and an L/C Issuer, Bank of America, N.A., U.S. Bank, National Association and PNC Bank, National Association, as Co-Syndication Agents,	Exhibit 10(b) to Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-2385)

			Bank of America, N.A., as Documentation Agent, and the lenders party to the Credit Agreement	
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)

DPL	DP&L	Exhibit Number	Exhibit	Location
	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

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.

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 have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized

DPL Inc.

February 26, 2013 By: /s/ Philip R. Herrington

(Philip R. Herrington)
President and Chief Executive Officer
(principal executive officer)

The Dayton Power and Light Company

February 26, 2013 By: /s/ Philip R. Herrington

(Philip R. Herrington)
President and Chief Executive Officer
(principal executive officer)

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 in the capacities and on the dates indicated.

/s/ Elizabeth Hackenson (Elizabeth Hackenson)	Director	February 26, 2013
/s/ Philip R. Herrington (Philip R. Herrington)	Director, President and Chief Executive Officer (principal executive officer)	February 26, 2013
/s/ Willard C. Hoagland, III (Willard C. Hoagland, III)	Director	February 26, 2013
/s/ Brian A. Miller (Brian A. Miller)	Director	February 26, 2013
/s/ Thomas M. O'Flynn (Thomas M. O'Flynn)	Director	February 26, 2013
(Mary Stawikey)	Director	February 26, 2013
/s/ Andrew M. Vesey (Andrew M. Vesey)	Director and Chairman	February 26, 2013
/s/ Craig L. Jackson (Craig L. Jackson)	Senior Vice President, Chief Financial Officer (principal financial officer)	February 26, 2013
/s/ Gregory S. Campbell (Gregory S. Campbell)	Vice President and Controller (principal accounting officer)	February 26, 2013

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

/s/ Willard C. Hoagland, III (Willard C. Hoagland, III)	Director	February 26, 2013
/s/ Elizabeth Hackenson (Elizabeth Hackenson)	Director	February 26, 2013
/s/ Philip R. Herrington (Philip R. Herrington)	Director, President and Chief Executive Officer (principal executive officer)	February 26, 2013
/s/ Vincent W. Mathis (Vincent W. Mathis)	Director	February 26, 2013
/s/ Brian A. Miller (Brian A. Miller)	Director	February 26, 2013
/s/ Britaldo Pedrosa Soares (Britaldo Pedrosa Soares)	Director	February 26, 2013
/s/ Andrew M. Vesey (Andrew M. Vesey)	Director and Chairman	February 26, 2013
/s/ Thomas M. O'Flynn (Thomas M. O'Flynn)	Director	February 26, 2013
/s/ Kenneth J. Zagzebski	Director	February 26,

(Kenneth J. Zagzebski)		2013
/s/ Craig L. Jackson (Craig L. Jackson)	Senior Vice President, Chief Financial Officer (principal financial officer)	February 26, 2013
/s/ Gregory S. Campbell (Gregory S. Campbell)	Vice President and Controller (principal accounting officer)	February 26, 2013

Schedule II

DPL Inc.
VALUATION AND QUALIFYING ACCOUNTS
For the years ended Year ended December 31, 2010 - 2012

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions [a]	Balance at End of Perioc
Successor				
Year ended December 31, 2012				
Deducted from accounts receivable -				
Provision for uncollectible accounts	1,136	5,902	5,954	1,084
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	6,702	6,747	1,100	12,349
For the period November 28, 2011 through December 31, 2011				
Deducted from accounts receivable -				
Provision for uncollectible accounts	1,062	643	569	1,136
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	7,086	349	733	6,702
Predecessor				
For the period January 1, 2011				

through November 27, 2011 Deducted from accounts receivable - Provision for uncollectible accounts	871	5,716	5,525	1,062
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	13,079	2,705	8,698	7,086
Year ended December 31, 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

[(a)] 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 Year ended December 31, 2010 - 2012

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions [(a)]	Balance at End of Period
Year ended December 31, 2012 Deducted from accounts receivable - Provision for uncollectible accounts	941	5,393	5,411	923
Year ended December 31, 2011 Deducted from accounts receivable - Provision for uncollectible accounts	832	6,137	6,028	941
Year ended December 31, 2010 Deducted from accounts receivable - Provision for uncollectible accounts	1,101	4,100	4,369	832

[a] Amounts written off, net of recoveries of accounts previously written off.

XBRL-only content section

DPL Statement of OCI

Change in available-for-sale securities tax effect	Decem ber 31, 2012	Decem ber 31, 2011	Novem ber 27, 2011	Decen ber 31, 2010
	(0.2)	-	-	(0.2

Reclassification to earnings - available for sale	Decem ber 31, 2012	Decem ber 31, 2011	Novem ber 27, 2011	Decen ber 31, 2010
	-	-	-	-

Change in derivative fair value tax effect - derivative activity	Decem ber 31, 2012	Decem ber 31, 2011	Novem ber 27, 2011	Decen ber 31, 2010
	1.4	0.3	31.2	(6.6

Reclassification of earnings tax effect - derivative activity	Decem ber 31, 2012	Decem ber 31, 2011	Novem ber 27, 2011	Decen ber 31, 2010
	0.4	-	(0.3)	2.C

Prior service cost - pension	Decem ber 31, 2012	Decem ber 31, 2011	Novem ber 27, 2011	Decen ber 31, 2010
	-	0.2	-	(3.7

Net loss - pension	Decem ber 31, 2012	Decem ber 31, 2011	Novem ber 27, 2011	Decen ber 31, 2010
	1.0	(0.2)	(0.7)	4.C

Reclassification to earnings tax effect - pension	Decem ber 31, 2012	Decem ber 31, 2011	Novem ber 27, 2011	Decen ber 31, 2010
	-	-	1.5	(1.3

DP&L Statement of OCI

Change in available-for-sale securities tax effect	Decemb er 31, 2012	Decemb er 31, 2011	Decemt er 31, 2010
	(0.2)	4.3	0.6

Reclassification to earnings tax effect - available for sale	Decemb er 31, 2012	Decemb er 31, 2011	Decemt er 31, 2010
	-	-	-

Change in derivative fair value tax effect - derivative activity	Decemb er 31, 2012	Decemb er 31, 2011	Decemt er 31, 2010
	1.6	0.5	0.2

Reclassification of earnings tax effect - derivative activity	Decemb er 31, 2012	Decemb er 31, 2011	Decemt er 31, 2010
	0.5	0.1	(0.5

Prior service cost tax effect - pension	Decemb er 31, 2012	Decemb er 31, 2011	Decemt er 31, 2010
	(0.5)	(0.4)	(0.4

Net loss tax effect - pension	Decemb er 31, 2012	Decemb er 31, 2011	Decemt er 31, 2010
	0.8	5.4	(0.1

	December 31, 2012	December 31, 2011	December 31, 2010
Reclassification to earnings tax effect - pension	(1.5)	(1.5)	(0.5

DPL Debt Parentheticals

Long-term

Caption parentheticals					
First mortgage bonds maturing in	October 2013	5.125%			
Pollution control series maturing in	January 2028	4.7%			
Pollution control series maturing in	January 2034	4.8%			
Pollution control series maturing in	September 2036	4.8%			
Pollution control series maturing in	November 2040	0.04%	0.26%	0.06%	0.32%
U.S. Government note maturing in	February 2061	4.20%			
Bank term loan-maturing in	August 2014	1.48%	4.25%	2.22%	2.47%
Senior unsecured bonds maturing	October 2016	6.50%			
Senior unsecured bonds maturing	October 2021	7.25%			
Note to DPL Capital Trust II maturing in	September 2031	8.125%			

Current

Caption parentheticals		
First mortgage bonds maturing in	October 2013	5.125%
U.S. Government note maturing in	February 2061	4.20%

DP&L Debt Parentheticals

Long-term

Caption parentheticals

First mortgage bonds maturing in	October 2013	5.125%			
Pollution control series maturing in	January 2028	4.7%			
Pollution control series maturing in	January 2034	4.8%			
Pollution control series maturing in	September 2036	4.8%			
Pollution control series maturing in	November 2040	0.04%	0.26%	0.06%	0.32%
U.S. Government note maturing in	February 2061	4.2%			

Current

Caption parentheticals		
U.S. Government note maturing in	February 2061	4.2%