BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 15-1830-EL-AIR

CASE NO. 15-1831-EL-AAM

CASE NO. 15-1832-EL-ATA

2015 DISTRIBUTION BASE RATE CASE

BOOK I – APPLICATION AND SUPPLEMENTAL

VOLUME 5 OF 14

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DOCKETING DIVISION
Public Utilities Commission of Ohio

Dayton Power and Light Company

DP&L Case No. 15-1830-EL-AIR

Standard Filing Requirements for Rate Increases

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		OAC 4901-7 Appendix A, Chapter II, (B) Supplemental Filing Requirements		
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1	1	Appendix A, Chapter II, (B)(2)(a)-(c) Appendix A, Chapter II, (B)(3)(a)-(d)	S-2	Most recent 5 year financial forecast and support for the underlying assumptions.
1	1	Appendix A ,Chapter II, (B)(7)	S-3	A proposed notice for newspaper publication.
1	1	Appendix A, Chapter II, (B)(8)	S-4.1	An executive summary of applicant utility's corporate process.
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		OAC 4901-7 Appendix A, Chapter II, (C) Supplemental Information Provided at Filing		
1	3	Appendix A, Chapter II, (C)(1)	Supplemental	The most recent Federal Energy Regulatory Commission's ("FERC") audit report.
1	3	Appendix A, Chapter II, (C)(2)	Supplemental	Prospectuses of current stock and/or bond offering of the applicant, and/or of parent company.
1	4-8	Appendix A, Chapter II, (C)(3)	Supplemental	Annual reports to shareholders of the applicant, and/or parent company for the most recent five years and the most recent statistical supplement.
1	9-12	Appendix A, Chapter II, (C)(4)	Supplemental	The most recent SEC Form 10-K, 10-Q, and 8-K of the applicant, and/or parent company.
1	13	Appendix A, Chapter II, (C)(5)	Supplemental	Working papers supporting the schedules.
1	14	Appendix A, Chapter II, (C)(6)	Supplemental	Worksheet showing monthly test year data by FERC account.
1	14	Appendix A, Chapter II, (C)(7)	Supplemental	CWIP included in the prior case.
1	14	Appendix A, Chapter II, (C)(8)	Supplemental	Copy of latest certificate of valuation from department of taxation.
1	14	Appendix A, Chapter II, (C)(9)	Supplemental	Monthly sales for the test year by rate schedule classification and/or customer classes.
1	14	Appendix A, Chapter II, (C)(10)	Supplemental	Written summary explaining the forecasting method used by the utility as related to test year data.
1	14	Appendix A, Chapter II, (C)(11)	Supplemental	Explanation of computation of materials and supplies.
1	14	Appendix A, Chapter II, (C)(12)	Supplemental	Depreciation expense related to specific plant accounts.
1	14	Appendix A, Chapter II, (C)(13)	Supplemental	Federal income tax information.
1	14	Appendix A, Chapter II, (C)(14)	Supplemental	Other rate base items and detailed information.
1	14	Appendix A, Chapter II, (C)(15)	Supplemental	Copy of all advertisements in the test year.
1	14	Appendix A, Chapter II, (C)(16)	Supplemental	Plant in service data from the last date certain to the date certain in the current case.
1	14	Appendix A, Chapter II, (C)(17)	Supplemental	Depreciation study showing depreciation reserves allocated to accounts.
1	14	Appendix A, Chapter II, (C)(18)	Supplemental	Depreciation study.
1	14	Appendix A, Chapter II, (C)(19)	Supplemental	Depreciation reserve data from the last date certain to the date certain in the current case.
1	14	Appendix A, Chapter II, (C)(20)	Supplemental	Construction project details for projects that are at least seventy-five percent complete.
1	14	Appendix A, Chapter II, (C)(21)	Supplemental	Surviving dollars by vintage year of placement (original cost data as of date certain for each individual plant account).
1	14	Appendix A, Chapter II, (C)(22)	Supplemental	Test year and two most recent calendar years' employee levels by month.

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended **December 31, 2013**

OR

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

For the transition period from ____________ to ____________

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

Securities registered pursuant to Section 12(b) of the Act: **None**

Indicate by check mark if each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

DPL Inc.	Yes ☐	No ☒
The Dayton Power and Light Company	Yes ☐	No ☒

Indicate by check mark if each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

DPL Inc.	Yes ☐	No ☒
The Dayton Power and Light Company	Yes ☐	No ☒

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

DPL Inc.	Yes ☐	No ☒
The Dayton Power and Light Company	Yes ☐	No ☒

Registrants are voluntary filers that have filed all applicable reports under Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months.

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

DPL Inc.	Yes ☒	No ☐
The Dayton Power and Light Company	Yes ☒	No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

DPL Inc.	☒
The Dayton Power and Light Company	☒

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

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
DPL Inc.	☐	☐	☒	☐
The Dayton Power and Light Company	☐	☐	☒	☐

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

DPL Inc.	Yes ☐	No ☒
The Dayton Power and Light Company	Yes ☐	No ☒

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

As of December 31, 2013, each registrant had the following shares of common stock outstanding:

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

Documents incorporated by reference: **None**

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

THE REGISTRANTS MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I(1)(a) AND (b) OF FORM 10-K AND ARE THEREFORE FILING THIS FORM WITH THE REDUCED DISCLOSURE FORMAT.

DPL Inc. and The Dayton Power and Light Company

Index to Annual Report on Form 10-K
Fiscal Year Ended December 31, 2013

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AEP Generation	AEP Generation Resources, Inc., a subsidiary of American Electric Power Company, Inc. ("AEP"). Columbus Southern Power Company merged into the Ohio Power Company, another subsidiary of AEP, effective December 31, 2011. The Ohio Power generating assets (including jointly-owned units) were transferred into this new AEP subsidiary, effective January 1, 2014.
AES	The AES Corporation, a global power company, the ultimate parent company of DPL
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
BTU	British Thermal Units
CFTC	Commodity Futures Trading Commission
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCEM	Customer Conservation and Energy Management
CO_2	Carbon Dioxide
ComEd	Commonwealth Edison
CRES	Competitive Retail Electric Service
CSAPR	Cross-State Air Pollution Rule
Dark spread	A common metric used to estimate returns over fuel costs of coal-fired electric generating units
DPL	DPL Inc.
DPLE	DPL Energy, LLC, a wholly-owned subsidiary of DPL that owns and operates peaking generation facilities from which it makes wholesale sales
DPLER	DPL Energy Resources, Inc., a wholly-owned subsidiary of DPL which sells competitive electric energy and other energy services
DP&L	The Dayton Power and Light Company, the principal subsidiary of DPL and a public utility which sells electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. DP&L is wholly-owned by DPL
Duke Energy	Affiliates of Duke Energy with which DP&L co-owns electric generating units in Ohio (Duke Energy Ohio, Inc.) and Kentucky (Duke Energy Kentucky, Inc.)
EBITDA	Earnings before interest, taxes, depreciation and amortization
EGU	Electric generating unit
EIR	Environmental Investment Rider
EPS	Earnings Per Share
ESOP	Employee Stock Ownership Plan
ESP	The Electric Security Plan is a cost-based plan that a utility may file with the PUCO to establish SSO rates pursuant to Ohio law

Abbreviation or Acronym	Definition
2009 ESP Stipulation	A Stipulation and Recommendation filed with the PUCO on February 24, 2009 regarding DP&L's ESP filing pursuant to SB 221. The Stipulation was signed by the Staff of the PUCO, the OCC and various intervening parties. The PUCO approved the Stipulation on June 24, 2009.
FASB	Financial Accounting Standards Board
FASC	FASB Accounting Standards Codification
FASC 805	FASB Accounting Standards Codification 805, "Business Combinations"
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
First and Refunding Mortgage	DP&L's First and Refunding Mortgage, dated October 1, 1935, as amended, with the Bank of New York Mellon as Trustee
FTRs	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
kWh	Kilowatt hour
Master Trust	DP&L established a Master Trust to hold assets that could be used for the benefit of employees participating in employee benefit plans
MC Squared	MC Squared Energy Services, LLC, a retail electricity supplier wholly-owned by DPLER which was purchased by DPLER on February 28, 2011
Merger	The merger of DPL and Dolphin Sub, Inc. (a wholly-owned subsidiary of AES) in accordance with the terms of the Merger agreement. At the Merger date, Dolphin Sub, Inc. was merged into DPL, leaving DPL as the surviving company. As a result of the Merger, DPL became a wholly-owned subsidiary of AES.
Merger agreement	The Agreement and Plan of Merger dated April 19, 2011 among DPL, AES and Dolphin Sub, Inc., a wholly-owned subsidiary of AES, whereby AES agreed to acquire DPL for $30 per share in a cash transaction valued at approximately $3.5 billion plus the assumption of $1.2 billion of existing debt. Upon closing, DPL became a wholly-owned subsidiary of AES.
Merger date	November 28, 2011, the date of the closing of the merger of DPL and Dolphin Sub, Inc., a wholly-owned subsidiary of AES
MRO	Market Rate Option, a market-based plan that a utility may file with PUCO to establish SSO rates pursuant to Ohio law
MTM	Mark to Market
MVIC	Miami Valley Insurance Company, a wholly-owned insurance subsidiary of DPL that provides insurance services to DPL and its subsidiaries and, in some cases, insurance services to partner companies relative to jointly-owned facilities operated by DP&L
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
Non-bypassable	Charges that are assessed to all customers regardless of whom the customer selects to supply its retail electric service
NOV	Notice of Violation

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSR	New Source Review is a preconstruction permitting program regulating new or significantly modified sources of air pollution
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority
OCC	Ohio Consumers' Counsel
Ohio EPA	Ohio Environmental Protection Agency
OTC	Over the counter
OVEC	Ohio Valley Electric Corporation, an electric generating company in which DP&L holds a 4.9% equity interest
PJM	PJM Interconnection, LLC, an RTO
Predecessor	DPL prior to the Merger date
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
RPM	The Reliability Pricing Model is PJM's capacity construct. The purpose of RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of electric customers within the PJM footprint. Under the RPM construct, PJM procures capacity, through a multi-auction structure, on behalf of the load serving entities to satisfy the load obligations. There are three RPM auctions held for each Delivery Year (running from June 1 through May 31). The Base Residual Auction is held three years in advance of the Delivery Year and there is one Incremental Auction held in each of the subsequent three years. DP&L's capacity is located in the "rest of" RTO area of PJM.
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
SB 221	Ohio Senate Bill 221, an Ohio electric energy bill that was signed by the Governor on May 1, 2008 and went into effect July 31, 2008. This law required all Ohio distribution utilities to file either an ESP or MRO to be in effect January 1, 2009. The law also contains, among other things, annual targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SECA	Seams Elimination Charge Adjustment
SEET	Significantly Excessive Earnings Test
SERP	Supplemental Executive Retirement Plan
Service Company	AES US Services, LLC, the shared services affiliate providing accounting, finance, and other support services to AES' US SBU businesses
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
SSO	Standard Service Offer represents the retail transmission, distribution and generation services offered by the utility through regulated rates, authorized by the PUCO
SSR	Service Stability Rider
Successor	DPL after the Merger
TCRR	Transmission Cost Recovery Rider
TCRR-B	Transmission Cost Recovery Rider – Bypassable
TCRR-N	Transmission Cost Recovery Rider – Nonbypassable
USEPA	U.S. Environmental Protection Agency
USF	The Universal Service Fund (USF) is a statewide program which provides qualified low-income customers in Ohio with income-based bills and energy efficiency education programs
US SBU	AES' reporting unit covering the businesses in the United States, including DPL
VRDN	Variable Rate Demand Note

PART I

Item 1 – Business

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

FORWARD–LOOKING STATEMENTS

Certain statements contained in this report are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Matters discussed in this report that relate to events or developments that are expected to occur in the future, including management's expectations, strategic objectives, business prospects, anticipated economic performance and financial condition and other similar matters constitute forward-looking statements. Forward-looking statements are based on management's beliefs, assumptions and expectations of future economic performance, taking into account the information currently available to management. These statements are not statements of historical fact and are typically identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will" and similar expressions. Such forward-looking statements are subject to risks and uncertainties and investors are cautioned that outcomes and results may vary materially from those projected due to various factors beyond our control, including but not limited to:

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

and the risks and other factors discussed in this report and other **DPL** and **DP&L** filings with the SEC.

Forward-looking statements speak only as of the date of the document in which they are made. We disclaim any obligation or undertaking to provide any updates or revisions to any forward-looking statement to reflect any change in our expectations or any change in events, conditions or circumstances on which the forward-looking statement is based. If we do update one or more forward-looking statements, no inference should be made that we will make additional updates with respect to those or other forward-looking statements.

COMPANY WEBSITES

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

ORGANIZATION

DPL is a regional energy company incorporated in 1985 under the laws of Ohio. Our executive offices are located at 1065 Woodman Drive, Dayton, Ohio 45432 – telephone (937) 224-6000. **DPL** was acquired by The AES Corporation on November 28, 2011 and is a wholly-owned, indirect subsidiary of AES.

DP&L is a public utility incorporated in 1911 under the laws of Ohio. Beginning in 2001, Ohio law gave Ohio consumers the right to choose the electric generation supplier from whom they purchase retail generation service, however distribution and transmission retail service are still regulated. **DP&L** has the exclusive right to provide such service to its more than 515,000 customers located in West Central Ohio. Additionally, **DP&L** offers retail SSO electric service to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio and generates electricity at seven coal-fired power stations. Beginning in 2014, **DP&L** no longer provides 100% of the generation for its SSO customers. Principal industries located in **DP&L's** service territory include automotive, food processing, paper, plastic, manufacturing and defense. **DP&L's** sales reflect the general economic conditions, seasonal weather patterns of the area and the market price of electricity. **DP&L** sells any excess energy and capacity into the wholesale market. **DP&L** also sells electricity to DPLER, an affiliate, to satisfy the electric requirements of DPLER's retail customers.

DPLER sells competitive retail electric service, under contract, to residential, commercial, industrial and governmental customers. DPLER's operations include those of its wholly-owned subsidiary, MC Squared, which was purchased on February 28, 2011. DPLER has approximately 308,000 customers currently located throughout Ohio and Illinois. Approximately 130,000 of DPLER's customers are also electric distribution customers of **DP&L**. DPLER does not have any transmission or generation assets and all of DPLER's electric energy was purchased from **DP&L** or PJM to meet its sales obligations.

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

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

All of **DPL's** subsidiaries are wholly-owned. **DP&L** does not have any subsidiaries.

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 recoveries in customer rates relate to expected future costs.

DPL and its subsidiaries had 1,266 employees as of December 31, 2013. At that date, 1,218 of these employees were employed by **DP&L**. Approximately 59% of the employees of **DPL** and its subsidiaries are under a collective bargaining agreement which expires on October 31, 2014.

Effective December 22, 2013, AES US Services, LLC (the "Service Company") began providing services including accounting, legal, human resources, information technology and other services of a similar nature on behalf of the AES U.S. Strategic Business Unit ("U.S. SBU"). The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable distribution. This includes ensuring that the regulated businesses served, including **DP&L**, are not subsidizing costs incurred for the benefit of non-regulated businesses.

ELECTRIC OPERATIONS AND FUEL SUPPLY

2013 Summer Generating Capacity (in MW)

Summer Generating Capacity	Coal fired	Combustion Turbines, Diesel Units and Solar	Total
DPL	2,465	988	3,453
DP&L	2,465	432	2,897

DPL's present summer generating capacity, including peaking units, is 3,453 MW. Of this capacity, 2,465 MW, or 71%, is derived from coal-fired steam generating stations and the balance of 988 MW, or 29%, consists of combustion turbines, diesel peaking units and solar.

DP&L's present summer generating capacity, including peaking units, is 2,897 MW. Of this capacity, 2,465 MW, or 85%, is derived from coal-fired steam generating stations and the balance of 432 MW, or 15%, consists of combustion turbines, diesel peaking units and solar.

Our all-time net peak load was 3,270 MW, occurring August 8, 2007.

100% of **DP&L's** existing steam generating capacity is provided by generating units owned as tenants in common with Duke Energy and AEP Generation. As tenants in common, each company owns a specified share of each of these units, is entitled to its share of capacity and energy output and has a capital and operating cost responsibility proportionate to its ownership share. The coal-fired portion of **DP&L's** 100% owned steam generating station (Hutchings) was deactivated in September 2013. Additionally, **DP&L**, Duke Energy and AEP Generation own, as tenants in common, 880 circuit miles of 345,000-volt transmission lines. **DP&L** has several interconnections with other companies for the purchase, sale and interchange of electricity.

In 2013, we generated 99% of our electric output from coal-fired units and 1% from solar, oil and natural gas-fired units.

The following table sets forth **DP&L's** and DPLE's generating stations and, where indicated, those stations which **DP&L** owns as tenants in common:

Station	Ownership (a)	Operating Company	Location	Approximate Summer MW Rating: DP&L Portion (b)	Approximate Summer MW Rating: Total
Coal Units					
Hutchings	W	DP&L	Miamisburg, OH	-	-
Killen	C	DP&L	Wrightsville, OH	402	600
Stuart	C	DP&L	Aberdeen, OH	808	2,308
Conesville-Unit 4	C	AEP Generation	Conesville, OH	129	780
Beckjord-Unit 6	C	Duke Energy	New Richmond, OH	207	414
Miami Fort-Units 7 & 8	C	Duke Energy	North Bend, OH	368	1,020
East Bend-Unit 2	C	Duke Energy	Rabbit Hash, KY	186	600
Zimmer	C	Duke Energy	Moscow, OH	365	1,300
Solar, Combustion Turbines or Diesel					
Hutchings	W	DP&L	Miamisburg, OH	25	25
Yankee Street	W	DP&L	Centerville, OH	101	101
Yankee Solar	W	DP&L	Centerville, OH	1	1
Monument	W	DP&L	Dayton, OH	12	12
Tait Diesels	W	DP&L	Dayton, OH	10	10
Sidney	W	DP&L	Sidney, OH	12	12
Tait Units 1 - 3	W	DP&L	Moraine, OH	256	256
Killen	C	DP&L	Wrightsville, OH	12	18
Stuart	C	DP&L	Aberdeen, OH	3	10
Montpelier Units 1 - 4	W	DPLE	Poneto, IN	236	236
Tait Units 4 - 7	W	DPLE	Moraine, OH	320	320
Total approximate summer generating capacity				3,453	8,023

(a) W = Wholly-owned C = Commonly-owned
(b) **DP&L** portion of commonly-owned generating stations

As part of a settlement with the USEPA, **DP&L** signed a Consent Agreement and Final Order (CAFO) that was filed on September 26, 2013 and an Administrative Consent Order. Together, these two agreements resolved the opacity and particulate emissions NOV at the Hutchings Station and required that all six coal-fired units at Hutchings cease operating on coal by September 30, 2013, and included an immaterial penalty and the completion of a Supplemental Environmental Project of $0.2 million within one year. The units were disabled for coal operations prior to September 30, 2013. The removal of this capacity has been reflected in the table above.

In addition to the above, **DP&L** also owns a 4.9% equity ownership interest in OVEC, an electric generating company. OVEC has two electric generating stations located in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of 2,109 MW. **DP&L's** share of this generation capacity is 103 MW.

We have substantially all of the total expected coal volume needed to meet our retail and wholesale sales requirements for 2014 under contract. 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/forced outages and generation station mix. Due to the installation of emission control equipment at certain commonly-owned units and barring any changes in the regulatory environment in which we operate, we expect to have balanced positions for SO_2, NO_x and renewable energy credits for 2014.

The gross average cost of fuel consumed per kWh was as follows:

	Average cost of Fuel Consumed (cents per kWh)		
	2013	2012	2011
DPL	**2.43**	2.75	2.76
DP&L	**2.40**	2.72	2.71

SEASONALITY

The power generation and delivery business is seasonal and weather patterns have a material effect on operating performance. In the region we serve, demand for electricity is generally greater in the summer months associated with cooling and in the winter months associated with heating compared to other times of the year. Unusually mild summers and winters could have an adverse effect on our results of operations, financial condition and cash flows.

RATE REGULATION AND GOVERNMENT LEGISLATION

DP&L's sales to SSO retail customers are subject to rate regulation by the PUCO. In addition, certain of **DP&L's** recoverable costs are considered to be non-bypassable and are therefore assessed to all **DP&L** retail customers, under the regulatory authority of the PUCO, regardless of whom the customer selects to supply its retail electric service. **DP&L's** transmission rates and wholesale electric rates to municipal corporations, rural electric co-operatives and other distributors of electric energy are subject to regulation by the FERC under the Federal Power Act.

Ohio law establishes the process for determining SSO and non-bypassable rates charged by public utilities. Regulation of retail rates encompasses the timing of applications, the effective date of rate increases, the market price of power, the cost basis upon which the rates are set and other related matters. Ohio law also established the Office of the OCC, which has the authority to represent residential consumers in state and federal judicial and administrative rate proceedings.

Ohio legislation extends the jurisdiction of the PUCO to the records and accounts of certain public utility holding company systems, including **DPL**. The legislation extends the PUCO's supervisory powers to a holding company system's general condition and capitalization, among other matters, to the extent that such matters relate to the costs associated with the provision of public utility service. Based on existing PUCO and FERC authorization, regulatory assets and liabilities are recorded on the balance sheets. See Note 4 of Notes to **DPL's** Consolidated Financial Statements and Note 4 of Notes to **DP&L's** Financial Statements.

COMPETITION AND REGULATION

<u>Ohio Matters</u>

Ohio Retail Rates

The PUCO maintains jurisdiction over **DP&L's** delivery of electricity, SSO and other retail electric services.

On May 1, 2008, substitute SB 221, an Ohio electric energy bill, was signed by the Governor and went into effect July 31, 2008. This law required that all Ohio distribution utilities file either an ESP or MRO to establish rates for SSO service. Under the MRO, a periodic competitive bid process will set the retail generation price after the utility demonstrates that it can meet certain market criteria and bid requirements. Also, under this option, utilities that still own generation in the state are required to phase-in the MRO over a period of not less than five years. An ESP may allow for cost-based adjustments to the SSO for costs associated with environmental compliance; fuel and purchased power; construction of new or investment in specified generating facilities; and the provision of standby and default service, operating, maintenance, or other costs including taxes. As part of its ESP, a utility is permitted to file an infrastructure improvement plan that will specify the initiatives the utility will take to rebuild, upgrade, or replace its electric distribution system, including cost recovery mechanisms. Both the MRO and ESP option involve a SEET based on the earnings of comparable companies with similar business and financial risks.

On October 5, 2012, **DP&L** filed an ESP with the PUCO to establish SSO rates that were to be in effect starting January 2013. The plan was refiled on December 12, 2012 to correct for certain projected costs. The plan requested approval of a non-bypassable charge that was designed to recover $137.5 million per year for five years from all customers. The ESP proposed a three-year, five-month transition to market, whereby a wholesale competitive bidding structure would be phased in to supply generation service to customers located in **DP&L's** service territory that have not chosen an alternative generation supplier. An order was issued by the PUCO on September 4, 2013 and a correction to that order was issued on September 6, 2013 (ESP Order).

The ESP Order stated that **DP&L's** next ESP begins January 2014 and extends through May 31, 2017. The PUCO authorized **DP&L** to collect a non-bypassable Service Stability Rider (SSR) equal to $110 million per year for 2014 – 2016. **DP&L** has the opportunity to seek an additional $45.8 million through extension of the SSR through May 31, 2017, provided **DP&L** meets certain regulatory filing obligations, which include but are not limited to filing a plan by December 31, 2013 to separate the generation assets from the utility (as noted below, **DP&L** filed this on December 30, 2013) and filing a distribution rate case no later than July 1, 2014. The ESP Order also directs **DP&L** to divest its generation assets no later than May 31, 2017 and sets **DP&L's** SEET threshold at a 12% ROE. Beginning in 2014, **DP&L** is no longer permitted to supply 100% of the generation service for SSO customers. Instead, the PUCO directed **DP&L** to phase-in the competitive bidding structure with 10% of **DP&L's** SSO load sourced through the competitive bid starting in 2014, 40% in 2015, 70% in 2016, and 100% by June 1, 2017. The ESP Order approved **DP&L's** rate proposal to bifurcate its transmission charges into a non-bypassable component, TCRR-N, and a bypassable component, TCRR-B. The ESP order also required **DP&L** to establish a $2.0 million per year shareholder funded economic development fund. Applications for rehearing were filed on October 4, 2013 by **DP&L** and other parties and are currently pending PUCO action. On October 23, 2013, the PUCO issued an entry on rehearing denying applications for rehearing that related to the competitive bid. The PUCO reaffirmed its position that economic development load should be included in the competitive bid auction and that **DP&L** affiliates are permitted to bid in the auction.

In accordance with the ESP Order, on December 30, 2013, **DP&L** filed an application with the PUCO stating its plan to separate its generation assets to an affiliated entity on or before May 31, 2017.

SB 221 and the implementation rules contain targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards. If any targets are not met, compliance penalties will apply unless the PUCO makes certain findings that would excuse performance. The PUCO has found that **DP&L** met its renewable targets for compliance years 2008 – 2012. PUCO staff recommended that DPLER met its targets for compliance year 2012. Filing for compliance year 2013 will be made on or before April 15, 2014 and both **DP&L** and DPLER expect to be in full compliance with all renewable targets. **DP&L** plans to file its next energy efficiency portfolio plan in 2015. However, as the energy efficiency and alternative energy targets get increasingly larger over time, the costs of complying with SB 221 and the PUCO's implementing rules could have a material effect on our financial condition or results of operations.

The ESP Order also provided for the continuation of a fuel and purchased power recovery rider which began January 1, 2010. The fuel rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter: March 1, June 1, September 1 and December 1 each year. As part of the PUCO approval process, an outside auditor is hired each year to review fuel costs and the fuel procurement process. On June 12, 2013, we received a report from that external auditor recommending a pre-tax disallowance of $5.3 million of costs. Hearings in this case were held on December 9-10, 2013, and we expect an order in the case in the second quarter of 2014.

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. SB 221 includes a provision that would allow Ohio electric utilities to seek and obtain a reconcilable rider to recover RTO-related costs and credits. **DP&L's** TCRR and PJM RPM riders were initially approved in November 2009 to recover these costs. In accordance with the ESP Order, TCRR-N and TCRR-B will begin January 1, 2014. Both the TCRR-B and the RPM riders assign costs and revenues from PJM monthly bills to retail ratepayers based on the percentage of SSO retail customers' load and sales volumes to total retail load and total retail and wholesale volumes. Customer switching to CRES providers decreases **DP&L's** SSO retail customers' load and sales volumes. Therefore, increases in customer switching cause more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. RPM capacity costs and revenues are discussed further under "Regional Transmission Organizational Risks" in Item 1A – Risk Factors. **DP&L's** annual true-up of these riders was approved by the PUCO by Order dated April 24, 2013, and its 2014 filings will be made in the first and second quarters of 2014.

For calendar year 2012 **DP&L** was subject to a SEET threshold in which **DP&L** was required to apply general rules for calculating the earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings. Pursuant to an Order issued on February 13, 2014, **DP&L's** 2012 earnings were found to not be excessive. Through the ESP Order, the PUCO established **DP&L's** ROE SEET threshold at 12% beginning with 2013. In future years, the SEET could have a material effect on our results of operations, financial condition and cash flows.

On June 29, 2012, **DP&L** filed its application to establish reliability targets consistent with the most recent PUCO Electric Service and Safety Standards (ESSS). **DP&L** and PUCO Staff reached a settlement establishing new reliability targets in this case. The settlement was approved by the PUCO on October 4, 2013. According to the ESSS rules, all Ohio utilities are subject to financial penalties if the established targets are not met for two consecutive years. As of December 31, 2013, **DP&L** has not missed any of the reliability targets.

Ohio Competitive Considerations and Proceedings

Since January 2001, **DP&L's** electric customers have been permitted to choose their retail electric generation supplier. **DP&L** continues to have the exclusive right to provide delivery service in its state-certified territory and the obligation to supply and/or procure retail generation service to customers that do not choose an alternative supplier. The PUCO maintains jurisdiction over **DP&L's** delivery of electricity, SSO and other retail electric services.

Market prices for power, as well as government aggregation initiatives, have led and may continue to lead to the entrance of additional competitors in our service territory. As of December 31, 2013, there were thirty-six CRES providers registered in **DP&L's** service territory. DPLER, an affiliated company and one of the thirty-six registered CRES providers, has been marketing supply services to **DP&L** customers. During 2013, DPLER accounted for approximately 5,874 million kWh of the total 9,345 million kWh supplied by CRES providers within **DP&L's** service territory. Also during 2013, 87,951 customers with an annual energy usage of 3,471 million kWh were supplied by other CRES providers within **DP&L's** service territory. The volume supplied by DPLER represents approximately 42% of **DP&L's** total distribution sales volume during 2013. The reduction to gross margin in 2013 as a result of customers switching to DPLER and other CRES providers was approximately $248.4 million and $318.3 million, for **DPL** and **DP&L**, respectively. We currently cannot determine the extent to which customer switching to CRES providers will occur in the future and the effect this will have on us, but any additional switching could have a significant adverse effect on our future results of operations, financial condition and cash flows.

Several communities in **DP&L's** service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering retail generation service to their residents. To date, a number of communities have filed with the PUCO to initiate aggregation programs. If a number of the larger communities in **DP&L's** service area move forward with aggregation, it could have a material effect on our earnings.

DPLER began providing CRES services to business customers in Ohio who are not in **DP&L's** service territory in 2010 and to residential customers in 2012. Additionally, beginning in March 2011 with the purchase of MC Squared, DPLER services business and residential customers in northern Illinois. The incremental costs and revenues have not had a material effect on our results of operations, financial condition or cash flows.

Federal Matters

Like other electric utilities and energy marketers, **DP&L** and DPLE may sell or purchase electric products on the wholesale market. **DP&L** and DPLE compete with other generators, power marketers, privately and municipally-owned electric utilities and rural electric cooperatives when selling electricity. The ability of **DP&L** and DPLE to sell this electricity will depend not only on the performance of our generating units, but also on how **DP&L's** and DPLE's prices, terms and conditions compare to those of other suppliers.

As part of Ohio's electric deregulation law, all of the state's investor-owned utilities were required to join an RTO. In October 2004, **DP&L** successfully integrated its high-voltage transmission lines into the PJM RTO. The role of the RTO is to administer a competitive wholesale market for electricity and ensure reliability of the transmission grid. PJM ensures the reliability of the high-voltage electric power system serving more than 50 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, administers the world's largest competitive wholesale electricity market and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.

The PJM RPM capacity base residual auction for the 2016/17 period cleared at a price of $59/MW-day for our RTO area. The prices for the periods 2015/16, 2014/15 and 2013/14 were $136/MW-day, $126/MW-day and $28/MW-day, respectively, based on previous auctions. Future RPM auction results will be dependent not only on the overall supply and demand of generation and load, but may also be affected by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions. Increases in customer switching causes more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. We cannot predict the outcome of future auctions or customer switching but if the current auction price is not sustained, it could have a material adverse effect on our future results of operations, financial condition and cash flows.

NERC is a FERC-certified electric reliability organization responsible for developing and enforcing mandatory reliability standards, including Critical Infrastructure Protection (CIP) reliability standards, across eight reliability regions. In December 2012, **DP&L** underwent routine, scheduled NERC audits conducted by Reliability First Corporation (RFC), which focused on our performance in supporting PJM as our transmission operator, and our compliance with the CIP standards. **DP&L** was found 100% compliant in its performance in support of PJM. In the CIP audit, four minor documentation-related Possible Alleged Violations (PAVs) were identified, which were settled through a streamlined process, without any financial penalties. In November 2013, DPLE, **DPL's** merchant generation affiliate, underwent a routine, scheduled NERC audit, during which one minor PAV was identified; **DPL** anticipates that it will be settled through a streamlined process, with no financial penalty.

ENVIRONMENTAL MATTERS

DPL's and **DP&L's** facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. The environmental issues that may affect us include:

- The federal CAA and state laws and regulations (including State Implementation Plans) which require compliance, obtaining permits and reporting as to air emissions,
- Litigation with federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating stations require additional permitting or pollution control technology, or whether emissions from coal-fired generating stations cause or contribute to global climate changes,
- Rules and future rules issued by the USEPA and the Ohio EPA that require substantial reductions in SO_2, particulates, mercury, acid gases, NO_x, and other air emissions. **DP&L** has installed emission control technology and is taking other measures to comply with required and anticipated reductions,
- Rules and future rules issued by the USEPA and the Ohio EPA that require reporting and may require reductions of GHGs,
- Rules and future rules issued by the USEPA associated with the federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and
- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain waste. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion by-products. The USEPA has previously determined that fly ash and other coal combustion by-products are not hazardous waste subject to the Resource Conservation and Recovery Act (RCRA), but the USEPA is reconsidering that determination and planning to propose a new rule regulating coal combustion by-products. A change in determination or other additional regulation of fly ash or other coal combustion byproducts could significantly increase the costs of disposing of such by-products.

In addition to 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 our facilities to comply, or to determine compliance, with such regulations. We record liabilities for loss contingencies related to environmental matters when a loss is probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. Accordingly, we have accruals for loss contingencies of approximately $1.1 million for environmental matters. We also have a number of environmental matters for which we have not accrued loss contingencies because the risk of loss is not probable of a loss cannot be reasonably estimated, which are disclosed in the paragraphs below. We evaluate the potential liability related to 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 coal-fired generation units. Some of these matters could have material adverse impacts on the operation of the power stations; especially the stations that do not have SCR and FGD equipment installed to further control certain emissions. Currently, the coal-fired generation unit Beckjord Unit 6, in which **DP&L** has a 50% ownership interest, does not have such emission-control equipment installed. This unit is scheduled to be deactivated on June 1, 2015. **DPL** valued Beckjord Unit 6 at zero at the Merger date. **DP&L** is depreciating Unit 6 through December 2014 and does not believe that any additional accruals or impairment charges are needed as a result of this decision.

DP&L deactivated the coal units at Hutchings Station in September 2013 as part of a settlement with the USEPA discussed in more detail below.

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.

Clean Air Interstate Rule/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 NO_x emissions from existing power stations located in 27 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase began in 2009 and 2010 for NO_x and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions is scheduled 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 the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, CSAPR would have required significant reductions in SO_2 and NO_x emissions from covered sources, such as power stations in 28 eastern states. Once fully implemented in 2014, the rule would have required additional SO_2 emission reductions of 73% and additional NO_x 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. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that the 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 are to continue to serve as the governing program until the USEPA takes further action or the U.S. Congress intervenes. On October 5, 2012, the 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, which were denied. On June 24, 2013, the U.S. Supreme Court agreed to review the D.C. Circuit Court's decision to vacate CSAPR and heard oral arguments in the matter on December 10, 2013. Currently, 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 unit 6 will not operate on coal in 2015 due to implementation of the Mercury and Air Toxics Standards (MATS). If the USEPA issues 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.

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, on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Our affected EGUs must come into compliance with the new requirements by April 16, 2015, but may be granted an additional year to become compliant 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 January 31, 2013, the USEPA finalized a rule regulating emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers and process heaters at major and area source facilities. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulation contains emissions limitations, operating limitations and other requirements. **DP&L** expects to be in compliance with this rule and the costs are not currently expected to be material to **DP&L's** operations.

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, the USEPA redesignated Adams County, where Stuart and Killen are located, to attainment status. 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, including in counties where we have generating stations. 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.

The USEPA published the national ground level ozone standard on March 12, 2008, lowering the 8-hour level from 0.08 ppm to 0.075 ppm, which was upheld by the U.S. Circuit Court of Appeals in July 2013. No **DP&L** operations are currently located in non-attainment areas. The USEPA was expected to review the ozone NAAQS in 2013 but delayed such a review. Certain environmental groups have sued the USEPA in federal district court to force the USEPA to set a September 30, 2014 deadline for such review. It is generally expected that any revised standard resulting from such review would be more stringent than the current 0.075 ppm standard. In addition, in December 2013, eight northeastern states petitioned the USEPA to add nine upwind states, including Ohio, to the Ozone Transport Region, a group of states required to impose enhanced restrictions on ozone emissions. If the petition is granted, our facilities could be subject to such enhanced requirements.

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. Initial non-attainment designations were made July 25, 2013. Non-attainment areas will be required to meet the new standard by October 2018.

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 GHG 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, the 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, the USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under the USEPA's view, this is the final action that renders CO_2 and certain 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. Various industry groups and states petitioned the U.S. Supreme Court to review the D.C. Circuit Court's recent decision to uphold the USEPA's endangerment finding, its April 2010 GHG rule and the Tailoring Rule. On October 15, 2013, the U.S. Supreme Court agreed to review several related cases addressing the USEPA's authority to issue GHG Prevention of Significant Deterioration permits under Section 165 of the

CAA. We cannot predict the outcome of this review. 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 September 20, 2013, the USEPA proposed revised GHG New Source Performance Standards for new electric generating units (EGUs) under CAA subsection 111(b), which would require new EGUs to limit the amount of CO_2 emitted per megawatt-hour. The proposal anticipates that affected coal-fired units would need to rely upon partial implementation of carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. Furthermore, President Obama directed the USEPA to propose new standards, regulations, or guidelines, as appropriate, to address GHG emissions from existing EGUs under CAA subsection 111(d) by June 1, 2014, and finalize them by June 1, 2015. These latter rules may focus on energy efficiency improvements at power stations. We cannot predict the effect of these proposed or forthcoming standards on **DP&L's** operations.

Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 14 million tons annually. Further GHG legislation or regulation implemented 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 effect 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 NO_x, 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 AEP Generation (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. The Conesville complaint was resolved in 2007 as part of a larger settlement with the USEPA. Conesville was required to install FGD and SCR at the unit by the end of 2010, and those retrofits have been completed. The Beckjord complaint was also resolved through litigation. There were no penalties or settlement agreements that affected Beckjord 6.

In June 2000, the USEPA issued an NOV to the **DP&L**-operated Stuart generating station (co-owned by **DP&L**, Duke Energy and AEP Generation) 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, the 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. 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. As a result of the cessation of operations at the Hutchings Station discussed in the next paragraph, **DP&L** believes that the USEPA is unlikely to pursue the NSR complaint.

As part of a settlement with the USEPA, **DP&L** signed a Consent Agreement and Final Order (CAFO) that was filed on September 26, 2013 and an Administrative Consent Agreement. Together, these two agreements resolved the opacity and particulate emissions NOV at the Hutchings Station and required that all six coal-fired units at Hutchings cease operating on coal by September 30, 2013, and included an immaterial penalty and the completion of a Supplemental Environmental Project of $0.2 million within one year. The units were disabled for coal operations prior to September 30, 2013.

DP&L also resolved all issues associated with the Ohio EPA NOV through a settlement signed October 4, 2013. The settlement included the payment of an immaterial penalty.

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. The USEPA is required pursuant to a settlement agreement to issue a final rule by April 17, 2014. We do not yet know the impact the final rules will have on our operations.

Clean Water Act – Regulation of Water Discharge
In December 2006, **DP&L** submitted a renewal application for the Stuart Station NPDES permit that was due to expire on June 30, 2007. The Ohio EPA issued a revised draft permit that was received on November 12, 2008. In September 2010, the USEPA formally objected to the November 12, 2008 revised permit due to questions regarding the basis for the alternate thermal limitation. At **DP&L's** request, a public hearing was held on March 23, 2011, where **DP&L** presented its position on the issue and provided written comments. 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 did not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit would 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 required **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, the 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, the 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 appeal process, the effects could be material on **DP&L's** operations.

In September 2009, the USEPA announced that it would 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. The proposed rule was released on June 7, 2013, with a deadline for a final rule on May 22, 2014, though such final rule's issuance is expected to be delayed. 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 January 2014, **DP&L** submitted an application for the renewal of the Hutchings Station NPDES permit which expires in July 2014. 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** installed sedimentation ponds as part of the runoff control measures to address this issue and worked with the various agencies to resolve their concerns. **DP&L** signed an Administrative Order from the USEPA on May 30, 2013. A final Consent Agreement and Final Order was executed on July 8, 2013, and the previously issued permit was reinstated by the Corps on October 29, 2013.

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. 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 the PRP group in performing an RI/FS. That summary judgment ruling was appealed on March 4, 2013 and the appeal is pending. **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.

Beginning in mid-2012, the USEPA began investigating whether explosive or other dangerous conditions exist under structures located at or near the South Dayton Dump landfill site. In October 2012, **DP&L** received a request from the PRP group's consultant to conduct additional soil and groundwater sampling on **DP&L's** service center property. After informal discussions with the USEPA, **DP&L** complied with this sampling request and the sampling was conducted in February 2013. On February 28, 2013, the plaintiffs group referenced above entered into an Administrative Settlement Agreement Consent Order (ASACO) that establishes procedures for further sub-slab testing under structures at the South Dayton Dump landfill site and remediation of vapor intrusion issues relating to trichloroethylene (TCE), percholorethylene (PCE), and methane. On April 16, 2013, the plaintiffs group filed a new complaint in the United States District Court for the Southern District of Ohio against **DP&L** and 34 other defendants alleging that they share liability for these costs. **DP&L** has opposed the allegations that it bears any responsibility under the February 2013 ASACO and will actively oppose any attempt that the plaintiffs group may have to expand the scope of the new complaint to resurrect issues dismissed by the Court in February 2013 under the first complaint. A motion to dismiss portions of this second complaint relating to alleged migration of chemicals from **DP&L** property to the landfill was denied February 18, 2014, as were motions filed by DP&L and others to dismiss other portions of the complaint that were viewed by defendants as identical to the allegations dismissed in the first complaint proceeding. The Judge found that there were differences in the allegations and is permitting those allegations to proceed.. Limited discovery has been permitted pending resolution of the motion including some depositions of former **DP&L** employees during 2013 and into 2014. DP&L cannot predict the outcome of this proceeding.

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 previously indicated that the official release date for a proposed rule was in April 2013, it has been delayed, likely until late 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. On March 14, 2013, **DP&L** received the final report on the inspection of the Killen Station ash pond inspection from the USEPA which included recommended actions. **DP&L** has submitted a response with its actions to the USEPA. **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 the USEPA has opposed. On January 29, 2014, the parties to the litigation entered into a consent decree setting forth the USEPA's obligation to sign, by December 19, 2014, a notice for publication in the Federal Register taking action on the Agency's proposed Subtitle D option. The decree does not require Subtitle D regulation of coal combustion byproducts – it only requires the Agency to decide by that date whether or not to adopt the Subtitle D option. 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 NPDES permit program and the station's storm water pollution prevention plan. The notice requested that **DP&L** respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on **DP&L's** results of operations, financial condition or cash flows.

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 units 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.

Also see Notes 2 and 16 of Notes to **DPL's** Consolidated Financial Statements for additional information about the Merger and certain related legal matters.

Capital Expenditures for Environmental Matters

DP&L's environmental capital expenditures were approximately $2.0 million, $8.0 million and $12.0 million in 2013, 2012 and 2011, respectively. **DP&L** has budgeted $11.0 million in environmental related capital expenditures for 2014.

ELECTRIC SALES AND REVENUES

The following table sets forth **DPL's** electric sales and revenues for the years ended December 31, 2013 and 2012, the period November 28, 2011 (the Merger date) through December 31, 2011 (Successor), and the period January 1, 2011 through November 27, 2011 (Predecessor), respectively.

In the following table, we have included the combined Predecessor and Successor statistical information and results of operations. Such combined presentation is considered to be a non-GAAP disclosure. We have included such disclosure because we believe it facilitates the comparison of 2013 operating and financial performance to 2012 and 2011, and because the core operations of **DPL** have not changed as a result of the Merger.

	DPL				
	Successor		Combined	Successor	Predecessor
	Year ended December 31, 2013	Year ended December 31, 2012	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Electric sales (millions of kWh)	19,561	16,454	16,382	1,361	15,021
Billed electric customers (end of period)	692,670	637,708	516,887		

DPL is structured in two operating segments, **DP&L** and DPLER. See Note 17 of Notes to **DPL's** Consolidated Financial Statements for more information on **DPL's** segments. The following tables set forth **DP&L's** and DPLER's electric sales and revenues for the years ended December 31, 2013, 2012 and 2011, respectively.

	DP&L (a)		
	Year ended December 31, 2013	Year ended December 31, 2012	Year ended December 31, 2011
Electric sales (millions of kWh)	19,423	15,606	15,599
Billed electric customers (end of period)	514,926	513,282	513,383

	DPLER (b)		
	Year ended December 31, 2013	Year ended December 31, 2012	Year ended December 31, 2011
Electric sales (millions of kWh)	9,733	8,315	6,677
Billed electric customers (end of period)	308,047	198,098	40,171

(a) **DP&L** sold 5,874 million kWh, 6,201 million kWh and 5,731 million kWh of power to DPLER (a subsidiary of **DPL**) for the years ended December 31, 2013, 2012 and 2011, respectively.

(b) *This chart includes all sales of DPLER, both within and outside of the* ***DP&L*** *service territory.*

Item 1A – Risk Factors

Investors should consider carefully the following risk factors that could cause our business, operating results and financial condition to be materially adversely affected. New risks may emerge at any time, and we cannot predict those risks or estimate the extent to which they may affect our business or financial performance. These risk factors should be read in conjunction with the other detailed information concerning **DPL** set forth in the Notes to **DPL's** audited Consolidated Financial Statements and **DP&L** set forth in the Notes to **DP&L's** audited Financial Statements in Item 8 – Financial Statements and Supplementary Data and in Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations herein. The risks and uncertainties described below are not the only ones we face.

Customers have the opportunity to select alternative electric generation service providers, as permitted by Ohio legislation.

Customers can elect to buy generation service from a PUCO-certified CRES provider offering services to customers in **DP&L's** service territory. DPLER, a wholly-owned subsidiary of **DPL**, is one of those PUCO-certified CRES providers. Unaffiliated CRES providers also have been certified to provide energy in **DP&L's** service territory. Customer switching from **DP&L** to DPLER reduces **DPL's** revenues since the generation rates charged by DPLER are less than the SSO rates charged by **DP&L.** Increased competition by unaffiliated CRES providers in **DP&L's** service territory for retail generation service could result in the loss of existing customers and reduced revenues and increased costs to retain or attract customers. Decreased revenues and increased costs due to continued customer switching and customer loss could have a material adverse effect on our results of operations, financial condition and cash flows. The following are some of the factors that could result in increased switching by customers to PUCO-certified CRES providers in the future:

- low wholesale price levels have led, and may continue to lead, to existing CRES providers becoming more active in our service territory,
- additional CRES providers entering our territory, and

- we may experience increased customer switching through "governmental aggregation," where a municipality may contract with a CRES provider to provide generation service to the customers located within the municipal boundaries.

We are subject to extensive laws and local, state and federal regulation, as well as related litigation, that could affect our operations and costs.

We are subject to extensive laws and regulation by federal, state and local authorities, such as the PUCO, the CFTC, the USEPA, the Ohio EPA, the FERC, the Department of Labor and the Internal Revenue Service, among others. Regulations affect almost every aspect of our business, including in the areas of the environment, health and safety, cost recovery and rate making, the issuance of securities and incurrence of debt and taxation. New laws and regulations, and new interpretations of existing laws and regulations, are ongoing and we generally cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on our business. Complying with this regulatory environment requires us to expend a significant amount of funds and resources. The failure to comply with this regulatory environment could subject us to substantial financial costs and penalties and changes, either forced or voluntary, in the way we operate our business. Additional detail about the effect of this regulatory environment on our operations is included in the risk factors set forth below. In the normal course of business, we are also subject to various lawsuits, actions, proceedings, claims and other matters asserted under this regulatory environment or otherwise, which require us to expend significant funds to address, the outcomes of which are uncertain and the adverse resolutions of which could have a material adverse effect on our results of operations, financial condition and cash flows.

The costs we can recover and the return on capital we are permitted to earn for certain aspects of our business are regulated and governed by the laws of Ohio and the rules, policies and procedures of the PUCO.

On May 1, 2008, SB 221, an Ohio electric energy bill, was signed by the Governor of Ohio and became effective July 31, 2008. This law, among other things, required all Ohio distribution utilities to file either an ESP or MRO, and established a significantly excessive earnings test for Ohio public utilities that compares the utility's earnings to the earnings of other companies with similar business and financial risks. The PUCO order in the 2012 ESP case changed the Company's rate structure and the ability to recover certain costs which will affect our results of operations, cash flows and financial condition. **DP&L's** ESP and certain filings made by us in connection with this plan are further discussed under "Ohio Retail Rates" in Item 1 – Competition and Regulation.

In Ohio, retail generation rates are no longer subject to cost-based regulation, the distribution and transmission businesses are still regulated. While rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the PUCO will agree that all of our costs have been prudently incurred or are recoverable. There is also no assurance that the regulatory process in which rates are determined will always result in rates that will produce a full or timely recovery of our costs and permitted rates of return. Accordingly, the revenue **DP&L** receives may or may not match its expenses at any given time. Therefore, **DP&L** is subject to prevailing market prices for electricity and would not necessarily be able to charge rates that produce timely or full recovery of its expenses. Changes in, or reinterpretations of, the laws, rules, policies and procedures that set electric rates, permitted rates of return, changes in **DP&L's** rate structure, regulations regarding ownership of generation assets, transition to a competitive bid structure to supply retail generation service to SSO customers, reliability initiatives, fuel and purchased power (which account for a substantial portion of our operating costs), customer switching, capital expenditures and investments and other costs on a full or timely basis through rates, power market prices, and changes to the frequency and timing of rate increases could have a material adverse effect on our results of operations, financial condition and cash flows.

Our increased costs due to advanced energy and energy efficiency requirements may not be fully recoverable in the future.

SB 221 contains targets relating to advanced energy, renewable energy, peak demand reduction and energy efficiency standards. The standards require that, by the year 2025 and each year thereafter, 25% of the total number of kWh of electricity sold by the utility to retail electric consumers must come from alternative energy resources. These include "advanced energy resources" such as distributed generation, clean coal, advanced nuclear, energy efficiency and fuel cell technology; and "renewable energy resources" such as solar, hydro, wind, geothermal and biomass. At least half of the 25% must be generated from renewable energy resources, including solar energy. Annual renewable energy standards began in 2009 with increases in required percentages each year through 2024. The advanced energy standard must be met by 2025 and each year thereafter. Annual targets for energy efficiency began in 2009 and require increasing energy reductions each year compared to a baseline energy usage, up to 22.3% by 2025. Peak demand reduction targets began in 2009 with increases in required percentages each year, up to 7.75% by 2018. The advanced energy and renewable energy standards have increased our power supply costs and are expected to continue to increase (and could materially increase) these costs. **DP&L** is entitled to recover costs associated with its alternative energy compliance costs, as well as its energy efficiency and demand response programs. **DP&L** began recovering these costs in 2009. If in the future we are unable to timely or fully recover these costs, it could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, if we were found not to be in compliance with these standards, monetary penalties could apply. These penalties are not permitted to be recovered from customers and significant penalties could have a material adverse effect on our results of operations, financial condition and cash flows. The demand reduction and energy efficiency standards by design result in reduced energy and demand that could adversely affect our results of operations, financial condition and cash flows.

We have no control over the timing or terms of an order by the PUCO ordering us to separate our generation business into a separate legal entity from our distribution and transmission business.
As required by the 2013 ESP order, **DP&L** filed an application for authority to transfer or sell its generation assets no later than May 31, 2017. There can be no assurance of the terms on which the PUCO would authorize the separation of our generation business from our distribution and transmission business. Several regulatory filings and approvals are required in connection with the separation and certain other consents or approvals may be required under other agreements to which we are party.

The availability and cost of fuel has experienced and could continue to experience significant volatility and we may not be able to hedge the entire exposure of our operations from fuel availability and price volatility.
We purchase coal, natural gas and other fuel from a number of suppliers. The coal market in particular has experienced significant price volatility in the last several years. We are now in a global market for coal in which our domestic price is increasingly affected by international supply disruptions and demand balance. Coal exports from the U.S. have increased significantly at times in recent years. In addition, domestic issues like government-imposed direct costs and permitting issues that affect mining costs and supply availability, and the variable demand of retail customer load and the performance of our generation fleet have an impact on our fuel procurement operations. Our approach is to hedge the fuel costs for our anticipated electric sales. However, we may not be able to hedge the entire exposure of our operations from fuel price volatility. As of the date of this report, **DP&L** has substantially all of the expected coal volume needed under contract to meet its retail and wholesale sales requirements for 2014. In 2013, approximately 80% of **DP&L's** coal for stations it operates was provided by four suppliers, one of which was under a contract in excess of one year with **DP&L**. Historically, some of our suppliers and buyers of fuel have not performed on their contracts and have failed to deliver or accept fuel as specified under their contracts. To the extent our suppliers and buyers do not meet their contractual commitments and, as a result of such failure or otherwise, we cannot secure adequate fuel or sell excess fuel in a timely or cost-effective manner or we are not hedged against price volatility, we could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, **DP&L** is a co-owner of certain generation facilities where it is a non-operating owner. **DP&L** does not procure or have control over the fuel for these facilities, but is responsible for its proportionate share of the cost of fuel procured at these facilities. Co-owner operated facilities do not always have realized fuel costs that are equal to our co-owners' projections, and we are responsible for our proportionate share of any increase in actual fuel costs. Fuel and purchased power costs represent a large and volatile portion of **DP&L's** total cost. **DP&L** implemented a fuel and purchased power recovery mechanism beginning on January 1, 2010, which subjects our recovery of fuel and purchased power costs to tracking and adjustment on a seasonal quarterly basis for SSO customers. If in the future we are unable to timely or fully recover our fuel and purchased power costs, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Our use of derivative and nonderivative contracts may not fully hedge our generation assets, customer supply activities, or other market positions against changes in commodity prices, and our hedging procedures may not work as planned.
We transact in coal, power and other commodities to hedge our positions in these commodities. These trades are affected by a range of factors, including variations in power demand, fluctuations in market prices, market prices for alternative commodities and optimization opportunities. We have attempted to manage our commodities price risk exposure by establishing and enforcing risk limits and risk management policies. Despite our efforts, however, these risk limits and management policies may not work as planned and fluctuating prices and other events could adversely affect our results of operations, financial condition and cash flows. As part of our risk management, we use a variety of non-derivative and derivative instruments, such as swaps, futures and forwards, to manage our market risks. We also use interest rate derivative instruments to hedge against interest rate fluctuations related to our debt. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could

affect the reported fair value of some of these contracts. We could also recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform, which could result in a material adverse effect on our results of operations, financial condition and cash flows.

The Dodd-Frank Act contains significant requirements related to derivatives that, among other things, could reduce the cost effectiveness of entering into derivative transactions.

In July 2010, The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law. The Dodd-Frank Act 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. We are considered an end-user under the Dodd-Frank Act and therefore are exempt from most of the collateral and margining requirements. We are required to report our bilateral derivative contracts, unless our counterparty is a major swap participant or has elected to report on our behalf. Even though we 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. The occurrence of any of these events could have an adverse effect on our results of operations, financial condition and cash flows.

We are subject to numerous environmental laws and regulations that require capital expenditures, increase our cost of operations, may expose us to environmental liabilities or make continued operation of certain generating units unprofitable.

Our operations and facilities (both wholly-owned and co-owned with others) are subject to numerous and extensive federal, state and local environmental laws and regulations relating to various matters, including air quality (such as reductions in NO_x, SO_2 and particulate emissions), water quality, wastewater discharge, solid waste and hazardous waste. We could also become subject to additional environmental laws and regulations and other requirements in the future (such as reductions in mercury and other hazardous air pollutants, SO_3 (sulfur trioxide), regulation of ash generated from coal-based generating stations and reductions in GHG emissions as discussed in more detail in the next risk factor). With respect to our largest generation station, the Stuart Station, we are also subject to continuing compliance requirements related to NO_x, SO_2 and particulate matter emissions under **DP&L's** consent decree with the Sierra Club. Compliance with these laws, regulations and other requirements requires us to expend significant funds and resources and could at some point become prohibitively expensive or result in our shutting down (temporarily or permanently) or altering the operation of our facilities. Environmental laws and regulations also generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. If we are not able to timely obtain, maintain or comply with all licenses, permits, inspections and approvals required to operate our business, then our operations could be prevented, delayed or subject to additional costs. Failure to comply with environmental laws, regulations and other requirements may result in the imposition of fines and penalties or other sanctions and the imposition of stricter environmental standards and controls and other injunctive measures affecting operating assets. In addition, any alleged violation of these laws, regulations and other requirements may require us to expend significant resources to defend against any such alleged violations. **DP&L** owns a non-controlling interest in several generating stations operated by our co-owners. As a non-controlling owner in these generating stations, **DP&L** is responsible for its pro rata share of expenditures for complying with environmental laws, regulations and other requirements, but has limited control over the compliance measures taken by our co-owners. In addition, **DP&L's** ESP permits it to seek recovery for costs associated with new climate change or carbon regulations. In addition, if we were found not to be in compliance with these environmental laws, regulations or requirements, any penalties that would apply or other resulting costs would likely not be recoverable from customers. We could be subject to joint and several strict liabilities for any environmental contamination at our currently or formerly owned, leased or operated properties or third-party waste disposal sites. For example, contamination has been identified at two waste disposal sites for which we are alleged to have potential liability. In addition to potentially significant investigation and remediation costs, any such contamination matters can give rise to claims from governmental authorities and other third parties for fines or penalties, natural resource damages, personal injury and property damage.

Our costs and liabilities relating to environmental matters could have a material adverse effect on our results of operations, financial condition and cash flows.

If legislation or regulations at the federal, state or regional levels impose mandatory reductions of greenhouse gases on generation facilities, we could be required to make large additional capital investments and incur substantial costs.

There is an ongoing concern nationally and internationally among regulators, investors and others concerning global climate change and the contribution of emissions of GHGs, including most significantly CO_2. This concern has led to interest in legislation and action at the international, federal, state and regional levels, including regulation of GHG emissions by the USEPA, and litigation seeking to compel the promulgation or enforcement of

GHG requirements. Approximately 99% of the energy we produce is generated by coal. As a result of current or future legislation or regulations at the international, federal, state or regional levels imposing mandatory reductions of CO_2 and other GHGs on generation facilities, we could be required to make large additional capital investments and/or incur substantial costs in the form of taxes or emissions allowances. Such legislation and regulations could also impair the value of our generation stations or make some of these stations uneconomical to maintain or operate and could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing generation stations. Although **DP&L** is permitted under its current ESP to seek recovery of costs associated with new climate change or carbon regulations, our inability to fully or timely recover such costs could have a material adverse effect on our results of operations, financial condition and cash flows.

Fluctuations in our sales of coal and excess emission allowances could cause a material adverse effect on our results of operations, financial condition and cash flows for any particular period.
DP&L sells coal to other parties from time to time for reasons that include maintaining an appropriate balance between projected supply and projected use and as part of a coal price optimization program where coal under contract may be resold and replaced with other coal or power available in the market with a favorable price spread, adjusted for any quality differentials. Sales of coal are affected by a range of factors, including price volatility among the different coal basins and qualities of coal, variations in power demand and the market price of power compared to the cost to produce power. These factors could cause the amount and price of coal we sell to fluctuate, which could have a material adverse effect on our results of operations, financial condition and cash flows for any particular period.

DP&L may sell its excess emission allowances, including NO_x and SO_2 emission allowances, from time to time. Sales of any excess emission allowances are affected by a range of factors, such as general economic conditions, fluctuations in market demand, availability of excess inventory for sale and changes to the regulatory environment, including the implementation of CAIR or any replacement rule. These factors could cause the amount and price of excess emission allowances **DP&L** sells to fluctuate, which could have a material adverse effect on **DPL's** results of operations, financial condition and cash flows for any particular period. Although there has been overall reduced trading activity in the annual NO_x and SO_2 emission allowance trading markets in recent years, the adoption of regulations that regulate emissions or establish or modify emission allowance trading programs could affect the emission allowance trading markets and have a material effect on **DP&L's** emission allowance sales.

The operation and performance of our facilities are subject to various events and risks that could negatively affect our business.
The operation and performance of our generation, transmission and distribution facilities and equipment is subject to various events and risks, such as the potential breakdown or failure of equipment, processes or facilities, fuel supply or transportation disruptions, the loss of cost-effective disposal options for solid waste generated by our facilities (such as coal ash and gypsum), accidents, injuries, labor disputes or work stoppages by employees, operator error, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, performance below expected or required levels, weather-related and other natural disruptions, vandalism, events occurring on the systems of third parties that interconnect to and affect our system and the increased maintenance requirements, costs and risks associated with our aging generation units. Our results of operations, financial condition and cash flows could have a material adverse effect due to the occurrence or continuation of these events.

Diminished availability or performance of our transmission and distribution facilities could result in reduced customer satisfaction and regulatory inquiries and fines, which could have a material adverse effect on our results of operations, financial condition and cash flows. Operation of our owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and efficiency levels and likely result in lost revenues and increased expenses that could have a material adverse effect on our results of operations, financial condition and cash flows. In particular, since over 50% of our base-load generation is derived from co-owned generation stations operated by our co-owners, poor operational performance by our co-owners, misalignment of co-owners' interests or lack of control over costs (such as fuel costs) incurred at these stations could have an adverse effect on us. We have constructed and placed into service FGD facilities at most of our base-load generating stations. If there is significant operational failure of the FGD equipment at the generating stations, we may not be able to meet emission requirements at some of our generating stations or, at other stations, it may require us to burn more expensive types of coal or procure additional emission allowances. These events could result in a substantial increase in our operating costs. Depending on the degree, nature, extent, or willfulness of any failure to comply with environmental requirements, including those imposed by any consent decrees, such non-compliance could result in the imposition of penalties or the shutting down of the affected generating stations, which could have a material adverse effect on our results of operations, financial condition and cash flows.

Asbestos and other regulated substances are, and may continue to be, present at our facilities. We have been named as a defendant in asbestos litigation, which at this time is not material to us. The continued presence of asbestos and other regulated substances at these facilities could result in additional litigation being brought against us, which could have a material adverse effect on our results of operations, financial condition and cash flows.

If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. These would likely not be recoverable from customers through regulated rates and could have a material adverse effect on our results of operations, financial condition and cash flows.

As an owner and operator of a bulk power transmission system, **DP&L** is subject to mandatory reliability standards promulgated by the NERC and enforced by the FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and is guided by reliability and market interface principles. In addition, **DP&L** is subject to Ohio reliability standards and targets. Compliance with reliability standards subjects us to higher operating costs or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the PUCO will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates and could have a material adverse effect on our results of operations, financial condition and cash flows.

Our financial results may fluctuate on a seasonal and quarterly basis or as a result of severe weather.

Weather conditions significantly affect the demand for electric power. In our Ohio service territory, demand for electricity is generally greater in the summer months associated with cooling and in the winter months associated with heating compared to other times of the year. Unusually mild summers and winters could therefore have an adverse effect on our results of operations, financial condition and cash flows. In addition, severe or unusual weather, such as hurricanes and ice or snow storms, may cause outages and property damage that may require us to incur additional costs that may not be insured or recoverable from customers. While **DP&L** is permitted to seek recovery of storm damage costs under its ESP, if **DP&L** is unable to fully recover such costs in a timely manner, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Our membership in a regional transmission organization presents risks that could have a material adverse effect on our results of operations, financial condition and cash flows.

On October 1, 2004, in compliance with Ohio law, **DP&L** turned over control of its transmission functions and fully integrated into PJM, a regional transmission organization. The price at which we can sell our generation capacity and energy is now 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 business rules. While we can continue to make bilateral transactions to sell our generation through a willing-buyer and willing-seller relationship, any transactions that are not pre-arranged are subject to market conditions at PJM. To the extent we sell electricity into the power markets on a contractual basis, we are not guaranteed any rate of return on our capital investments through mandated rates. The results of the PJM RPM base residual auction are impacted by the supply and demand of generation and load and also may be impacted by congestion and PJM rules relating to bidding for Demand Response and Energy Efficiency resources and other factors. Auction prices could fluctuate substantially over relatively short periods of time and adversely affect our results of operations, financial condition and cash flows. We cannot predict the outcome of future auctions, but low auction prices could have a material adverse effect on our results of operations, financial condition and cash flows.

The rules governing the various regional power markets may also change from time to time which could affect our costs and revenues and have a material adverse effect on our results of operations, financial condition and cash flows. We may be required to expand our transmission system according to decisions made by PJM rather than our internal planning process. Various proposals and proceedings before FERC may cause transmission rates to change from time to time. In addition, PJM has been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial effect on us. We also incur fees and costs to participate in PJM.

SB 221 includes a provision that allows electric utilities to seek and obtain recovery of RTO-related charges. Therefore, RTO-related costs associated with serving SSO load are being recovered through our SSO retail rates. If in the future, however, we are unable to recover all of these costs in a timely manner, and since the SSO retail riders are bypassable when additional customer switching occurs, this could have a material adverse effect on our results of operations, financial condition and cash flows.

As members of PJM, **DP&L** and DPLE are also subject to certain additional risks including those associated with the allocation of losses caused by unreimbursed defaults of other participants in PJM markets among PJM members and those associated with complaint cases filed against PJM that may seek refunds of revenues previously earned by PJM members including **DP&L** and DPLE. These amounts could be significant and have a material adverse effect on our results of operations, financial condition and cash flows.

Costs associated with new transmission projects could have a material adverse effect on our results of operations, financial condition and cash flows.
Annually, PJM performs a review of the capital additions required to provide reliable electric transmission services throughout its territory. PJM traditionally allocated the costs of constructing these facilities to those entities that benefited directly from the additions. Over the last several years, however, some of the costs of constructing new large transmission facilities have been "socialized" across PJM without a direct relationship between the costs assigned to and benefits received by particular PJM members. To date, the additional costs charged to **DP&L** for new large transmission approved projects have not been material. Over time, as more new transmission projects are constructed and if the allocation method is not changed, the annual costs could become material. **DP&L** is recovering the Ohio retail jurisdictional share of these allocated costs from its SSO retail customers through the TCRR rider. To the extent that any costs in the future are material and we are unable to recover them from our customers, it could have a material adverse effect on our results of operation, financial condition and cash flows.

Our inability to obtain financing on reasonable terms, or at all, with creditworthy counterparties could adversely affect our results of operations, financial condition and cash flows.
From time to time we rely on access to the credit and capital markets to fund certain operational and capital costs. These capital and credit markets have experienced extreme volatility and disruption and the ability of corporations to obtain funds through the issuance of debt or equity has been negatively impacted. Disruptions in the credit and capital markets make it harder and more expensive to obtain funding for our business. Access to funds under our existing financing arrangements is also dependent on the ability of our counterparties to meet their financing commitments. Our inability to obtain financing on reasonable terms, or at all, with creditworthy counterparties could adversely affect our results of operations, financial condition and cash flows. If our available funding is limited or we are forced to fund our operations at a higher cost, these conditions may require us to curtail our business activities and increase our cost of funding, both of which could reduce our profitability. **DP&L** has variable rate debt that bears interest based on a prevailing rate that is reset weekly based on a market index that can be affected by market demand, supply, market interest rates and other market conditions. We also currently maintain both cash on deposit and investments in cash equivalents that could be adversely affected by interest rate fluctuations. In addition, ratings agencies issue credit ratings on us and our debt that affect our borrowing costs under our financial arrangements and affect our potential pool of investors and funding sources. Our credit ratings also govern the collateral provisions of certain of our contracts. As a result of the Merger and assumption by **DPL** of merger-related debt and other factors, our credit ratings were downgraded, resulting in increased borrowing costs and causing us to post cash collateral with certain of our counterparties. If the rating agencies were to downgrade our credit ratings further, our borrowing costs would likely further increase, our potential pool of investors and funding resources could be reduced, and we could be required to post additional cash collateral under selected contracts. These events would likely reduce our liquidity and profitability and could have a material adverse effect on our results of operations, financial condition and cash flows.

A material change in market interest rates could adversely affect our results of operations, financial condition and cash flows.
DPL and **DP&L** have variable rate debt that bears interest based on a prevailing rate that is regularly reset and that can be affected by market demand, supply, market interest rates and other market conditions. We also currently maintain both cash on deposit and investments in cash equivalents that could be adversely affected by interest rate fluctuations. Any event which impacts market interest rates could have a material adverse effect on our results of operations, financial condition and cash flows.

Poor investment performance of our benefit plan assets and other factors impacting benefit plan costs could unfavorably affect our liquidity and results of operations.
The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under our pension and postemployment benefit plans. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. A decline in the market value of the pension and postemployment benefit plan assets will increase the funding requirements under our pension and postemployment benefit plans if the actual asset returns do not recover these declines in

value in the foreseeable future. Future pension funding requirements, and the timing of funding payments, may also be subject to changes in legislation. The Pension Protection Act, enacted in August 2006, requires underfunded pension plans to improve their funding ratios within prescribed intervals based on the level of their underfunding. As a result, our required contributions to these plans at times have increased and may increase in the future. In addition, our pension and postemployment benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the discounted liabilities increase benefit expense and funding requirements. Further, changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase the funding requirements for the obligations related to the pension and other postemployment benefit plans. Declines in market values and increased funding requirements could have a material adverse effect on our results of operations, financial condition and cash flows.

Our businesses depend on counterparties performing in accordance with their agreements. If they fail to perform, we could incur substantial expense, which could adversely affect our liquidity, cash flows and results of operations.

We enter into transactions with and rely on many counterparties in connection with our business, including for the purchase and delivery of inventory, including fuel and equipment components (such as limestone for our FGD equipment), for our capital improvements and additions and to provide professional services, such as actuarial calculations, payroll processing and various consulting services. If any of these counterparties fails to perform its obligations to us or becomes unavailable, our business plans may be materially disrupted, we may be forced to discontinue certain operations if a cost-effective alternative is not readily available or we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and cause delays. These events could cause our results of operations, financial condition and cash flows to have a material adverse effect.

Our consolidated results of operations may be negatively affected by overall market, economic and other conditions that are beyond our control.

Economic pressures, as well as changing market conditions and other factors related to physical energy and financial trading activities, which include price, credit, liquidity, volatility, capacity, transmission and interest rates, can have a significant effect on our operations and the operations of our retail, industrial and commercial customers and our suppliers. The direction and relative strength of the economy has been increasingly uncertain due to softness in the real estate and mortgage markets, volatility in fuel and other energy costs, difficulties in the financial services sector and credit markets, high unemployment and other factors. Many of these factors have affected our Ohio service territory.

Overall lower prices in the retail electricity market 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 SSO. 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. These factors may reduce our margins and could have a material adverse effect on our results of operations, financial condition and cash flows.

Our results of operations, financial condition and cash flows may be negatively affected by sustained downturns or a sluggish economy. Sustained downturns, recessions or a sluggish economy generally affect the markets in which we operate and negatively influence our energy operations. A contracting, slow or sluggish economy could reduce the demand for energy in areas in which we are doing business. During economic downturns, our commercial and industrial customers may see a decrease in demand for their products, which in turn may lead to a decrease in the amount of energy they require. In addition, our customers' ability to pay us could also be impaired, which could result in an increase in receivables and write-offs of uncollectible accounts. Our suppliers could also be affected by the economic downturn resulting in supply delays or unavailability. Reduced demand for our electric services, failure by our customers to timely remit full payment owed to us and supply delays or unavailability could have a material adverse effect on our results of operations, financial condition and cash flows.

Accidental improprieties and undetected errors in our internal controls and information reporting could result in the disallowance of cost recovery, noncompliant disclosure and reporting or incorrect payment processing.

Our internal controls, accounting policies and practices and internal information systems are designed to enable us to capture and process transactions and information in a timely and accurate manner in compliance with GAAP in the United States of America, laws and regulations, taxation requirements and federal securities laws and regulations in order to, among other things, disclose and report financial and other information in connection with the recovery of our costs and with our reporting requirements under federal securities, tax and other laws and regulations and to properly process payments. We have also implemented corporate governance, internal control and accounting policies and procedures in connection with the Sarbanes-Oxley Act of 2002. Our internal controls and policies have been and continue to be closely monitored by management and our Board of Directors. While we believe these controls, policies, practices and systems are adequate to verify data integrity, unanticipated and unauthorized actions of employees, temporary lapses in internal controls due to shortfalls in oversight or resource constraints could lead to improprieties and undetected errors that could result in the disallowance of cost recovery, noncompliant disclosure and reporting or incorrect payment processing. The consequences of these events could have a material adverse effect on our results of operations, financial condition and cash flows.

New accounting standards or changes to existing accounting standards could materially affect how we report our results of operations, financial condition and cash flows.
Our Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in the United States of America. The SEC, FASB or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require us to change our accounting policies. These changes are beyond our control, can be difficult to predict and could materially affect how we report our results of operations, financial condition and cash flows. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial condition. In addition, in preparing our Consolidated Financial Statements, management is required to make estimates and assumptions. Actual results could differ significantly from those estimates.

The SEC is investigating the potential transition to the use of IFRS promulgated by the International Accounting Standards Board for U.S. companies. Adoption of IFRS could result in significant changes to our accounting and reporting, such as in the treatment of regulatory assets and liabilities and property. The SEC does not currently have a timeline regarding the mandatory adoption of IFRS. We are currently assessing the effect that this potential change would have on our Consolidated Financial Statements and we will continue to monitor the development of the potential implementation of IFRS.

If we are unable to maintain a qualified and properly motivated workforce, it could have a material adverse effect on our results of operations, financial condition and cash flows.
One of the challenges we face is to retain a skilled, efficient and cost-effective workforce while recruiting new talent to replace losses in knowledge and skills due to resignations, terminations or retirements. This undertaking could require us to make additional financial commitments and incur increased costs. If we are unable to successfully attract and retain an appropriately qualified workforce, it could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, we have employee compensation plans that reward the performance of our employees. We seek to ensure that our compensation plans encourage acceptable levels for risk and high performance through pay mix, performance metrics and timing. We also have policies and procedures in place to mitigate excessive risk-taking by employees since excessive risk-taking by our employees to achieve performance targets could result in events that could have a material adverse effect on our results of operations, financial condition and cash flows.

We are subject to collective bargaining agreements and other employee workforce factors that could affect our businesses.
Over half of our employees are represented by a collective bargaining agreement that is in effect until October 31, 2014. While we believe that we maintain a satisfactory relationship with our employees, it is possible that labor disruptions affecting some or all of our operations could occur during the period of the collective bargaining agreement or at the expiration of the collective bargaining agreement before a new agreement is negotiated. Work stoppages by, or poor relations or ineffective negotiations with, our employees could have a material adverse effect on our results of operations, financial condition and cash flows.

Potential security breaches (including cybersecurity breaches) and terrorism risks could adversely affect our businesses.
We operate in a highly regulated industry that requires the continued operation of sophisticated systems and network infrastructure at our generation stations, fuel storage facilities and transmission and distribution facilities. We also use various financial, accounting and other systems in our businesses. These systems and facilities are vulnerable to unauthorized access due to hacking, viruses, other cybersecurity attacks and other causes. In particular, given the importance of energy and the electric grid, there is the possibility that our systems and facilities could be targets of terrorism or acts of war. We have implemented measures to help prevent unauthorized access to our systems and facilities, including certain measures to comply with mandatory regulatory reliability standards. Despite our efforts, if our systems or facilities were to be breached or disabled, we may be unable to recover them in a timely way to fulfill critical business functions, including the supply of electric services to our customers, and we could experience decreases in revenues and increases in costs that could adversely affect our results of operations, cash flows and financial condition.

In the course of our business, we also store and use customer, employee, and other personal information and other confidential and sensitive information. If our third party vendors' systems were to be breached or disabled, sensitive and confidential information and other data could be compromised, which could result in negative publicity, remediation costs and potential litigation, damages, consent orders, injunctions, fines and other relief.

To help mitigate against these risks, we maintain insurance coverage against some, but not all, potential losses, including coverage for illegal acts against us. However, insurance may not be adequate to protect us against all costs and liabilities associated with these risks.

DPL is a holding company and parent of DP&L and other subsidiaries. DPL's cash flow is dependent on the operating cash flows of DP&L and its other subsidiaries and their ability to pay cash to DPL.

DPL is a holding company and its investments in its subsidiaries are its primary assets. A significant portion of **DPL's** business is conducted by its **DP&L** subsidiary. As such, **DPL's** cash flow is dependent on the operating cash flows of **DP&L** and its ability to pay cash to **DPL**. **DP&L's** governing documents contain certain limitations on the ability to declare and pay dividends to **DPL** while preferred stock is outstanding. Certain of **DP&L's** debt agreements also contain limits with respect to the ability of **DP&L** to incur debt. In addition, **DP&L** is regulated by the PUCO, which possesses broad oversight powers to ensure that the needs of utility customers are being met. While we are not currently aware of any plans to do so, the PUCO could attempt to impose restrictions on the ability of **DP&L** to distribute, loan or advance cash to **DPL** pursuant to these broad powers. 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. While we do not expect any of the foregoing restrictions to significantly affect **DP&L's** ability to pay funds to **DPL** in the future, a significant limitation on **DP&L's** ability to pay dividends or loan or advance funds to **DPL** would have a material adverse effect on **DPL's** results of operations, financial condition and cash flows.

Impairment of goodwill or long-lived assets would negatively affect our consolidated results of operations and net worth.

Goodwill represents the future economic benefits arising from assets acquired in a business combination (acquisition) that are not individually identified and separately recognized. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if impairment indicators are present. In evaluating the potential impairment of goodwill, we make estimates and assumptions about revenue, operating cash flows, capital expenditures, growth rates and discount rates based on our budgets and long-term forecasts, macroeconomic projections, and current market expectations of returns on similar assets. There are inherent uncertainties related to these factors and management's judgment in applying these factors. Generally, the fair value of a reporting unit is determined using a discounted cash flow valuation model. We could be required to evaluate the potential impairment of goodwill outside of the required annual assessment process if we experience situations, including but not limited to: deterioration in general economic conditions, operating or regulatory environment; increased competitive environment; increase in fuel costs particularly when we are unable to pass along such costs to customers; negative or declining cash flows; loss of a key contract or customer, particularly when we are unable to replace it on equally favorable terms; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. See Note 18 of Notes to **DPL's** Consolidated Financial Statements for more information on the impairment of Goodwill.

Long-lived assets are initially recorded at fair value when acquired in a business combination and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long-lived assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above. See Note 19 of Notes to **DPL's** Financial Statements for more information on the impairment of fixed assets. See Note 15 of Notes to **DP&L's** Financial Statements for more information on the impairment of fixed assets.

Item 1B – Unresolved Staff Comments

None

Item 2 – Properties

Information relating to our properties is contained in Item 1 – Electric Operations and Fuel Supply and Note 5 of Notes to **DPL's** Consolidated Financial Statements and Note 5 of Notes to **DP&L's** Financial Statements.

Substantially all property and stations of **DP&L** are subject to the lien of the First and Refunding Mortgage.

Item 3 - Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We are also from time to time involved in other reviews, investigations and proceedings by governmental and regulatory agencies regarding our business, certain of which may result in adverse judgments, settlements, fines, penalties, injunctions or other relief. We believe the amounts provided in our Consolidated Financial Statements, as prescribed by GAAP, for these matters are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters (including those matters noted below) and to comply with applicable laws and regulations will not exceed the amounts reflected in our Consolidated Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2013, cannot be reasonably determined.

The following additional information is incorporated by reference into this Item: (i) information about the legal proceedings contained in Item 1 – Competition and Regulation of Part 1 of this Annual Report on Form 10-K and (ii) information about the legal proceedings contained in Item 8 – Financial Statements and Supplementary Data – Note 16 of Notes to **DPL's** Consolidated Financial Statements of Part II of this Annual Report on Form 10-K.

Item 4 – Mine Safety Disclosures

Not applicable.

PART II

Item 5 – Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

All of the outstanding common stock of **DPL** is owned, and has been owned throughout all of 2013 and 2012, indirectly by AES and directly by an AES wholly-owned subsidiary. As a result, our stock is not listed for trading on any stock exchange. **DP&L's** common stock is held solely by **DPL** and, as a result, is not listed for trading on any stock exchange.

Dividends

During the year ended December 31, 2012 (Successor), **DPL** declared dividends on its common stock to its parent of $70.0 million. During the year ended December 31, 2013, **DPL's** Board of Directors amended the prior dividend declaration to be equal to the amount paid, $19.1 million, reversing $5.9 million of the 2012 dividends. During the period January 1, 2011 through November 27, 2011 (Predecessor), **DPL** declared dividends of $1.54 per share of common stock. Of this amount, $0.54 per share was paid during the period November 28, 2011 through December 31, 2011 (Successor). During the year ended December 31, 2010, **DPL** declared and paid dividends per share of common stock of $1.21. **DP&L** declares and pays dividends on its common shares to its parent **DPL** from time to time as declared by the **DP&L** board. Dividends on common shares in the amount of $190.0 million, $145.0 million and $220.0 million were declared in the years ended December 31, 2013, 2012 and 2011, respectively. **DP&L** declared and paid dividends on preferred shares in the amount of $0.9 million in each of the years ended December 31, 2013, 2012 and 2011.

DPL's Amended Articles of Incorporation (the "Articles") contain provisions which state that **DPL** may not make a distribution to its shareholder or make a loan to any of its affiliates (other than its subsidiaries), unless: (a) there exists no Event of Default (as defined in the Articles) and no such Event of Default would result from the making of the distribution or loan; **and** either (b)(i) at the time of, and/or as a result of, the distribution or loan, **DPL's** leverage ratio does not exceed 0.67 to 1.00 and **DPL's** interest coverage ratio is not less than 2.50 to 1.00 or, (b)(ii) if such ratios are not within the parameters, **DPL's** senior long-term debt rating from one of the three major credit rating agencies is at least investment grade. Further, the restrictions on the payment of distributions to a shareholder and the making of loans to its affiliates (other than subsidiaries) cease to be in effect if the three major credit rating agencies confirm that a lowering of **DPL's** senior long-term debt rating below investment grade by the credit rating agencies would not occur without these restrictions.

As of December 31, 2013, there was no Event of Default - **DPL's** Articles generally define an "Event of Default" as either (i) a breach of a covenant or obligation under the Articles; (ii) the entering of an order of insolvency or bankruptcy by a court and that order remains in effect and unstayed for 180 days; or (iii) **DPL**, **DP&L** or one of its principal subsidiaries commences a voluntary case under bankruptcy or insolvency laws or consents to the appointment of a trustee, receiver or custodian to manage all of the assets of **DPL**, **DP&L** or one of its principal subsidiaries – but **DPL's** leverage ratio was at 0.89 to 1.00 and **DPL's** senior long-term debt rating from all three major credit rating agencies was below investment grade. As a result, and as of December 31, 2013, **DPL** was prohibited under its Articles from making a distribution to its shareholder or making a loan to any of its affiliates (other than its subsidiaries).

DPL's unsecured revolving credit agreement and **DPL's** unsecured term loan were refinanced on May 10, 2013. The new loan agreements include a provision which restricts all dividend payments from **DPL** to AES until after the maturity or termination of the respective credit facilities.

As long as **DP&L** preferred stock is outstanding, **DP&L's** Amended Articles of Incorporation 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, 2013, **DP&L's** retained earnings of $426.8 million were all available for **DP&L** common stock dividends payable to **DPL**.

Item 6 – Selected Financial Data

The following table presents our selected consolidated financial data which should be read in conjunction with our audited Consolidated Financial Statements and the related Notes thereto and Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations. The "Results of Operations" discussion in Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations addresses significant fluctuations in operating data. **DPL** is a wholly-owned, indirect subsidiary of AES and therefore does not report earnings or dividends on a per-share basis. Other data that management believes is important in understanding trends in our business are also included in this table.

DPL						
	Successor (a)			Predecessor (a)		
$ in millions except per share amounts or as indicated	**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31, 2010	Year ended December 31, 2009
Basic earnings per share of common stock (b)	**N/A**	N/A	N/A	$ 1.31	$ 2.51	$ 2.03
Diluted earnings per share of common stock (b)	**N/A**	N/A	N/A	$ 1.31	$ 2.50	$ 2.01
Dividends declared per share of common stock (c)	**N/A**	N/A	N/A	$ 1.54	$ 1.21	$ 1.14
Dividend payout ratio (c)	**N/A**	N/A	N/A	117.6%	48.2%	56.2%
Total electric sales (millions of kWh)	**19,561**	16,454	1,361	15,021	17,237	16,667
Results of operations:						
Revenues	**$ 1,636.9**	$ 1,668.4	$ 156.9	$ 1,670.9	$ 1,831.4	$ 1,539.4
Goodwill impairment (d)	**$ (306.3)**	$ (1,817.2)	$ -	$ -	$ -	$ -
Fixed-asset impairment (f)	**$ (26.2)**	$ -	$ -	$ -	$ -	$ -
Net income / (loss) (b)	**$ (222.0)**	$ (1,729.8)	$ (6.2)	$ 150.5	$ 290.3	$ 229.1
Financial position items at December 31:						
Total assets	**$ 3,721.5**	$ 4,247.3	$ 6,136.2	N/A	$ 3,813.3	$ 3,641.7
Long-term debt (e)	**$ 2,284.2**	$ 2,025.0	$ 2,628.9	N/A	$ 1,026.6	$ 1,223.5
Total construction additions	**$ 114.4**	$ 179.6	$ 201.0	N/A	$ 151.4	$ 145.3
Redeemable preferred stock of subsidiary	**$ 18.4**	$ 18.4	$ 18.4	N/A	$ 22.9	$ 22.9

DP&L					
$ in millions except per share amounts or as indicated	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011	Year ended December 31, 2010	Year ended December 31, 2009
Total electric sales (millions of kWh)	**19,423**	15,606	15,599	17,083	16,590
Results of operations:					
Revenues	**$ 1,551.5**	$ 1,531.8	$ 1,677.7	$ 1,738.8	$ 1,500.8
Fixed-asset impairment [f]	**$ (86.0)**	$ (80.8)	$ -	$ -	$ -
Earnings on common stock [g]	**$ 82.7**	$ 90.3	$ 192.3	$ 276.8	$ 258.0
Financial position items at December 31:					
Total assets	**$ 3,313.1**	$ 3,464.2	$ 3,538.3	$ 3,475.4	$ 3,457.4
Long-term debt [e]	**$ 876.9**	$ 332.7	$ 903.0	$ 884.0	$ 783.7
Redeemable preferred stock	**$ 22.9**	$ 22.9	$ 22.9	$ 22.9	$ 22.9
Number of shareholders - preferred stock	**196**	209	223	234	242

(a) "Predecessor" refers to the operations of **DPL** and its subsidiaries prior to the consummation of the Merger. "Successor" refers to the operations of **DPL** and its subsidiaries subsequent to the Merger. See Note 2 of Notes to **DPL's** Consolidated Financial Statements for a description of this transaction. As of the Merger date, the disclosure of per share amounts no longer applies.

(b) **DPL** incurred merger-related costs of $37.9 million ($24.6 million net of tax) and a $15.7 million ($10.2 million net of tax) in the 2011 Predecessor and Successor periods, respectively, and had a $25.1 million ($16.3 million net of tax) favorable adjustment in the period January 1, 2011 through November 27, 2011 as a result of the approval of the fuel settlement agreement by the PUCO.

(c) Of the $1.54 declared in the January 1, 2011 through November 27, 2011 period, $0.54 was paid in the November 28, 2011 through December 31, 2011 period.

(d) Goodwill impairment of $306.3 million and $1,817.2 million was recorded in 2013 and 2012, respectively.

(e) Excludes current maturities of long-term debt.

(f) For **DPL**, a fixed-asset impairment of $26.2 million ($17.0 million net of tax) was recorded in 2013. For **DP&L**, fixed-asset impairments of $86.0 million ($55.9 million net of tax) and $80.8 million ($51.8 million net of tax) was recorded in 2013 and 2012, respectively.

(g) In 2011, **DP&L** incurred merger-related costs of $19.4 million ($12.6 million net of tax) and had a $25.1 million ($16.3 million net of tax) favorable adjustment as a result of the approval of the fuel settlement agreement by the PUCO.

Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

The following discussion and analysis should be read in conjunction with **DPL's** audited Consolidated Financial Statements and the related Notes thereto and **DP&L's** audited Financial Statements and the related Notes thereto included in Item 8 – Financial Statements and Supplementary Data of this Form 10-K. The following discussion contains forward-looking statements. Our actual results may differ materially from the results suggested by these forward-looking statements. Please see "Forward-Looking Statements" at the beginning of this Form 10-K and Item 1A – Risk Factors. For a list of certain abbreviations or acronyms in this discussion, see Glossary at the beginning of this Form 10-K.

BUSINESS OVERVIEW

DPL is a regional electric energy and utility company. **DPL's** two reporting segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary and DPLER's subsidiary, MC Squared. See Note 17 of Notes to **DPL's** Consolidated Financial Statements for more information relating to these reportable segments. **DP&L** does not have any reportable segments.

DP&L is primarily engaged in the generation, transmission and distribution of electricity in West Central Ohio and the sale of energy to DPLER in Ohio and Illinois. **DPL** and **DP&L** strive to achieve disciplined growth in energy margins while limiting volatility in both cash flows and earnings and to achieve stable, long-term growth through efficient operations and strong customer and regulatory relations. More specifically, **DPL's** and **DP&L's** strategy is to match energy supply with load or customer demand, maximizing profits while effectively managing exposure to movements in energy and fuel prices and utilizing the transmission and distribution assets that transfer electricity at the most efficient cost while maintaining the highest level of customer service and reliability.

We operate and manage generation assets and are exposed to a number of risks. These risks include, but are not limited to, electricity wholesale price risk, PJM capacity price risk, regulatory risk, environmental risk, fuel supply and price risk, customer switching risk and the risk associated with electric generating station performance. We attempt to manage these risks through various means. For instance, we operate a portfolio of wholly-owned and jointly-owned generation assets that is diversified as to coal source, cost structure and operating characteristics. We are focused on the operating efficiency of these stations and maintaining their availability.

We operate and manage transmission and distribution assets in a rate-regulated environment. Accordingly, this subjects us to regulatory risk in terms of the costs that we may recover and the investment returns that we may collect in customer rates. We are focused on delivering electricity and maintaining high standards of customer service and reliability in a cost-effective manner.

Additional information relating to our risks is contained in Item 1A – Risk Factors.

The following discussion should be read in conjunction with the accompanying Consolidated Financial Statements and related footnotes included in Item 8 – Financial Statements and Supplementary Data.

BUSINESS COMBINATION

Acquisition by The AES Corporation

On November 28, 2011, **DPL** merged with Dolphin Sub, Inc., a wholly-owned subsidiary of AES pursuant to the Merger agreement whereby AES acquired **DPL** for $30.00 per share in a cash transaction valued at approximately $3.5 billion. At closing, **DPL** became a wholly-owned subsidiary of AES.

See Item 1A – Risk Factors, and Note 2 of Notes to **DPL's** Consolidated Financial Statements for additional risks and information related to the Merger.

Dolphin Subsidiary II, Inc., a subsidiary of AES, issued $1.25 billion in long-term Senior Notes on October 3, 2011, to partially finance the Merger. See Note 2 of Notes to **DPL's** Consolidated Financial Statements. Upon the consummation of the Merger, Dolphin Subsidiary II, Inc. was merged into **DPL** and these notes became long-term debt obligations of **DPL**. This debt has had and will continue to have a material effect on **DPL's** cash requirements.

DPL incurred Merger transaction costs consisting primarily of banker's fees, legal fees and change of control costs of approximately $53.6 million pre-tax during 2011. Other than these costs, interest on the additional debt and other items noted above, the Merger did not significantly affect **DPL** and **DP&L's** sources of liquidity.

Predecessor and Successor Financial Presentation

DPL's financial statements and related financial and operating data include the periods before and after the Merger date, and are labeled as Predecessor and Successor, respectively. In accordance with GAAP, **DPL** applied push-down accounting to account for the Merger. For accounting purposes only, push-down accounting created a new cost basis assigned to assets, liabilities and equity as of the Merger date. AES finalized its purchase price allocation during the third quarter of 2012. Consequently, **DPL's** results of operations and cash flows for the Predecessor and Successor periods are not presented on a comparable basis and therefore are shown separately, rather than combined, in its audited financial statements.

In the Management's Discussion and Analysis of Results of Operations and Financial Condition, we have included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such combined presentation is considered to be a non-GAAP disclosure. We have included such disclosure because we believe it facilitates the comparison of 2013, 2012 and 2011 operating and financial performance, and because the core operations of **DPL** have not changed as a result of the Merger.

REGULATORY ENVIRONMENT

DPL, **DP&L** and our subsidiaries' facilities and operations are subject to a wide range of environmental regulations and laws by federal, state and local authorities. As well as imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at these facilities to comply, or to determine compliance, with such regulations. We record liabilities for losses that are probable of occurring and can be reasonably estimated.

- **Carbon Dioxide and Other Greenhouse Gas Emissions**

  There is on-going concern nationally and internationally about global climate change and the contribution of emissions of GHGs, including most significantly CO_2. This concern has led to regulation and interest in legislation at the federal level, actions at the state level as well as litigation relating to GHG emissions. In 2007, a U.S. Supreme Court decision upheld that the USEPA has the authority to regulate GHG emissions under the CAA. In April 2009, the USEPA issued a proposed endangerment finding under the CAA. The proposed finding determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This endangerment finding became effective in January 2010.

  Various industry groups and states petitioned the U.S. Supreme Court to review the D.C. Circuit Court's recent decision to uphold the USEPA's endangerment finding and certain GHG regulations based on that endangerment finding. On October 15, 2013, the U.S. Supreme Court agreed to review several related cases addressing the USEPA's authority to issue GHG Prevention of Significant Deterioration permits under Section 165 of the CAA. As a result of the endangerment finding and other USEPA regulations, *emissions of CO_2 and other GHGs from EGUs and other stationary sources are subject to regulation.* Increased pressure for GHG emissions reduction is also coming from investor organizations and the international community. Environmental advocacy groups are also focusing considerable attention on GHG emissions from power generation facilities and their potential role in climate change. Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 14 million tons annually. If we are required to implement control of CO_2 and other GHGs at generation facilities, the cost to **DPL** and **DP&L** of such controls could be material.

- **Clean Water Act**

  In April 2012, **DP&L** received an NOV related to the construction of the Carter Hollow landfill at the Stuart Station. The NOV indicated that construction activities caused sediment to flow into downstream creeks. **DP&L** is in the process of resolving this NOV with the Ohio EPA. 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** installed sedimentation ponds as part of the runoff control measures to address this issue and worked with the various agencies to resolve their concerns. In March 2013, **DP&L** received a proposed Administrative Order from the USEPA which, after negotiation of the terms and conditions, was signed by **DP&L** management on May 30, 2013. A final Consent Agreement and Final Order was executed on July 8, 2013 and the previously issued permit was reinstated by the Corps on October 29, 2013.

- **NO_x and SO_2 Emissions – CSAPR**

  The CAIR final rules were published on May 12, 2005. CAIR created an interstate trading program for annual NO_x emission allowances and made modifications to an existing trading program for SO_2. Litigation brought by entities not including **DP&L** resulted in a decision by the U.S. Court of Appeals for the District of Columbia Circuit on July 11, 2008 to vacate CAIR and its associated Federal Implementation Plan. On December 23, 2008, the U.S. Court of Appeals issued an order on reconsideration that permits CAIR to remain in effect until the USEPA issues new regulations that would conform to the CAA requirements and the Court's July 2008 decision.

  In an attempt to conform to the Court's decision, the USEPA issued CSAPR on July 6, 2011, but subsequent litigation resulted in CSAPR being vacated and CAIR being reinstated pending the promulgation of a replacement rule. On December 10, 2013, the U.S. Supreme Court heard oral arguments as part of its review of the decision to vacate CSAPR. The Ohio EPA has a State Implementation Plan (SIP) that incorporates the CAIR program requirements, which remain in effect pending judicial review of CSAPR. If reinstated, we do not believe CSAPR will have a material effect on our operations, but **DP&L** is unable to estimate the affect of any replacement requirements, if promulgated, in future years.

- **Climate Change Legislation and Regulation**

  On June 25, 2013, the President of the United States directed the USEPA to issue a new proposed rule establishing New Source Performance Standards for CO_2 emissions for newly constructed fossil-fueled EGUs larger than 25 MW by September 2013, and to issue a final rule in a timely fashion after considering all public comments. The USEPA issued such new proposed rule in September 2013. The proposed rule anticipates that newly constructed fossil-fueled power plants generally would need to rely upon partial implementation of carbon capture and storage technology or other pollution control technology to meet the standard.

  In his June 25, 2013 announcement, the President, as anticipated, also directed the USEPA to issue new standards, regulations, or guidelines, as appropriate, that address CO_2 emissions from existing power plants. The President directed the USEPA to (i) issue a proposed rule by June 1, 2014; (ii) issue a final rule by June 1, 2015; and (iii) require that States submit their implementation plans to the USEPA by no later than June 30, 2016. Following this announcement, in September 2013, 18 states, including Ohio, sent the USEPA a white paper questioning the USEPA's legal authority to impose CO_2 emission standards on existing power plants. It is too soon to determine whether any such standards would materially impact **DP&L's** operations.

  It is impossible to estimate the impact and compliance costs associated with any future USEPA GHG regulations applicable to new, modified or existing EGUs until such regulations are finalized; however, the impact, including the compliance costs, could be material to our consolidated financial condition or results of operations.

- **SB 221 Requirements**

  SB 221 and the implementation rules contain targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards. The standards require that, by the year 2025, 25% of the total number of kWh of electricity sold by the utility to retail electric consumers must come from alternative energy resources, which include "advanced energy resources" such as distributed generation, clean coal, advanced nuclear, energy efficiency and fuel cell technology; and "renewable energy resources" such as solar, hydro, wind, geothermal and biomass. At least half of the 25% must be generated from renewable energy resources, including 0.5% from solar energy. The renewable energy portfolio, energy efficiency and demand reduction standards began in 2009 with increased percentage requirements each year thereafter. The annual targets for energy efficiency and peak demand reductions began in 2009 with annual increases. Energy efficiency programs are to save 22.3% by 2025 and peak demand reductions are expected to reach 7.75% by 2018 compared to a baseline energy usage. If any targets are not met, compliance penalties will apply, unless the PUCO makes certain findings that would excuse performance.

  SB 221 also contains provisions for determining whether an electric utility has significantly excessive earnings. The PUCO issued general rules for calculating the earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings. Pursuant to the ESP Stipulation, **DP&L** was subject to the SEET in 2013 based on 2012 earnings results, which did not have a material impact. Through the ESP Order the PUCO established **DP&L's** ROE SEET threshold at 12%. In future years, the SEET could have a material effect on our results of operations, financial condition and cash flows.

  SB 221 also requires that all Ohio distribution utilities file either an ESP or MRO. Under the MRO, a periodic competitive bid process will set the retail generation price after the utility demonstrates that it can meet certain market criteria and bid requirements. Also, under this option, utilities that still own generation in the state are required to phase-in the MRO over a period of not less than five years. An ESP may allow for adjustments to the SSO for costs associated with environmental compliance; fuel and purchased power; construction of new or investment in specified generating facilities; and the provision of standby and default service, operating, maintenance, or other costs including taxes. As part of its ESP, a utility is permitted to file an infrastructure improvement plan that will specify the initiatives the utility will take to rebuild, upgrade, or replace its electric distribution system, including cost recovery mechanisms. Both the MRO and ESP options involve a SEET based on the earnings of comparable companies with similar business and financial risks.

  On October 5, 2012, **DP&L** filed an ESP with the PUCO which was to be effective January 1, 2013. The plan was refiled to correct certain costs on December 12, 2012. The refiled plan requested approval of a non-bypassable charge that is designed to recover $137.5 million per year for five years from all customers. The ESP proposed a three-year, five-month transition to market, whereby a wholesale competitive bidding structure would be phased in to supply generation service to customers located in **DP&L's** service territory that have not chosen an alternative generation supplier. An evidentiary hearing on this case was held March 18, 2013 through April 3, 2013. An order was issued by the PUCO on September 4, 2013, and a correction to that order was issued on September 6, 2013 (ESP Order).

The ESP Order stated that **DP&L's** next ESP begins January 2014 and extends through May 31, 2017. The PUCO authorized **DP&L** to collect a non-bypassable Service Stability Rider (SSR) equal to $110 million per year for 2014 – 2016. **DP&L** has the opportunity to seek an additional $45.8 million through extension of the SSR through May 31, 2017, provided **DP&L** meets certain regulatory filing obligations, which include but are not limited to filing a plan by December 31, 2013 to separate the generation assets from the utility (as noted below, **DP&L** filed this on December 30, 2013) and filing a distribution rate case no later than July 1, 2014. The ESP Order also directs **DP&L** to divest its generation assets no later than May 31, 2017 and sets **DP&L's** SEET threshold at a 12% ROE. Beginning in 2014, **DP&L** will no longer be permitted to supply 100% of the generation service to its SSO customers. Instead, the PUCO directed **DP&L** to phase-in the competitive bidding structure with 10% of **DP&L's** SSO load sourced through the competitive bid starting in 2014, 40% in 2015, 70% in 2016 and 100% beginning June 1, 2017. The ESP Order approved **DP&L's** rate proposal to bifurcate its transmission charges into a non-bypassable component, TCRR-N, and a bypassable component, TCRR-B. The ESP order also required **DP&L** to establish a $2.0 million per year shareholder funded economic development fund.

Applications for rehearing were filed on October 4, 2013 by **DP&L** and other parties and are currently pending PUCO action. On October 23, 2013, the PUCO issued an entry on rehearing denying applications for rehearing that related to the competitive bid. The PUCO reaffirmed its position that economic development load should be included in the competitive bid auction and that **DP&L** affiliates are permitted to bid in the auction.

- **Legal separation of DP&L's generating facilities**

  DP&L filed a generation separation application at the end of December 2013, as required in its ESP order, with the PUCO and on February 25, 2014, filed a supplemental application. In the supplemental application, **DP&L** reaffirmed its commitment to separate the generation assets on or before May 31, 2017. **DP&L** continues to look at multiple options to effectuate the separation including the transfer to an unregulated affiliate or through a sale process. Assuming a transfer to an affiliate, we have requested the ability for the **DP&L** to, among other things: (a) maintain the greater of, (i) total debt of up to $750 million; or (ii) total debt equal to 75% of ratebase; (b) transfer the assets at a fair market value; and (c) keep OVEC as part of the utility post separation.

COMPETITION AND PJM PRICING

- **RPM Capacity Auction Price**

  The PJM RPM capacity base residual auction for the 2016/17 period cleared at a price of $59/MW-day for our RTO area. The per megawatt prices for the periods 2015/16, 2014/15, and 2013/14 were $136/MW-day, $126/MW-day, and $28/MW-day, respectively, based on previous auctions. Future RPM auction results will be dependent not only on the overall supply and demand of generation and load, but may also be impacted by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions. The SSO retail costs and revenues are included in the RPM rider. Therefore increases in customer switching causes more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. We cannot predict the outcome of future auctions or customer switching but based on actual results attained in 2013, we estimate that a hypothetical increase or decrease of $10 in the capacity auction price would affect net income by approximately $6.3 million and $5.0 million for **DPL** and **DP&L**, respectively. These estimates do not, however, take into consideration the other factors that may affect the impact of capacity revenues and costs on net income such as the levels of customer switching, our generation capacity, the levels of wholesale revenues and our retail customer load. These estimates are discussed further within Commodity Pricing Risk under the Market Risk section of this Management Discussion & Analysis.

- **Ohio Competitive Considerations and Proceedings**

  Since January 2001, **DP&L's** electric customers have been permitted to choose their retail electric generation supplier. **DP&L** continues to have the exclusive right to provide delivery service in its state certified territory and the obligation to supply retail generation service to customers that do not choose an alternative supplier. The PUCO maintains jurisdiction over **DP&L's** delivery of electricity, SSO and other retail electric services.

Lower market prices for power have resulted in increased levels of competition to provide retail generation services. This in turn has led approximately 67% of **DP&L's** customers to switch their retail electric services to CRES providers. DPLER, an affiliated company and one of the registered CRES providers, has been marketing generation services to **DP&L** customers. The following table provides a summary of the number of electric customers and volumes provided by all CRES providers in our service territory during the years ended December 31, 2013, 2012 and 2011:

	Year ended December 31, 2013		**Year ended December 31, 2012**		**Year ended December 31, 2011**	
	Electric Customers	Sales (in millions of kWh)	Electric Customers	Sales (in millions of kWh)	Electric Customers	Sales (in millions of kWh)
Supplied by DPLER	130,303	5,874	73,672	6,201	36,667	5,731
Supplied by non-affiliated CRES providers	87,951	3,471	79,936	1,981	27,812	862
Total supplied in our service territory	218,254	9,345	153,608	8,182	64,479	6,593
Supplied by DP&L in our service territory (a)	514,926	13,877	513,266	13,999	513,381	14,022

(a) The kWh sales include all distribution sales, including those whose power is supplied by DPLER and non-affiliated CRES providers.

The volumes supplied by DPLER represent approximately 42%, 44% and 41% of **DP&L's** total distribution volumes during the years ended December 31, 2013, 2012 and 2011, respectively. We currently cannot determine the extent to which customer switching to CRES providers will occur in the future and the effect this will have on our operations, but any additional switching could have a significant adverse effect on our future results of operations, financial condition and cash flows.

For the year ended December 31, 2013, approximately 67% of **DP&L's** load was supplied by CRES providers with DPLER supplying 63% of the switched load. Customer switching negatively affected **DPL's** gross margin during the years ended December 31, 2013, 2012 and 2011 by approximately $248.4 million, $141.0 million and $58.0 million, respectively. Customer switching negatively affected **DP&L's** gross margin during the years ended December 31, 2013, 2012 and 2011 by approximately $318.3 million, $249.0 million and $104.0 million, respectively.

Several communities in **DP&L's** service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering retail generation service to their residents. To date, a number of communities have filed with the PUCO to initiate aggregation programs. If a number of the larger communities move forward with aggregation in **DP&L's** service area, it could have a material effect on our earnings. See Item 1A – Risk Factors for more information.

DPLER began providing CRES services to business customers in Ohio who are not in **DP&L's** service territory in 2010 and to residential customers in 2012. Additionally, beginning in March 2011 with the purchase of MC Squared, DPLER services business and residential customers in northern Illinois. The incremental costs and revenues have not had a material effect on our results of operations, financial condition or cash flows.

FUEL AND RELATED COSTS

- **Fuel and Commodity Prices**

The coal market is a global market in which domestic prices are affected by international supply disruptions and demand balance. In addition, domestic issues like government-imposed direct costs and permitting issues are affecting mining costs and supply availability. Our approach is to hedge the fuel costs for our anticipated electric sales. We have substantially all of the total expected coal volume needed to meet our retail and wholesale sales requirements for 2014 under contract. 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/forced outages and generation station mix. Due to the installation of emission controls equipment at certain commonly-owned units and barring any changes in the regulatory environment in which we operate, we expect to have balanced positions for SO_2, NO_x and renewable energy credits for 2014. If our suppliers do not meet their contractual commitments or we are not hedged against price volatility and we are unable to recover costs through the fuel and purchased power recovery rider, our results of operations, financial condition or cash flows could be materially affected.

Effective January 2010, fuel price changes, including coal requirements and purchased power costs, associated with SSO load was reflected in the implementation of the fuel and purchased power recovery rider, subject to PUCO review. An audit of 2012 fuel costs occurred in 2013. On June 12, 2013, we received a report from the external auditor recommending a pre-tax disallowance of $5.3 million of costs. Hearings in this case were held on December 9-10, 2013 and we expect an order in the case in the second quarter of 2014.

FINANCIAL OVERVIEW

In the Management's Discussion and Analysis of Results of Operations and Financial Condition, we have included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such combined presentation is considered to be a non-GAAP disclosure. We have included such disclosure because we believe it facilitates the comparison of 2013 operating and financial performance to 2012 and 2011, and because the core operations of **DPL** have not changed as a result of the Merger.

The results of operations for both **DPL** and **DP&L** are separately discussed in more detail in the following pages.

The following table summarizes the significant components of **DPL's** Results of Operations for the years ended December 31, 2013, 2012 and 2011 (Combined):

	Successor		**Combined**	**Successor**	**Predecessor**
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Total operating revenues	**$ 1,636.9**	$ 1,668.4	$ 1,827.8	$ 156.9	$ 1,670.9
Cost of revenues:					
Fuel	**366.7**	361.9	391.6	35.8	355.8
Purchased power	**389.0**	342.1	441.3	36.7	404.6
Amortization of intangibles	**7.1**	95.1	11.6	11.6	-
Total cost of revenues	**762.8**	799.1	844.5	84.1	760.4
Total gross margin [(a)]	**874.1**	869.3	983.3	72.8	910.5
Operating expenses:					
Operation and maintenance	**396.7**	406.4	425.3	47.5	377.8
Depreciation and amortization	**132.9**	125.4	141.0	11.6	129.4
General taxes	**80.9**	79.5	83.1	7.6	75.5
Goodwill impairment	**306.3**	1,817.2	-	-	-
Fixed-asset impairment	**26.2**		-	-	-
Total operating expenses	**943.0**	2,428.5	649.4	66.7	582.7
Operating income / (loss)	**(68.9)**	(1,559.2)	333.9	6.1	327.8
Investment income / (loss), net	**1.4**	2.5	0.5	0.1	0.4
Interest expense	**(124.0)**	(122.9)	(70.2)	(11.5)	(58.7)
Charge for early redemption of debt	**(2.8)**		(15.3)		(15.3)
Other expense, net	**(5.4)**	(2.5)	(2.0)	(0.3)	(1.7)
Income / (loss) before income taxes	**(199.7)**	(1,682.1)	246.9	(5.6)	252.5
Income taxes	**22.3**	47.7	102.6	0.6	102.0
Net income / (loss)	**$ (222.0)**	$ (1,729.8)	$ 144.3	$ (6.2)	$ 150.5

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

RESULTS OF OPERATIONS – DPL Inc.

DPL's results of operations include the results of its subsidiaries, including the consolidated results of its principal subsidiary **DP&L**. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for **DP&L** is presented elsewhere in this report.

In the Management's Discussion and Analysis of Results of Operations and Financial Condition, we have included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such combined presentation is considered to be a non-GAAP disclosure. We have included such disclosure because we believe it facilitates the comparison of 2013 and 2012 operating and financial performance to 2011, and because the core operations of **DPL** have not changed as a result of the Merger.

Income Statement Highlights – DPL

	Successor		Combined	Successor	Predecessor
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Revenues:					
Retail	$ **1,297.2**	$ 1,391.2	$ 1,429.0	$ 126.3	$ 1,302.7
Wholesale	**229.7**	104.5	129.7	8.4	121.3
RTO revenue	**77.9**	92.2	81.7	6.6	75.1
RTO capacity revenues	**28.7**	74.5	179.7	13.9	165.8
Other revenues	**10.6**	11.0	10.8	0.9	9.9
Mark-to-market gains / (losses) [(a)]	**(7.2)**	(5.0)	(3.1)	0.8	(3.9)
Total revenues	**1,636.9**	1,668.4	1,827.8	156.9	1,670.9
Cost of revenues:					
Fuel	**366.0**	358.6	381.2	34.8	346.4
Losses / (gains) from sale of coal	**0.7**	11.8	(8.8)	(0.6)	(8.2)
Mark-to-market losses / (gains)	**-**	(8.5)	19.2	1.6	17.6
Net fuel cost	**366.7**	361.9	391.6	35.8	355.8
Purchased power:					
Purchased power	**243.9**	181.7	156.2	12.9	143.3
RTO charges	**111.9**	101.5	115.1	9.2	105.9
RTO capacity charges	**34.1**	68.1	172.9	13.1	159.8
Mark-to-market losses / (gains)	**(0.9)**	(9.2)	(2.9)	1.5	(4.4)
Net purchased power	**389.0**	342.1	441.3	36.7	404.6
Amortization of intangibles	**7.1**	95.1	11.6	11.6	-
Total cost of revenues	**762.8**	799.1	844.5	84.1	760.4
Gross margins [(b)]	$ **874.1**	$ 869.3	$ 983.3	$ 72.8	$ 910.5
Gross margins as a % of revenue	**53%**	52%	54%	46%	54%
Operating income / (loss)	$ **(68.9)**	$ (1,559.2)	$ 333.9	$ 6.1	$ 327.8

(a) For the years ended December 31, 2013 and 2012, this amount includes $7.2 million and $5.1 million, respectively, related to the amortization of asset balances related to retail power contracts that were previously accounted for as derivatives, but in accordance with ASC 815 are no longer derivatives. The fair value of these contracts is to be amortized to earnings over the remaining term of the associated agreements. A similar situation did not exist in periods prior to the year ended December 31, 2012.

(b) 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.

DPL – Revenues

Retail customers, especially residential and commercial customers, consume more electricity on warmer and colder days. Therefore, our retail sales volume is affected by the number of heating and cooling degree days occurring during a year. Cooling degree days typically have a more significant effect than heating degree days since some residential customers do not use electricity to heat their homes.

Degree days

	Years ended December 31,		
Number of days	**2013**	2012	2011
Heating degree days [(a)]	**5,542**	4,752	5,368
Cooling degree days [(a)]	**1,062**	1,264	1,160

(a) Heating and cooling degree days are a measure of the relative heating or cooling required for a home or business. The heating degrees in a day are calculated as the difference of the average actual daily temperature below 65 degrees Fahrenheit. For example, if the average temperature on March 20th was 40 degrees Fahrenheit, the heating degrees for that day would be the 25 degree difference between 65 degrees and 40 degrees. In a similar manner, cooling degrees in a day are the difference of the average actual daily temperature in excess of 65 degrees Fahrenheit.

Since we plan to utilize our internal generating capacity to supply our retail customers' needs first, increases in retail demand may decrease the volume of internal generation available to be sold in the wholesale market and vice versa. The wholesale market covers a multi-state area and settles on an hourly basis throughout the year. Factors affecting our wholesale sales volume each hour of the year include: wholesale market prices; our retail demand; retail demand elsewhere throughout the entire wholesale market area; our stations' and other utility stations' availability to sell into the wholesale market; and weather conditions across the multi-state region. Our plan is to make wholesale sales when market prices allow for the economic operation of our generation facilities not being utilized to meet our retail demand or when margin opportunities exist between the wholesale sales and power purchase prices.

The following table provides a summary of changes in revenues from prior periods:

$ in millions	**2013 vs. 2012**	2012 vs. 2011
Retail		
Rate	$ **(70.0)**	$ (37.8)
Volume	**(33.3)**	2.5
Other	**9.3**	(2.5)
Total retail change	**(94.0)**	(37.8)
Wholesale		
Rate	**(8.5)**	(27.8)
Volume	**133.7**	2.6
Total wholesale change	**125.2**	(25.2)
RTO capacity and other		
RTO capacity and other	**(60.1)**	(94.7)
Other		
Unrealized MTM	**(2.2)**	(1.9)
Other	**(0.4)**	0.2
Total revenue changes	$ **(31.5)**	$ (159.4)

During the year ended December 31, 2013, Revenues decreased $31.5 million, or 2%, to $1,636.9 million from $1,668.4 million in the same period of the prior year. This decrease was primarily the result of lower retail and wholesale average rates, lower retail volumes, decreased RTO capacity revenues and increased unrealized MTM losses, partially offset by higher wholesale sales volumes. The revenue components for the year ended December 31, 2013 compared to 2012 are further discussed below:

- Retail revenues decreased $94.0 million primarily due to decreased prices driven by customer switching from competition to provide transmission and generation services in our service territory. The **DP&L** sales volume decreased 13% from the prior year; however, the effect of sales procured by DPLER and MC Squared outside our service territory, or off-system sales, offset volume decreases resulting in an overall 1% increase in total **DPL** sales volume. The rates offered to the off-system customers are lower than the rates in our service territory causing an overall 8% decrease in average rates. There was a 16% decrease in cooling degree days to 1,062 from 1,264 in 2012, as well as a 17% increase in the number of heating degree days to 5,542 days from 4,752 days in 2012, therefore weather had a minimal impact. The above resulted in an unfavorable $70.0 million retail price variance and an unfavorable $33.3 million retail sales volume variance, partially offset by a $7.0 million shared savings accrual related to **DP&L** energy efficiency programs.
- Wholesale revenues increased $125.2 million primarily as a result of a 128% increase in wholesale sales volume due to customer switching, which makes our generation available for wholesale sales, including a 16% increase in total net generation by our power plants, offset slightly by a 3.6% decrease in average wholesale prices. This resulted in a favorable $133.7 million wholesale sales volume variance partially offset by an unfavorable wholesale price variance of $8.5 million.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $60.1 million. This decrease in RTO capacity and other revenues was the result of a $45.8 million decrease in revenues realized from the PJM capacity auction, and a $12.8 million decrease in RTO transmission and congestion revenues due to a 2012 settlement related to PJM SECA revenues and $7 million energy efficiency credits.

During the year ended December 31, 2012, Revenues decreased $159.4 million, or 9%, to $1,668.4 million from $1,827.8 million in the same period of the prior year. This decrease was primarily the result of decreased retail and wholesale average rates, decreased RTO capacity and other revenues, offset by increased retail and wholesale volume. The revenue components for the year ended December 31, 2012 compared to 2011 are further discussed below:

- Retail revenues decreased $37.8 million primarily due to a 3% decrease in average retail rates. The decrease is the result of customers switching from **DP&L** to DPLER, an affiliated CRES provider. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to DPLER, **DP&L** continued to provide distribution services to those customers within its service territory. The remaining distribution services provided by **DP&L** were billed at a lower average rate resulting in a reduction of total average retail rates. The effect of sales procured by DPLER and MC Squared outside our service territory, or off-system sales, caused sales volume to slightly increase by 0.2%; however the rates offered to the off-system customers are lower than the average rates in our service territory. Weather also contributed to the relatively even volumes; cooling degree days increased 9% and heating degree days decreased 11% from prior year, however, cooling degree days have more of an impact on electricity usage than heating degree days due to the non-heat residential customer mix. The above resulted in an unfavorable $37.8 million retail sales rate variance offset slightly by a favorable $2.5 million retail volume variance.
- Wholesale revenues decreased $25.2 million primarily as a result of a 21% decrease in average wholesale prices. The decrease was slightly offset by a 2% increase in wholesale volume. This resulted in an unfavorable $27.8 million wholesale price variance partially offset by a favorable wholesale volume variance of $2.6 million.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $94.7 million compared to 2011. This decrease in RTO capacity and other revenues was primarily the result of a $105.2 million decrease in revenues realized from the PJM capacity auction and a decrease of $2.3 million in transmission, congestion and other revenues, offset by the receipt of $12.8 million of revenue recognized as a result of the SECA settlement.

DPL – Cost of Revenues
During the year ended December 31, 2013:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, increased $4.8 million, or 1%, compared to 2012, primarily due to increased fuel costs and decreased mark-to-market gains partially offset by decreased losses from the sale of coal. There was a 16% increase in the volume of generation at our stations and no fuel related mark-to-market gains or losses in 2013 compared to $8.5 million of gains in 2012. Partially offsetting these increases were $0.7 million in realized losses from the sale of coal in 2013, compared to $11.8 million of realized losses from the same period in 2012.
- Net purchased power increased $46.9 million, or 14%, compared to the same period in 2012 due largely to increased purchased power costs of $62.2 million, $48.3 million due to increased volume and $13.8 million due to higher average market prices for purchased power. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities. Partially offsetting these increases were decreased RTO capacity and other charges of $23.6 million which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. RTO capacity prices are set by an annual auction. This decrease also includes the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges.
- Amortization of intangibles decreased in 2013 compared to 2012 primarily due to the full amortization of the ESP during 2012.

During the year ended December 31, 2012:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $29.7 million, or 8%, compared to 2011, primarily due to increased mark-to-market gains on coal contracts and decreased fuel costs partially offset by increased losses from the sale of coal. During the year ended December 31, 2012, there was a 10% decrease in the volume of generation at our stations and mark-to-market gains were $8.5 million compared to $19.2 million of mark-to-market losses for the same period during 2011. Offsetting these decreases were $11.8 million in realized losses from the sale of coal, compared to $8.8 million of realized gains during the same period in 2011.
- Net purchased power decreased $99.2 million, or 22%, compared to the same period in 2011 due largely to decreased RTO capacity and other charges of $118.4 million which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. RTO capacity prices are set by an annual auction. This decrease also includes the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Partially offsetting these decreases were increased purchased power costs of $25.5 million, $75.8 million due to increased volume offset by a decrease of $50.3 million due to lower average market prices for purchased power. Purchased power volume increased due to lower internal generation and increased off-system sales. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.
- Amortization of intangibles increased in 2012 compared to 2011 due to eleven months of amortization of the ESP during 2012.

DPL - Operation and Maintenance

$ in millions		2013 vs. 2012
Generating facilities operating and maintenance expenses	$	(19.9)
Low-income payment program [(a)]		(3.8)
Pension		(1.4)
Competitive retail operations		13.3
Health insurance		3.0
Other, net		(0.9)
Total operation and maintenance expense	$	(9.7)

(a) There is a corresponding increase in Revenues associated with these programs resulting in no impact to Net income.

During the year ended December 31, 2013, Operation and maintenance expense decreased $9.7 million, or 2%, compared to the same period in 2012. This variance was primarily the result of:

- decreased expenses for generating facilities largely due to outages related to maintenance activities in the first and second quarters of 2012 at jointly owned production units relative to the same periods in 2013;
- decreased expense associated with the USF revenue rate rider, which provides assistance to low-income retail customers; and
- lower pension expenses primarily related to changes in plan assumptions, specifically a higher discount rate.

These decreases were partially offset by:

- increased marketing, customer maintenance and labor costs associated with the competitive retail business as a result of increased sales volume and number of customers; and
- increased health insurance due to cost increases as well as more employees going on to long-term disability as compared to the same period in 2013.

$ in millions		2012 vs. 2011
Merger-related costs	$	(51.7)
Maintenance of overhead transmission and distribution lines		(10.2)
Low-income payment program (a)		21.3
Competitive retail operations		9.3
Energy efficiency programs (a)		9.2
Generating facilities operating and maintenance expenses		5.8
Legal and other consulting costs		3.0
Other, net		(5.6)
Total operation and maintenance expense	**$**	**(18.9)**

(a) There is a corresponding increase in Revenues associated with this program resulting in no impact to Net income.

During the year ended December 31, 2012, Operation and maintenance expense decreased $18.9 million, or 4%, compared to the same period in 2011. This variance was primarily the result of:

- higher costs in the prior year related to the Merger; and
- decreased expense related to the maintenance of overhead transmission and distribution lines primarily as a result of storms, including a significant ice storm in February 2011.

These decreases were partially offset by:

- increased expense associated with the USF revenue rate rider, which provides assistance for low-income retail customers;
- increased marketing, customer maintenance and labor costs associated with the competitive retail business as a result of increased sales volume and number of customers;
- increased expenses relating to energy efficiency programs that were put in place for our customers;
- increased expenses for generating facilities largely due to the length and timing of planned outages at jointly-owned production units relative to the same period in 2011; and
- increased expenses related to legal and other consulting services that were not related to the 2011 Merger.

DPL – Depreciation and Amortization

During the year ended December 31, 2013, Depreciation and amortization expense increased $7.5 million, or 6%, compared to 2012. The increase primarily reflects additional investments in fixed assets.

During the year ended December 31, 2012, Depreciation and amortization expense decreased $15.6 million, or 11%, compared to 2011. The decrease primarily reflects the effect of a reduction in electric generating station values as a consequence of the Merger, partially offset by additional investments in fixed assets.

DPL – General Taxes

During the year ended December 31, 2013, General taxes increased $1.4 million, or 2%, compared to 2012. This increase was primarily due to higher property tax accruals in 2013 compared to 2012 partially offset by a favorable determination of $1.6 million from the Ohio gross receipts tax appeal in 2013.

During the year ended December 31, 2012, General taxes decreased $3.6 million, or 4%, compared to 2011. This decrease was primarily due to an unfavorable determination of $4.5 million from the Ohio gross receipts tax audit in 2011 partially offset by higher property tax accruals in 2012 compared to 2011.

DPL – Goodwill Impairment

During the year ended December 31, 2013, **DPL** recorded an impairment of goodwill of $306.3 million. See Note 18 of Notes to **DPL's** Consolidated Financial Statements.

During the year ended December 31, 2012, **DPL** recorded an impairment of goodwill of $1,817.2 million. See Note 18 of Notes to **DPL's** Consolidated Financial Statements.

DPL – Interest Expense

During the year ended December 31, 2013, Interest expense and charge for early redemption of debt increased $1.1 million, or 1%, compared to 2012 due primarily to reduced amortization of debt premium (which offsets interest expense) partially offset by decreased interest due to reductions in debt and decreased interest rates on **DP&L's** senior secured bonds.

During the year ended December 31, 2012, Interest expense increased $37.4 million, or 44%, compared to 2011 due primarily to higher interest cost subsequent to the Merger as a result of the $1.25 billion of debt that was assumed by **DPL** in connection with the Merger.

DPL – Income Tax Expense

During the year ended December 31, 2013, Income tax expense decreased $25.4 million compared to 2012 primarily due to lower pre-tax income (excluding the effect of the goodwill impairment), a 2013 deferred tax adjustment related to the expiration of the statutes of limitation on the 2007, 2008 and 2009 tax years, an increase in the tax benefits of Internal Revenue Code Section 199 tax benefits in 2013 and a 2012 adjustment to state deferred taxes.

During the year ended December 31, 2012, Income tax expense decreased $54.9 million compared to 2011 primarily due to decreases in pre-tax income, lower non-deductible expenses related to the Merger, lower non-deductible compensation related to the Merger and a 2011 write-off 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.

RESULTS OF OPERATIONS BY SEGMENT – DPL Inc.

DPL's two segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its competitive retail electric service subsidiaries. These segments are discussed further below:

Utility Segment

The Utility segment is comprised of **DP&L's** electric generation, transmission and distribution businesses which generate and distribute electricity to residential, commercial, industrial and governmental customers. **DP&L** generates electricity at seven coal-fired power stations and distributes electricity to more than 515,000 retail customers who are located in a 6,000 square mile area of West Central Ohio. Beginning in 2014, **DP&L** is required to procure 10% of the power for SSO customers through a competitive bid process, with the percentage increasing each year, reaching 100% in June 2017. Further, in December 2013, **DP&L** filed a plan with the PUCO to sell or transfer its generation assets by May 31, 2017. **DP&L** also sells electricity to DPLER and any excess energy and capacity is sold into the wholesale market. **DP&L's** transmission and distribution businesses are subject to rate regulation by federal and state regulators while rates for its generation business are deemed competitive under Ohio law.

Competitive Retail Segment

The Competitive Retail segment is comprised of DPLER's competitive retail electric service business and includes its wholly-owned subsidiary, MC Squared. DPLER sells 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 308,000 customers currently located throughout Ohio and Illinois. MC Squared, a Chicago-based retail electricity supplier, serves approximately 144,000 customers in Northern Illinois and is a subsidiary of DPLER. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. Intercompany sales from **DP&L** to DPLER are based on the market prices for wholesale power. In periods prior to 2010, DPLER's purchases from **DP&L** are based on fixed-price contracts for each DPLER customer; the price approximates market prices for wholesale power at the inception of each customer's contract. The Competitive Retail segment has no transmission or generation assets. The operations of the Competitive Retail segment are not subject to cost-of-service rate regulation by federal or state regulators.

Other

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

Management evaluates segment performance based on gross margin. See Note 17 of Notes to **DPL's** Consolidated Financial Statements for further discussion of **DPL's** reportable segments.

The following table presents **DPL's** gross margin by business segment:

	Successor		Combined	Successor	Predecessor
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Utility	**$ 807.1**	$ 867.4	$ 895.5	$ 78.5	$ 817.0
Competitive Retail	**51.9**	68.6	61.5	4.8	56.7
Other	**18.7**	(63.3)	30.4	(10.1)	40.5
Adjustments and Eliminations	**(3.6)**	(3.4)	(4.1)	(0.4)	(3.7)
Total consolidated	**$ 874.1**	$ 869.3	$ 983.3	$ 72.8	$ 910.5

The financial condition, results of operations and cash flows of the Utility segment are identical in all material respects and for all periods presented to those of **DP&L** which are included in this Form 10-K. We do not believe that additional discussions of the financial condition and results of operations of the Utility segment would enhance an understanding of this business since these discussions are already included under the **DP&L** discussions below.

Income Statement Highlights – Competitive Retail Segment

$ in millions	Successor **Year ended December 31, 2013**	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
Revenues:					
Retail	**$ 518.8**	$ 496.7	$ 426.1	$ 37.1	$ 389.0
RTO and other	**(7.2)**	(3.6)	(0.7)	1.1	(1.8)
Total revenues	**511.6**	493.1	425.4	38.2	387.2
Cost of revenues:					
Purchased power	**459.7**	424.5	363.9	33.4	330.5
Gross margins [(a)]	**51.9**	68.6	61.5	4.8	56.7
Operation and maintenance expense	**38.0**	24.7	15.4	1.7	13.7
Other expense	**3.1**	3.0	2.5	0.3	2.2
Total expenses	**41.1**	27.7	17.9	2.0	15.9
Earnings from operations	**10.8**	40.9	43.6	2.8	40.8
Income tax expense	**4.2**	18.1	17.8	1.1	16.7
Net income	**$ 6.6**	$ 22.8	$ 25.8	$ 1.7	$ 24.1
Gross margin as a % of revenues	**10%**	14%	14%		

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

Competitive Retail Segment – Revenue

During the year ended December 31, 2013, the segment's retail revenues increased $22.1 million, or 4%, compared to 2012. The increase was primarily due to an $84.8 million positive volume variance primarily due to sales growth outside of **DP&L's** service territory in both Ohio and Illinois. The increased volume was partially offset by a $62.7 million negative price variance as increased competition in the competitive retail electric service business in the state of Ohio has resulted in decreased retail prices. The Competitive Retail segment sold approximately 9,733 million kWh of power to approximately 308,000 customers compared to approximately 8,315 million kWh of power to approximately 198,000 customers during the same period of the prior year.

During the year ended December 31, 2012, the segment's retail revenues increased $70.6 million, or 17%, compared to 2011. The increase was primarily driven by an increase of $37.5 million in the Illinois market primarily by approximately 100,000 additional customers obtained by MC Squared. Also contributing to the year-over-year increase was increased levels of competition in the competitive retail electric service business in the state of Ohio which in turn has resulted in a significant number of **DP&L's** retail customers switching their retail electric service to DPLER or other CRES providers. As a result of the additional customers and switching to DPLER discussed above, the Competitive Retail segment sold approximately 8,315 million kWh of power to 198,098 customers in 2012 compared to 6,677 million kWh of power to 40,171 customers during 2011.

Competitive Retail Segment – Purchased Power

During the year ended December 31, 2013, the Competitive Retail segment purchased power increased $35.2 million, or 8%, compared to 2012 primarily due to increased purchased power volumes required to satisfy an increase in customer base as described in the revenue section above. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L**. Intercompany sales from **DP&L** to DPLER and MC Squared are based on fixed-price contracts for each DPLER and MC Squared customer which approximate market prices for wholesale power at the inception of each customer's contract.

During the year ended December 31, 2012, the Competitive Retail segment purchased power increased $60.6 million, or 17%, compared to 2011 primarily due to higher purchased power volumes required to satisfy an increase in customer base resulting from customer switching and also $35.4 million relating to increased volumes in the Illinois market related to additional customers obtained by MC Squared. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. Beginning September 1, 2012, all of MC Squared's power needs are supplied by **DP&L**. Intercompany sales from **DP&L** to DPLER or its subsidiary MC Squared are based on fixed-price contracts for each customer which approximate market prices for wholesale power at the inception of each customer's contract.

Competitive Retail Segment – Operation and Maintenance

DPLER's operation and maintenance expenses include employee-related expenses, marketing, accounting, information technology, payroll, legal and other administration expenses. The higher operation and maintenance expense in 2013 compared to 2012 is reflective of increased marketing and customer maintenance costs associated with the increased sales volume and number of customers.

DPLER's operation and maintenance expenses include employee-related expenses, marketing, accounting, information technology, payroll, legal and other administration expenses. The higher operation and maintenance expense in 2012 compared to 2011 is reflective of increased marketing and customer maintenance costs associated with the increased sales volume and number of customers and the purchase of MC Squared.

RESULTS OF OPERATIONS – The Dayton Power and Light Company (DP&L)

Income Statement Highlights – DP&L

$ in millions	Years ended December 31, 2013	2012	2011
Revenues:			
Retail	$ **782.0**	$ 898.4	$ 1,007.4
Wholesale	**671.3**	483.7	441.2
RTO revenues	**74.5**	88.5	76.7
RTO capacity revenues	**24.0**	63.4	152.4
Mark-to-market gains / (losses)	**(0.3)**	(2.2)	-
Total revenues	**1,551.5**	1,531.8	1,677.7
Cost of revenues:			
Cost of fuel:			
Fuel	**361.8**	351.6	370.2
Losses / (gains) from sale of coal	**0.7**	11.8	(8.8)
Gains from sale of emission allowances	**-**	(0.1)	-
Mark-to-market (gains) / losses	**-**	(8.4)	19.2
Net fuel costs	**362.5**	354.9	380.6
Purchased power:			
Purchased power	**236.9**	151.6	121.5
RTO charges	**109.8**	98.8	114.9
RTO capacity charges	**33.9**	64.1	165.4
Mark-to-market (gains) / losses	**1.3**	(5.0)	(0.2)
Net purchased power	**381.9**	309.5	401.6
Total cost of revenues	**744.4**	664.4	782.2
Gross margins [(a)]	$ **807.1**	$ 867.4	$ 895.5
Gross margins as a % of revenues	**52%**	57%	53%
Operating income	$ **142.4**	$ 185.0	$ 319.9

(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.

DP&L – Revenues

The following table provides a summary of changes in **DP&L's** Revenues from prior periods:

	2013 vs. 2012	2012 vs. 2011
Retail		
Rate	$ (7.3)	$ (20.3)
Volume	(118.5)	(85.8)
Other	9.4	(2.9)
Total retail change	(116.4)	(109.0)
Wholesale		
Rate	(64.5)	(44.8)
Volume	252.1	87.3
Total wholesale change	187.6	42.5
RTO capacity and other		
RTO capacity and other revenues	(53.4)	(77.2)
Other		
Unrealized MTM	1.9	(2.2)
Total revenues change	$ 19.7	$ (145.9)

During the year ended December 31, 2013, revenues increased $19.7 million, or 1%, to $1,551.5 million from $1,531.8 million in the prior year. This increase was primarily the result of higher wholesale sales volumes. The revenue components for the year ended December 31, 2013 compared to 2012 are further discussed below:

- Retail revenues decreased $116.4 million primarily due to a 13% decrease in retail sales volumes compared to the prior year which was a result of customer switching due to increased levels of competition to provide transmission and generation services in our service territory. There was a 16% decrease in cooling degree days to 1,062 days from 1,264 days in 2012, as well as a 17% increase in the number of heating degree days to 5,542 days from 4,752 days in 2012, therefore weather had a minimal impact. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to CRES providers, **DP&L** continued to provide distribution services to those customers within its service territory. Average retail rates decreased slightly overall. The remaining distribution services provided by **DP&L** were billed at a lower average rate resulting in a slight reduction of total average retail rates. The above resulted in an unfavorable $118.5 million retail sales volume variance and an unfavorable $7.3 million retail price variance, partially offset by a $7.0 million shared savings accrual related to **DP&L** energy efficiency programs.
- Wholesale revenues increased $187.6 million as a result of an increase in wholesale sales volume which was largely a result of customer switching discussed in the immediately preceding paragraph. Customer switching in the **DP&L** service territory has resulted in increased generation available to sell in the wholesale market. Also contributing was a 17% increase in net generation available from **DP&L's** co-owned and operated generation plants. These increases were partially offset by a 9% decrease in average wholesale rates. These resulted in a favorable $252.1 million wholesale volume variance offset by a $64.5 million unfavorable wholesale price variance.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $53.4 million. This decrease in RTO capacity and other revenues was primarily the result of a $39.4 million decrease in revenues realized from the PJM capacity auction, and a $12.8 million decrease in RTO transmission and congestion revenues due to a 2012 settlement related to PJM SECA revenues.

During the year ended December 31, 2012, Revenues decreased $145.9 million, or 9%, to $1,531.8 million from $1,677.7 million in the prior year. This decrease was primarily the result of lower average retail rates, retail sales volumes and decreased RTO capacity and other revenues, partially offset by higher wholesale sales volumes and higher average wholesale prices. The revenue components for the year ended December 31, 2012 compared to 2011 are further discussed below:

- Retail revenues decreased $109.0 million primarily as a result of a 9% decrease in retail sales volumes compared to those in the prior year largely as a result of customer switching due to increased levels of competition to provide transmission and generation services in our service territory. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to DPLER, an affiliated CRES provider, **DP&L** continued to provide distribution services to those customers within its service territory, but these services are billed at a lower average rate causing a 2% decrease in retail rates. This decrease in sales volume was partially offset by improved economic conditions and warmer summer weather. The weather conditions resulted in a 9% increase in the number of cooling degree days to 1,264 from 1,160 days in 2011 offset slightly by an 11% decrease in the number of heating degree days to 4,752 days from 5,368 days in 2011. The decrease in average retail rates resulting from customers switching was partially offset by the fuel and energy efficiency riders, increased TCRR and RPM riders and the incremental effect of the recovery of costs under the EIR. The above resulted in an unfavorable $85.8 million retail sales volume variance and an unfavorable $20.3 million retail price variance.
- Wholesale revenues increased $42.5 million primarily as a result of a 20% increase in wholesale sales volume which was largely a result of the effect of customer switching discussed in the immediately preceding paragraph. **DP&L** records wholesale revenues from its sale of transmission and generation services to DPLER associated with these switched customers. This increase was partially offset by a 9% decrease in average wholesale rates. This resulted in a favorable $87.3 million wholesale volume variance offset by a $44.8 million unfavorable wholesale price variance.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $77.2 million compared to the same period in 2011. This decrease in RTO capacity and other revenues was primarily the result of an $89.0 million decrease in revenues realized from the PJM capacity auction and a decrease of $1.0 million in transmission and congestion revenues, offset by $12.8 million of revenue recognized as a result of the SECA settlement.

DP&L – Cost of Revenues

During the year ended December 31, 2013:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, increased $7.6 million, or 2%, compared to 2012, primarily due to increased fuel costs and decreased mark-to-market gains on coal contracts partially offset by decreased losses from the sale of coal. During the year ended December 31, 2013, there was a 17% increase in the volume of generation at our stations and no fuel related mark-to-market gains or losses compared to $8.4 million of gains in 2012. Partially offsetting these increases were $0.7 million in realized losses from the sale of coal, compared to $11.8 million of realized losses from the same period in 2012.
- Net purchased power increased $72.4 million, or 23%, compared to the same period in 2012 due largely to increased purchased power costs of $85.3 million, $74.0 million due to increased volume and an increase of $11.9 million due to higher average market prices for purchased power. Purchased power volume increased due to power purchased to supply increased off-system sales. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities. Partially offsetting these increases were decreased RTO capacity and other charges of $19.2 million which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. RTO capacity prices are set by an annual auction. This decrease also includes the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges.

During the year ended December 31, 2012:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $25.7 million, or 7%, compared to 2011, primarily due to increased mark-to-market gains on coal contracts and decreased fuel costs partially offset by increased losses from the sale of coal. During the year ended December 31, 2012, there was an 11% decrease in the volume of generation at our electric generating stations and mark-to-market gains were $8.4 million compared to $19.2 million of mark-to-market losses for the same period during 2011. Offsetting these decreases were $11.8 million in realized losses from the sale of coal, compared to $8.8 million of realized gains during the same period in 2011.
- Net purchased power decreased $92.1 million, or 23%, compared to the same period in 2011 due largely to decreased RTO capacity and other charges of $117.4 million which were incurred as a member of

PJM, including costs associated with **DP&L's** load obligations for retail customers. RTO capacity prices are set by an annual auction. This decrease also includes the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Partially offsetting these decreases were increased purchased power costs of $30.1 million, $83.5 million due to increased volume offset by $53.3 million due to lower average market prices for purchased power. Purchased power volume increased due to lower internal generation and increased power sales to DPLER and MC Squared. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.

DP&L – Operation and Maintenance

$ in millions		2013 vs. 2012
Generating facilities operating and maintenance expenses	$	(19.8)
Low-income payment program [(a)]		(3.8)
Pension		(2.2)
Health Insurance		3.0
Other, net		(1.0)
Total operation and maintenance expense	$	(23.8)

(a) There is a corresponding increase in Revenues associated with these programs resulting in no impact to Net income.

During the year ended December 31, 2013, Operation and maintenance expense decreased $23.8 million, or 6%, compared to 2012. This variance was primarily the result of:

- decreased expenses for generating facilities largely due to outages related to maintenance activities in the first and second quarters of 2012 at jointly owned production units relative to the same periods in 2013;
- decreased expense associated with the USF revenue rate rider, which provides assistance for low-income retail customers; and
- lower pension expenses primarily related to changes in plan assumptions, specifically a higher discount rate.

These decreases were partially offset by:

- increased health insurance due to cost increases as well as more employees going on long-term disability as compared to the same period in 2013.

$ in millions		2012 vs. 2011
Low-income payment program [(a)]	$	21.3
Energy efficiency programs [(a)]		9.2
Generating facilities operating and maintenance expenses		6.0
Pension		5.7
Legal and other consulting costs		3.1
Merger-related costs		(19.4)
Maintenance of overhead transmission and distribution lines		(10.2)
Other, net		5.4
Total operation and maintenance expense	$	21.1

(a) There is a corresponding increase in Revenues associated with these programs resulting in no impact to Net income.

During the year ended December 31, 2012, Operation and maintenance expense increased $21.1 million, or 6%, compared to 2011. This variance was primarily the result of:

- increased expense associated with the USF revenue rate rider, which provides assistance for low-income retail customers;
- increased expenses relating to energy efficiency programs that were put in place for our customers;

- increased expenses for generating facilities largely due to the length and timing of planned outages at jointly-owned production units relative to the same period in 2011;
- higher pension expenses primarily related to changes in plan assumptions, specifically a lower discount rate and lower expected rate of return on plan assets; and
- increased expenses related to legal and other consulting services that were not related to the Merger.

These increases were partially offset by:

- higher costs in the prior year related to the Merger; and
- decreased expense related to the maintenance of overhead transmission and distribution lines primarily as a result of storms, including a significant ice storm in February 2011.

DP&L – Depreciation and Amortization

During the year ended December 31, 2013, Depreciation and amortization expense decreased $1.1 million, or 1%, compared to 2012. The decrease primarily reflects the full-year effect of a reduction of approximately $1.8 million related to a decrease in plant values as a result of impairment in the value of certain electric generating stations in the third quarter of 2012, partially offset by investments in plant and equipment.

During the year ended December 31, 2012, Depreciation and amortization expense increased $6.4 million, or 5%, compared to 2011. The increase primarily reflects the effect of investments in plant and equipment, partially offset by a reduction of approximately $1.8 million related to a decrease in plant values as a result of impairment in the value of certain electric generating stations in the third quarter of 2012.

DP&L – General Taxes

During the year ended December 31, 2013, General taxes increased $2.0 million, or 3%, compared to 2012. This increase was primarily the result of higher property tax accruals in 2013 compared to 2012 partially offset by a favorable determination of $1.6 million from the Ohio gross receipts tax appeal in 2013.

During the year ended December 31, 2012, General taxes decreased $1.5 million, or 2%, compared to 2011. This decrease was primarily the result of lower payroll and Ohio commercial activity taxes in 2012 compared to 2011.

DP&L – Fixed-asset Impairment

During the year ended December 31, 2013, **DP&L** recorded an impairment of certain generation facilities of $86.0 million. See Note 15 of Notes to **DP&L's** Financial Statements.

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

During the year ended December 31, 2013, interest expense decreased $1.9 million or 5% compared to 2012 due to a reduction in outstanding debt and lower interest rates on **DP&L's** senior secured bonds.

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

DP&L – Income Tax Expense

During the year ended December 31, 2013, Income tax expense decreased $36.5 million compared to 2012 primarily due to decreases in pre-tax income, a 2013 deferred tax adjustment related to the expiration of the statutes of limitation on the 2007, 2008 and 2009 tax years and an increase in the tax benefits of Internal Revenue Code Section 199 tax benefits in 2013 and a 2012 adjustment to state deferred taxes.

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.

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, 2013**	Year ended December 31, 2012	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Net cash from operating activities	$ **302.8**	$ 291.5	$ 333.0	$ (1.4)	$ 334.4
Net cash from investing activities	**(123.9)**	(199.2)	(151.1)	(30.4)	(120.7)
Net cash from financing activities	**(317.8)**	(73.7)	(151.6)	88.9	(240.5)
Net change	**(138.9)**	18.6	30.3	57.1	(26.8)
Assumption of cash at acquisition	**-**	-	19.2	19.2	-
Cash and cash equivalents at beginning of period	**192.1**	173.5	124.0	97.2	124.0
Cash and cash equivalents at end of period	$ **53.2**	$ 192.1	$ 173.5	$ 173.5	$ 97.2

DP&L	Years ended December 31,		
$ in millions	**2013**	2012	2011
Net cash from operating activities	$ **335.3**	$ 339.8	$ 364.2
Net cash from investing activities	**(114.5)**	(197.5)	(185.0)
Net cash from financing activities	**(226.4)**	(146.0)	(201.0)
Net change	**(5.6)**	(3.7)	(21.8)
Cash and cash equivalents at beginning of period	**28.5**	32.2	54.0
Cash and cash equivalents at end of period	$ **22.9**	$ 28.5	$ 32.2

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, 2013, 2012 and 2011 are summarized as follows:

	Successor		Combined	Successor	Predecessor
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Net income / (loss)	**$ (222.0)**	$ (1,729.8)	$ 144.3	$ (6.2)	$ 150.5
Depreciation and amortization	**125.6**	201.5	152.6	23.2	129.4
Deferred income taxes	**24.0**	(4.2)	65.6	0.1	65.5
Impairment of Goodwill	**306.3**	1,817.2	-	-	-
Fixed Asset Impairment	**26.2**	-	-	-	-
Recognition of deferred SECA	**-**	(17.8)	-	-	-
Charge for early redemption of debt	**2.8**	-	15.3	-	15.3
Contribution to pension plan	**-**	-	(40.0)	-	(40.0)
Deferred regulatory assets, net	**7.6**	(1.1)	(14.3)	0.1	(14.4)
Cash settlement of interest rate hedges, net of tax	**-**	-	(31.3)	-	(31.3)
Other	**32.3**	25.7	40.8	(18.6)	59.4
Net cash from operating activities	**$ 302.8**	$ 291.5	$ 333.0	$ (1.4)	$ 334.4

During the year ended December 31, 2013, Net cash provided by operating activities was primarily a result of Net loss adjusted for the noncash impacts of depreciation and amortization, the impairment of goodwill and deferred income taxes.

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 to 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.

DP&L – Net Cash provided by Operating Activities
DP&L's Net cash provided by operating activities for the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

	Years ended December 31,		
$ in millions	***2013***	*2012*	*2011*
Net income	$ **83.6**	$ 91.2	$ 193.2
Depreciation and amortization	**140.2**	141.3	134.9
Deferred income taxes	**(16.8)**	3.6	50.7
Fixed asset impairment	**86.0**	80.8	-
Recognition of deferred SECA	**-**	(17.8)	-
Contribution to pension plan	**-**	-	(40.0)
Deferred regulatory assets, net	**7.8**	(1.5)	(12.6)
Other	**34.5**	42.2	38.0
Net cash from operating activities	$ **335.3**	$ 339.8	$ 364.2

During the year ended December 31, 2013 the significant components of **DP&L's** Net cash provided by operating activities were primarily the result of Net income adjusted for noncash depreciation and amortization, as well as the impairment of certain generation facilities.

During the year ended December 31, 2012 the significant components of **DP&L's** Net cash provided by operating activities were 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 year ended December 31, 2011, the significant components of **DP&L's** Net cash provided by operating activities are similar to those discussed under **DPL's** Net cash provided by operating activities above.

DPL – Net Cash used for Investing Activities
DPL's Net cash used for investing activities for the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

	Successor		**Combined**	**Successor**	**Predecessor**
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Environmental and renewable energy	$ **(2.4)**	$ (8.2)	$ (11.8)	$ -	$ (11.8)
Other plant-related asset acquisitions	**(122.0)**	(189.9)	(192.9)	(30.5)	(162.4)
Insurance proceeds	**7.6**	-	-	-	-
Purchase of MC Squared	**-**	-	(8.3)	-	(8.3)
Proceeds from sale of short-term investments	**-**	-	69.2	-	69.2
Other	**(7.1)**	(1.1)	(7.3)	0.1	(7.4)
Net cash from investing activities	$ **(123.9)**	$ (199.2)	$ (151.1)	$ (30.4)	$ (120.7)

During the year ended December 31, 2013, **DP&L's** environmental expenditures were primarily related to pollution control devices at our electric generation stations.

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 electric 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.

DP&L – Net Cash used for Investing Activities

DP&L's Net cash used for investing activities for the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

	Years ended December 31,		
$ in millions	**2013**	2012	2011
Environmental and renewable energy capital	$ **(2.4)**	$ (8.2)	$ (11.8)
Other plant-related asset acquisitions	**(119.7)**	(187.3)	(192.7)
Insurance proceeds	**14.2**	-	-
Proceeds from liquidation of **DPL** stock, held in trust	-	-	26.9
Other	**(6.6)**	(2.0)	(7.4)
Net cash from investing activities	$ **(114.5)**	$ (197.5)	$ (185.0)

During the year ended December 31, 2013, **DP&L's** environmental expenditures were primarily related to pollution control devices at our generation stations. In addition, **DP&L** received $14.2 million in insurance proceeds during the year, $6.6 million of which were from **DPL's** MVIC subsidiary.

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.

DPL – Net Cash used for Financing Activities

DPL's Net cash used for financing activities for the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

	Successor		**Combined**	**Successor**	**Predecessor**
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Dividends paid on common stock	$ **-**	$ (64.1)	$ (176.0)	$ (63.0)	$ (113.0)
Retirement of long-term debt	**(895.1)**	(0.1)	(297.5)	-	(297.5)
Early redemption of long-term debt	**(52.4)**	-	(134.2)	-	(134.2)
Payment of MC Squared debt	-	-	(13.5)	-	(13.5)
Repurchase of DPL common stock	-	-	-	-	-
Payment to former warrant holders	-	(9.0)	-	-	-
Issuance of long-term debt	**645.0**	-	425.0	125.0	300.0
Proceeds from liquidation of **DPL** stock,	-	-	26.9	26.9	-
Proceeds from exercise of warrants	-	-	14.7	-	14.7
Other	**(15.3)**	(0.5)	3.0	-	3.0
Net cash from financing activities	$ **(317.8)**	$ (73.7)	$ (151.6)	$ 88.9	$ (240.5)

During the year ended December 31, 2013, **DPL's** Net cash from financing activities primarily relates to debt issuance and redemption.

During the year ended December 31, 2012, **DPL's** Net cash from financing activities primarily relates 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.

DP&L – Net Cash used for Financing Activities

DP&L's Net cash used for financing activities for the years ended December 31, 2013, 2012 and 2011 are summarized as follows:

	Years ended December 31,		
$ in millions	**2013**	2012	2011
Dividends paid on common stock	$ **(190.0)**	$ (145.0)	$ (220.0)
Retirement of long-term debt	**(470.0)**	-	-
Issuance of long-term debt	**445.0**	-	-
Cash contribution from parent	-	-	20.0
Other	**(11.4)**	(1.0)	(1.0)
Net cash from financing activities	$ **(226.4)**	$ (146.0)	$ (201.0)

During the year ended December 31, 2013, **DP&L's** Net cash used for financing activities primarily relates to *$190 million in dividends and the issuance of new senior secured bonds, the proceeds of which were used to* redeem bonds at maturity.

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**.

Liquidity

We expect our existing sources of liquidity to remain sufficient to meet our anticipated operating needs. Our business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and carrying costs, potential margin requirements related to energy hedges, taxes and dividend payments. For 2014 and subsequent years, we expect to satisfy these requirements with a combination of cash from operations and funds from the debt financing as our internal liquidity needs and market conditions warrant. We also expect that the borrowing capacity under bank credit facilities will continue to be available to manage working capital requirements during those periods.

At the filing date of this annual report on Form 10-K, **DPL** and **DP&L** have access to the following revolving credit facilities:

$ in millions	Type	Maturity	Commitment	Amounts available as of December 31, 2013
DP&L	Revolving	May 2018	$ 300.0	$ 299.6
DPL	Revolving	May 2018	100.0	100.0
			$ 400.0	$ 399.6

DP&L's revolving credit facility, established in May 2013, expires in May 2018 and has nine participating banks, with no bank having more than 22.5% of the total commitment. This revolving credit facility has a $100.0 million letter of credit sublimit and **DP&L** also has the option to increase the potential borrowing amount under this facility by $100.0 million. **DP&L** had no outstanding borrowings under this facility at December 31, 2013. At December 31, 2013, there was a letter of credit in the amount of $0.4 million outstanding, with the remaining $299.6 million available to **DP&L**.

DPL's revolving credit facility was established in May 2013. This facility expires in May 2018; however, if **DPL** has not refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then this credit facility shall expire in July 2016. This facility has nine participating banks with no bank having more than 20% of the total commitment. **DPL's** revolving credit facility has a $100.0 million letter of credit sublimit and a feature which provides **DPL** the ability to increase the size of the facility by an additional $50.0 million. As of June 30, 2013, **DPL** had drawn $50.0 million under this facility. These outstanding borrowings were repaid in full on July 10, 2013 and as of December 31, 2013, there were no letters of credit issued and no outstanding borrowings against the revolving credit facilities.

Cash and cash equivalents for **DPL** and **DP&L** amounted to $53.2 million and $22.9 million, respectively, at December 31, 2013. At that date, neither **DPL** nor **DP&L** had short-term investments.

Capital Requirements

CONSTRUCTION ADDITIONS

	Actual			Projected		
$ in millions	2011	2012	2013	2014	2015	2016
DPL	$ 201	$ 180	$ 114	$ 136	$ 124	$ 133
DP&L	$ 199	$ 177	$ 111	$ 125	$ 116	$ 126

Planned construction additions for 2014 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 $- million in capital projects for the period 2014 through 2016. Approximately $5.0 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 $65.0 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

In May 2013 **DPL** terminated its then existing $75.0 million revolving credit facility and $425.0 million term loan and replaced them with a new $100.0 million revolving credit facility and a drawn $200.0 million term loan facility.

Each of the facilities that were terminated in May had two financial covenants. The first financial covenant was a Total Debt to EBITDA ratio. The new **DPL** revolving credit facility and the new **DPL** term loan agreement that were put in place in May 2013, will continue to have a Total Debt to EBITDA ratio that will be 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 in the new agreements is not to exceed 8.50 to 1.00 for the fiscal quarter ending June 30, 2013 through December 31, 2014; it then steps down to not exceed 8.00 to 1.00 for the fiscal quarter ending March 31, 2015 through December 31, 2016; and it then steps down not to exceed 7.50 to 1.00 for the fiscal quarter ending March 31, 2017 through March 31, 2018. As of December 31, 2013, the financial covenant was met with a ratio of 5.89 to 1.00.

The second financial covenant was an EBITDA to Interest Expense ratio. The new **DPL** revolving credit facility and the new **DPL** term loan agreement that were put in place in May 2013, will continue to have an EBITDA to Interest Expense ratio that 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, per the new agreements is not to be less than 2.00 to 1.00 for the fiscal quarter ending June 30, 2013 through December 31, 2014; it then steps up to not to be less than 2.10 to 1.00 for the fiscal quarter ending March 31, 2015 through December 31, 2016; and it then steps up to not to be less than 2.25 to 1.00 for the fiscal quarter ending March 31, 2017 through March 31, 2018. As of December 31, 2013, the financial covenant was met with a ratio of 3.09 to 1.00.

Both **DPL's** revolving credit facility and term loan that were terminated in May 2013 and **DPL's** new unsecured revolving credit agreement and new unsecured term loan both executed on May 10, 2013 restrict dividend payments from **DPL** to AES and adjust the cost of borrowing under the facilities under certain rating scenarios.

Also, in May 2013 **DP&L** terminated its two $200.0 million revolving credit facilities and replaced them with a new $300.0 million revolving credit facility. Each of the facilities that were terminated in May had a Total Debt to Total Capitalization financial covenant. **DP&L's** new revolving credit facility that was put in place in May 2013, also has a financial covenant that requires the Total Debt to Total Capitalization ratio to not exceed 0.65 to 1.00. As of December 31, 2013, this covenant was met with a ratio of 0.44 to 1.00. The above ratio is calculated as the sum of **DP&L's** current and long-term portion of debt, including its guarantee obligations, divided by the total of **DP&L's** shareholder's equity and total debt including guarantee obligations. In addition, the new **DP&L** revolving credit facility that was put in place in May 2013 has a second financial covenant that did not exist in the previous agreements. The second covenant is an EBITDA to Interest Expense ratio that will be 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. **DP&L's** EBITDA to Interest Expense ratio cannot be less than 2.50 to 1.00. As of December 31, 2013, this covenant was met with a ratio of 8.76 to 1.00.

Debt Ratings

On April 30, 2013 Standard & Poor's upgraded **DPL's** unsecured debt and maintained all other ratings and the Stable outlook. On September 9, 2013 and September 10, 2013, Moody's and Fitch, respectively, downgraded **DPL** and **DP&L** credit and debt ratings and updated their outlooks to Stable.

The following table outlines the debt ratings and outlook for **DPL** and **DP&L**, along with the effective dates of each rating.

	DPL *(a)*	**DP&L** *(b)*	Outlook	Effective
Fitch Ratings	BB	BBB	Stable	September 2013
Moody's Investors Service, Inc.	Ba2	Baa1	Stable	September 2013
Standard & Poor's Financial Services LLC	BB	BBB-	Stable	April 2013

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	B+	BB+	Stable	September 2013
Moody's Investors Service, Inc.	Ba2	Baa3	Stable	September 2013
Standard & Poor's Financial Services LLC	BB	BB	Stable	April 2013

On April 4, 2013 Standard and Poor's Ratings Services upgraded **DPL's** senior unsecured debt rating from BB- Stable to BB Stable and maintained **DPL's** Credit Rating (or Issuer Default Rating) at BB Stable. Standard and Poor's Ratings Services did not change **DP&L's** Credit Rating or Debt Rating in 2013.

On November 7, 2012, Fitch Ratings issued a new **DPL** issuer default 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 on this date, but the outlook on its issuer credit rating and **DP&L's** senior secured debt changed to "Rating Watch Negative". On September 10, 2013 Fitch resolved "Rating Watch Negative" by downgrading the **DPL** issuer default rating to B+ (from BB), affirming **DPL's** senior unsecured debt rating at BB, downgrading the **DP&L** issuer default rating to BB+ (from BBB-) and downgrading the **DP&L** senior secured rating to BBB (from BBB+). The outlooks of all **DP&L** and **DPL** ratings were changed to a Stable outlook.

On November 9, 2012, Moody's Investors Services, Inc. placed all the ratings of **DPL** and **DP&L** under review for possible downgrade. On September 9, 2013, Moody's resolved this negative outlook by downgrading the **DPL** issuer default rating to Ba2 (from Ba1), downgrading the **DPL** senior unsecured debt rating to Ba2 (from Ba1), downgrading the **DP&L** issuer default rating to Baa3 (from Baa2) and downgrading the **DP&L** senior secured rating to Baa1 (from A3). The outlooks of all **DP&L** and **DPL** ratings were changed to a Stable outlook.

The above mentioned changes 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 further, 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 one 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, 2013, **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, 2013, **DPL** had $25.9 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 $0.2 million at December 31, 2013 and $0.0 million at December 31, 2012.

DP&L owns a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. **DP&L** could be responsible for the repayment of 4.9%, or $76.4 million, of a $1,558.4 million debt obligation comprised of both fixed and variable rate securities with maturities between 2014 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2013, 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, 2013, 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	$ 2,298.4	$ 10.2	$ 955.2	$ 100.2	$ 1,232.8
Interest payments	944.0	114.9	229.5	151.5	448.1
Pension and postretirement payments	264.2	27.2	51.9	52.3	132.8
Operating leases	0.6	0.4	0.2	-	-
Coal contracts (a)	625.6	216.5	270.3	138.8	-
Limestone contracts (a)	24.4	6.1	12.2	6.1	-
Purchase orders and other contractual obligations	85.6	48.8	18.7	18.1	-
Total contractual obligations	$ 4,242.8	$ 424.1	$ 1,538.0	$ 467.0	$ 1,813.7

		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	$ 877.8	$ 0.2	$ 445.2	$ 0.2	$ 432.2
Interest payments	361.0	24.1	48.4	31.7	256.8
Pension and postretirement payments	264.5	27.2	51.9	52.3	133.1
Operating leases	0.6	0.4	0.2	-	-
Coal contracts (a)	625.6	216.5	270.3	138.8	-
Limestone contracts (a)	24.4	6.1	12.2	6.1	-
Purchase orders and other contractual obligations	85.6	48.8	18.7	18.1	-
Total contractual obligations	$ 2,239.5	$ 323.3	$ 846.9	$ 247.2	$ 822.1

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

Long-term debt:

DPL's Long-term debt as of December 31, 2013 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, 2013 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, 2013.

Pension and postemployment payments:

As of December 31, 2013, **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 2023.

Capital leases:
As of December 31, 2013, **DPL**, through its principal subsidiary **DP&L**, had one immaterial capital lease that expires in 2014.

Operating leases:
As of December 31, 2013, **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, 2013, **DPL** and **DP&L** had various other contractual obligations including non-cancelable contracts to purchase goods and services with various terms and expiration dates.

Reserve for uncertain tax positions:
Due to the uncertainty regarding the timing of future cash outflows associated with our unrecognized tax benefits of $8.8 million at December 31, 2013, we are unable to make a reliable estimate of the periods of cash settlement with the respective tax authorities and have not included such amounts in the contractual obligations table above.

MARKET RISK

We are subject to certain market risks including, but not limited to, changes in commodity prices for electricity, coal, environmental emission allowances, 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 2014 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. We are considered an end-user under the Dodd-Frank Act and therefore are exempt from most of the collateral and margining requirements. We are required to report our bilateral derivative contracts, unless our counterparty is a major swap participant or has elected to report on our behalf. Even though we 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, 2013 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, 2013 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)
2014- Net Purchase/(Sale) Position	0.8	$ 36.44	$ 1.9
2015- Net Purchase/(Sale) Position	(0.2)	$ 39.83	$ (0.5)
2016- Net Purchase/(Sale) Position	(0.3)	$ 38.07	$ (0.7)

Wholesale revenues
Approximately 16% of **DPL's** and 45% of **DP&L's** electric revenues for the year ended December 31, 2013 were from sales of excess energy and capacity in the wholesale market (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER). Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

Approximately 11% of **DPL's** and 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. 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 (net of an estimated income tax at 35%) as of December 31, 2013 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	$ 12.5	$ 14.1

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 2016/17 delivery year. The clearing prices for capacity during the PJM delivery periods from 2012/13 through 2016/17 are as follows:

($/MW-day)	PJM Delivery Year				
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Capacity clearing price	$ 16	$ 28	$ 126	$ 136	$ 59

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

	Calendar Year				
($/MW-day)	**2012**	**2013**	**2014**	**2015**	**2016**
Computed average capacity price	$ 55	$ 23	$ 85	$ 132	$ 91

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, 2013 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, 2013. As of December 31, 2013, approximately 28% 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	$ 6.3	$ 5.0

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, 2013, 2012 and 2011 were 45%, 39% and 37%, respectively. We have a significant portion of projected 2014 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 2014; 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 NO_x allowances for 2014 depending on NO_x 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 as well as requirement to supply an increasing percentage of SSO load through the competitive bid auction. 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 fuel and purchased power costs associated with supplying SSO load as part of the fuel rider approved by the PUCO. Since there has been an increase in customer switching, SSO customers currently represent approximately 28% of **DP&L's** total fuel costs. The table below provides the effect on annual Net income (net of an estimated income tax at 35%) as of December 31, 2013, of a hypothetical increase or decrease of 10% in the prices of fuel and purchased power, adjusted for the approximate 28% recovery:

$ in millions	DPL	DP&L
Effect of 10% change in fuel and purchased power	$ 28.6	$ 28.0

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 $190 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 hedged against interest rate fluctuations by entering into interest rate swap agreements to limit the interest rate exposure on the underlying financing. These interest rate swap agreements had mandatory settlement dates of September 30, 2013 and were being used to limit our exposure to changes in interest rates and the effect this could have on our future borrowing costs. On September 16, 2013 and immediately after the sale of **DP&L's** new $445 million of First Mortgage Bonds, **DP&L** settled all of the above mentioned swap agreements at a total net settlement of $0. As of December 31, 2013, we do not have any interest rate hedging agreements still in place.

The carrying value of **DPL's** debt was $2,294.4 million at December 31, 2013, 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, 2013 was $2,334.6 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,	Fair value at December 31,
$ in millions	2014	2015	2016	2017	2018	Thereafter	2013 (a)	2013
Long-term debt								
Variable-rate debt	$ 10.0	$ 40.0	$ 40.0	$ 40.0	$ 60.0	$ 100.0	$ 290.0	$ 290.0
Average interest rate	2.4%	2.4%	2.4%	2.4%	2.4%	0.1%		
Fixed-rate debt	$ 0.2	$ 0.1	$ 875.1	$ 0.1	$ 0.1	$ 1,132.8	2,008.4	2,044.6
Average interest rate	5.2%	4.2%	4.2%	4.2%	4.2%	6.5%		
Total							$ 2,298.4	$ 2,334.6

The carrying value of **DP&L's** debt was $877.1 million at December 31, 2013, 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, 2013 was $859.6 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,	Fair value at December 31,
$ in millions	2014	2015	2016	2017	2018	Thereafter	2013 (a)	2013
Long-term debt								
Variable-rate debt	$ -	$ -	$ -	$ -	$ -	$ 100.0	$ 100.0	$ 100.0
Average interest rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%		
Fixed-rate debt	$ 0.2	$ 0.1	$ 445.1	$ 0.1	$ 0.1	$ 332.2	777.8	759.6
Average interest rate	5.2%	4.2%	1.9%	4.2%	4.2%	4.8%		
Total							$ 877.8	$ 859.6

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, 2013 and 2012 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, 2013 and 2012, 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, 2013 (a)	Fair value at December 31, 2013	One Percent Interest Rate Risk	Carrying value at December 31, 2012 (a)	Fair value at December 31, 2012	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	$ 290.0	$ 290.0	$ 2.9	$ 525.0	$ 525.0	$ 5.3
Fixed-rate debt	2,004.4	2,044.6	20.4	2,084.9	2,182.1	21.8
Total	$ 2,294.4	$ 2,334.6	$ 23.3	$ 2,609.9	$ 2,707.1	$ 27.1

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

DP&L

$ in millions	Carrying value at December 31, 2013 (a)	Fair value at December 31, 2013	One Percent Interest Rate Risk	Carrying value at December 31, 2012 (a)	Fair value at December 31, 2012	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	$ 100.0	$ 100.0	$ 1.0	$ 100.0	$ 100.0	$ 1.0
Fixed-rate debt	777.1	759.6	7.6	803.1	826.9	8.3
Total	$ 877.1	$ 859.6	$ 8.6	$ 903.1	$ 926.9	$ 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** $2,044.6 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** $290.0 million variable-rate long-term debt outstanding as of December 31, 2013.

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** $759.6 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, 2013.

Equity Price Risk

As of December 31, 2013, approximately 19% of the defined benefit pension plan assets were comprised of investments in equity securities and 81% 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 $65.3 million at December 31, 2013. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $6.5 million reduction in fair value as of December 31, 2013 and approximately a $0.4 million increase to the 2014 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.

Goodwill Impairments
In the fourth quarter of 2013, **DPL** completed its annual October 1 goodwill impairment tests and recognized goodwill impairment expense of $306.3 million. The Company identified both the DP&L and DPLER reporting units as "at risk." A reporting unit is considered "at risk" when its fair value is not higher than its carrying amount by more than 10%. The Company monitors its reporting units at risk of step 1 failure on an ongoing basis. Since 2012, the DP&L reporting unit remains at risk subsequent to its goodwill impairments of $1,817.2 million recognized in 2012 and $306.3 million recognized in 2013. During the nine months ended September 30, 2013, the Company continued to monitor the business environment and regulatory developments. In the fourth quarter of 2013, the DP&L reporting unit recognized goodwill impairment expense of $306.3 million as part of its annual goodwill impairment test. It is possible that we may incur goodwill impairment at DP&L or DPLER reporting units in future periods if adverse changes in their business or operating environments occur. As of December 31, 2013, the DP&L and DPLER reporting units had goodwill of $317.0 million and $135.8 million, respectively. See Note 18 of Notes to **DPL's** Consolidated Financial Statements for more information on the impairment of Goodwill.

Critical Accounting Estimates

DPL's Consolidated Financial Statements and **DP&L's** Financial Statements are prepared in accordance with 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. See Note 18 of Notes to **DPL's** Consolidated Financial Statements discussing the impairment of goodwill at **DPL** in 2013 and 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. See Note 15 of Notes to **DP&L's** Financial Statements discussing the impairment of long-lived assets at **DP&L** in 2013 and 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 $6.7 million and $11.5 million at December 31, 2013 and 2012, 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 $18.8 million and $17.7 million for 2013 and 2012, 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 using certain assumptions. 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 postemployment benefits in accordance with the provisions of GAAP relating to the accounting for pension and other postemployment 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 2014, we are decreasing our long-term rate of return assumption from 7.00% to 6.75% for pension plan assets and we are maintaining 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 2014, we have increased our assumed discount rate to 4.86% from 4.04% for pension and to 4.58% from 3.75% for postemployment 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 2014 pension expense of approximately $3.4 million. A 25 basis point increase in the discount rate for pension would result in a decrease of approximately $0.3 million to 2014 pension expense. A 25 basis point decrease in the discount rate for pension would result in an increase of approximately $0.3 million to 2014 pension expense.

A one percent change in the rate of return assumption for pension would result in an increase or decrease to the 2014 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 2014 pension expense. A one percent decrease in the discount rate for pension would result in an increase of approximately $2.8 million to 2014 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, if any to the plans. We provide postemployment 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 postemployment 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 16 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.

FINANCIAL STATEMENTS

DPL INC.

Report of Independent Registered Public Accounting Firm

To the Board of Directors of DPL Inc. and subsidiaries

We have audited the accompanying consolidated balance sheets of DPL Inc. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of Results of Operations, Comprehensive Income/(Loss), Cash Flows, and Shareholders' Equity for the years ended December 31, 2013 and 2012 and the period from November 28, 2011 through December 31, 2011. Our audit also included the consolidated financial statement schedule "Schedule II – Valuation and Qualifying Accounts" for the years ended December 31, 2013 and 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 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 audits 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. and subsidiaries at December 31, 2013 and 2012, and the consolidated results of their operations and their cash flows for the years ended December 31, 2013 and 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
March 4, 2014
Louisville, Kentucky

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 of DPL Inc. and its subsidiaries (DPL) for the period from January 1, 2011 through November 27, 2011. In connection with our audit 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. These consolidated financial statements and consolidated financial statement schedule are the responsibility of DPL's management. Our responsibility is to express an opinion on these consolidated financial statements and consolidated financial statement 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 consolidated financial statements of DPL 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, 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/ KPMG LLP

Philadelphia, Pennsylvania
March 27, 2012

DPL INC.
CONSOLIDATED STATEMENTS OF RESULTS OF OPERATIONS

$ in millions except per share amounts	Successor: Year ended December 31, 2013	Successor: Year ended December 31, 2012	Successor: November 28, 2011 through December 31, 2011	Predecessor: January 1, 2011 through November 27, 2011
Revenues	**$ 1,636.9**	$ 1,668.4	$ 156.9	$ 1,670.9
Cost of revenues:				
Fuel	**366.7**	361.9	35.8	355.8
Purchased power	**389.0**	342.1	36.7	404.6
Amortization of intangibles	**7.1**	95.1	11.6	-
Total cost of revenues	**762.8**	799.1	84.1	760.4
Gross margin	**874.1**	869.3	72.8	910.5
Operating expenses:				
Operation and maintenance	**396.7**	406.4	47.5	377.8
Depreciation and amortization	**132.9**	125.4	11.6	129.4
General taxes	**80.9**	79.5	7.6	75.5
Goodwill impairment	**306.3**	1,817.2	-	-
Fixed asset impairment	**26.2**	-	-	-
Total operating expenses	**943.0**	2,428.5	66.7	582.7
Operating income / (loss)	**(68.9)**	(1,559.2)	6.1	327.8
Other income / (expense), net				
Investment income	**1.4**	2.5	0.1	0.4
Interest expense	**(124.0)**	(122.9)	(11.5)	(58.7)
Charge for early redemption of debt	**(2.8)**	-	-	(15.3)
Other deductions	**(5.4)**	(2.5)	(0.3)	(1.7)
Total other expense, net	**(130.8)**	(122.9)	(11.7)	(75.3)
Earnings (loss) from operations before income tax	**(199.7)**	(1,682.1)	(5.6)	252.5
Income tax expense	**22.3**	47.7	0.6	102.0
Net income / (loss)	**$ (222.0)**	$ (1,729.8)	$ (6.2)	$ 150.5
Average number of common shares outstanding (millions):				
Basic	**N/A**	N/A	N/A	114.5
Diluted	**N/A**	N/A	N/A	115.1
Earnings per share of common stock:				
Basic	**N/A**	N/A	N/A	$ 1.31
Diluted	**N/A**	N/A	N/A	$ 1.31
Dividends declared per share of common stock	**N/A**	N/A	N/A	$ 1.54

See Notes to Consolidated Financial Statements.

DPL INC.
STATEMENTS OF COMPREHENSIVE INCOME / (LOSS)

	Successor			Predecessor
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Net income / (loss)	$ **(222.0)**	$ (1,729.8)	$ (6.2)	$ 150.5
Available-for-sale securities activity:				
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $0.6, $(0.2), $0.0 and $0.0 for each respective period	**(1.2)**	0.5	-	-
Reclassification to earnings, net of income tax benefit / (expense) of $(0.7), $0.0, $0.0 and $0.0 for each respective period	**1.4**	(0.1)	-	-
Total change in fair value of available-for-sale	**0.2**	0.4	-	-
Derivative activity:				
Change in derivative fair value, net of income tax benefit / (expense) of $(10.6), $1.4, $0.3 and $31.2 for each respective period	**19.7**	(1.5)	(0.5)	(58.2)
Reclassification to earnings, net of income tax benefit / (expense) of $(2.3), $0.4, $0.0 and $(0.3) for each respective period	**3.4**	(0.5)	-	(0.3)
Total change in fair value of derivatives	**23.1**	(2.0)	(0.5)	(58.5)
Pension and postretirement activity:				
Prior service cost for the period, net of income tax benefit / (expense) of $0.0, $0.0, $0.2 and $0.0 for each respective period	**-**	-	(0.2)	0.1
Net loss for the period, net of income tax benefit / (expense) of $(2.7), $1.0, $(0.2) and $(0.7) for each respective period	**4.9**	(1.9)	0.3	0.3
Reclassification to earnings, net of income tax benefit / (expense) of $0.3, $0.0, $0.0 and $1.5 for each respective period	**0.3**	-	-	2.8
Total change in unfunded pension and postretirement	**5.2**	(1.9)	0.1	3.2
Other comprehensive income / (loss)	**28.5**	(3.5)	(0.4)	(55.3)
Net comprehensive income / (loss)	$ **(193.5)**	$ (1,733.3)	$ (6.6)	$ 95.2

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

$ in millions	Successor Year ended December 31, 2013	Successor Year ended December 31, 2012	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011
Cash flows from operating activities:				
Net income / (loss)	$ **(222.0)**	$ (1,729.8)	$ (6.2)	$ 150.5
Adjustments to reconcile Net income (loss) to Net cash from operating activities				
Depreciation and amortization	**132.9**	125.4	11.6	129.4
Amortization of intangibles	**7.1**	95.1	11.6	-
Amortization of debt market value adjustments	**(14.4)**	(19.0)	-	-
Deferred income taxes	**24.0**	(4.2)	0.1	65.5
Charge for early redemption of debt	**2.8**	-	-	15.3
Goodwill impairment	**306.3**	1,817.2	-	-
Fixed-asset impairment	**26.2**	-	-	-
Recognition of deferred SECA revenue	**-**	(17.8)	-	-
Changes in certain assets and liabilities:				
Accounts receivable	**7.4**	13.4	(12.3)	14.6
Inventories	**27.4**	15.6	(2.3)	(8.0)
Prepaid taxes	**0.7**	-	0.6	7.1
Taxes applicable to subsequent years	**(1.4)**	7.2	(71.2)	58.4
Deferred regulatory costs, net	**7.6**	(1.1)	0.1	(14.4)
Accounts payable	**(5.8)**	(16.2)	6.6	(0.6)
Accrued taxes payable	**(5.5)**	5.1	78.5	(58.6)
Accrued interest payable	**(3.3)**	1.5	6.4	(8.1)
Pension, retiree and other benefits	**1.8**	28.5	10.2	(34.2)
Unamortized investment tax credit	**(0.5)**	(0.3)	(0.2)	(2.3)
Insurance and claims costs	**(4.8)**	(2.8)	(0.1)	4.3
Other deferred debits, **DPL** stock held in trust	**-**	-	(26.9)	-
Other	**16.3**	(26.3)	(7.9)	15.5
Net cash from operating activities	**302.8**	291.5	(1.4)	334.4
Cash flows from investing activities:				
Capital expenditures	**(124.4)**	(198.1)	(30.5)	(174.2)
Proceeds from sale of property - other	**0.8**	1.1	-	-
Insurance proceeds	**7.6**	-	-	-
Purchase of renewable energy credits	**(3.9)**	(5.4)	(0.6)	(3.8)
Purchase of MC Squared	**-**	-	-	(8.3)
Decrease / (increase) in restricted cash	**(2.8)**	2.9	1.0	(4.8)
Purchases of short-term investments	**-**	-	-	(1.7)
Sales of short-term investments	**-**	-	-	70.9
Other investing activities, net	**(1.2)**	0.3	(0.3)	1.2
Net cash from investing activities	**(123.9)**	(199.2)	(30.4)	(120.7)

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

$ in millions	Successor: Year ended December 31, 2013	Successor: Year ended December 31, 2012	Successor: November 28, 2011 through December 31, 2011	Predecessor: January 1, 2011 through November 27, 2011
Cash flows from financing activities:				
Dividends paid on common stock	**-**	(64.1)	(63.0)	(113.0)
Contributions to additional paid-in capital from parent	**-**	0.3	-	-
Payment to former warrant holders	**-**	(9.0)	-	-
Deferred financing costs	**(15.3)**	(0.8)	-	-
Proceeds from exercise of warrants	**-**	-	-	14.7
Proceeds from liquidation of **DPL** stock, held in trust	**-**	-	26.9	-
Retirement of debt	**(945.1)**	(0.1)	-	(419.5)
Premium paid for early redemption of debt	**(2.4)**	-	-	(12.2)
Issuance of long-term debt	**645.0**	-	125.0	300.0
Payment of MC Squared debt	**-**	-	-	(13.5)
Borrowings from revolving credit facilities	**50.0**	-	-	50.0
Repayment of borrowings from revolving credit facilities	**(50.0)**	-	-	(50.0)
Exercise of stock options	**-**	-	-	1.6
Tax impact related to exercise of stock options	**-**	-	-	1.4
Net cash from financing activities	**(317.8)**	(73.7)	88.9	(240.5)
Cash and cash equivalents:				
Net change	**(138.9)**	18.6	57.1	(26.8)
Assumption of cash at acquisition	**-**	-	19.2	-
Balance at beginning of period	**192.1**	173.5	97.2	124.0
Cash and cash equivalents at end of period	**$ 53.2**	$ 192.1	$ 173.5	$ 97.2
Supplemental cash flow information:				
Interest paid, net of amounts capitalized	**$ 137.5**	$ 136.9	$ 6.0	$ 62.0
Income taxes (refunded) / paid, net	**$ (5.2)**	$ 47.6	$ -	$ 25.6
Non-cash financing and investing:				
Accruals for capital expenditures	**$ 14.7**	$ 16.7	$ 26.5	$ 18.9
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, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 53.2	$ 192.1
Restricted cash	13.5	10.7
Accounts receivable, net (Note 3)	203.3	208.2
Inventories (Note 3)	82.7	110.1
Taxes applicable to subsequent years	70.6	69.3
Regulatory assets, current (Note 4)	20.8	21.1
Other prepayments and current assets	35.1	43.1
Total current assets	479.2	654.6
Property, plant and equipment:		
Property, plant and equipment	2,677.0	2,590.4
Less: Accumulated depreciation and amortization	(206.7)	(115.9)
	2,470.3	2,474.5
Construction work in process	63.9	89.3
Total net property, plant and equipment	2,534.2	2,563.8
Other non-current assets:		
Regulatory assets, non-current (Note 4)	159.7	185.5
Goodwill	452.8	759.1
Intangible assets, net of amortization (Note 6)	42.8	50.1
Other deferred assets	52.8	34.2
Total other non-current assets	708.1	1,028.9
Total Assets	$ 3,721.5	$ 4,247.3

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	December 31, 2013	December 31, 2012
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 7)	$ 10.2	$ 584.9
Accounts payable	78.2	83.2
Accrued taxes	89.4	97.1
Accrued interest	28.5	31.8
Customer security deposits	13.9	15.0
Regulatory liabilities, current (Note 4)	-	0.1
Insurance and claims costs	6.7	11.5
Other current liabilities	64.2	96.9
Total current liabilities	291.1	920.5
Non-current liabilities:		
Long-term debt (Note 7)	2,284.2	2,025.0
Deferred taxes (Note 8)	564.3	534.9
Taxes payable	79.1	68.1
Regulatory liabilities, non-current (Note 4)	121.1	117.3
Pension, retiree and other benefits (Note 9)	51.6	61.6
Unamortized investment tax credit	2.8	3.3
Other deferred credits	69.4	71.4
Total non-current liabilities	3,172.5	2,881.6
Redeemable preferred stock of subsidiary	18.4	18.4
Commitments and contingencies (Note 16)		
Common shareholder's equity:		
Common stock:		
1,500 shares authorized; 1 share issued and outstanding at December 31, 2013 and 2012	2,237.0	2,236.7
Accumulated other comprehensive gain / (loss)	24.6	(3.9)
Retained earnings / (deficit)	(2,022.1)	(1,806.0)
Total common shareholder's equity	239.5	426.8
Total Liabilities and Shareholder's Equity	$ 3,721.5	$ 4,247.3

See Notes to Consolidated Financial Statements.

DPL INC.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

$ in millions (except Outstanding Shares)	Common Stock [b] Outstanding Shares	Common Stock [b] Amount	Warrants	Common Stock Held by Employee Plans	Accumulated Other Comprehensive Income / (Loss)	Other Paid-in Capital	Retained Earnings/ (Deficit)	Total
Beginning 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
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
Year ended December 31, 2013 (Successor)								
Total comprehensive income (loss)					**28.5**		**(222.0)**	**(193.5)**
Common stock dividends [a]							-	-
Other [c]						**0.3**	**5.9**	**6.2**
Ending balance	**1**	**$ -**	**$ -**	**$ -**	**$ 24.6**	**$ 2,237.0**	**$ (2,022.1)**	**$ 239.5**

(a) Common stock dividends were $70.0 million in the year ended December 31, 2012, $0.00 per share in the period November 28, 2011 through December 31, 2011 and $1.54 per share in the period January 1, 2011 through November 27, 2011.

(b) $0.01 par value, 250,000,000 shares authorized through December 31, 2011; 1,500 shares authorized from January 1, 2011 onwards.

(c) $5.9 million of dividends declared in 2012 were reversed in 2013.

See Notes to Consolidated Financial Statements.

Note 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. See Note 17 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. Beginning in 2001, Ohio law gave Ohio consumers the right to choose the electric generation supplier from whom they purchase retail generation service, however distribution and transmission retail service are still regulated. **DP&L** has exclusive right to provide such service to its more than 515,000 customers located in West Central Ohio. Additionally, **DP&L** offers retail SSO electric service to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio and generates electricity at seven coal-fired power stations. Beginning in 2014, **DP&L** no longer provides 100% of the generation for its SSO customers. Principal industries located in **DP&L's** service territory include automotive, food processing, paper, plastic, manufacturing and defense. **DP&L's** sales reflect the general economic conditions, seasonal weather patterns of the area and the market price of electricity. **DP&L** sells any excess energy and capacity into the wholesale market. **DP&L** also sells electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

DP&L filed a generation separation application at the end of December 2013, as required in its ESP order, with the PUCO and on February 25, 2013, filed a supplemental application. In the supplemental application, **DP&L** reaffirmed its commitment to separate the generation assets on or before May 31, 2017. **DP&L** continues to look at multiple options to effectuate the separation including transfer into a new unregulated affiliate of **DPL** or through a sale.

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 308,000 customers currently located throughout Ohio and Illinois. Approximately 130,000 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 1,266 people as of December 31, 2013, of which 1,218 employees were employed by **DP&L**. Approximately 59% 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.

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 fourth quarter of 2013, we recorded an impairment of $306.3 against the goodwill at **DPL's** DP&L reporting unit. 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 18 for information regarding the impairments of goodwill in 2013 and 2012.

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 to Duke Energy during the years ended December 31, 2013 and 2012 was $20.7 million and $15.7 million, respectively. In addition, MC Squared sells receivables from their customers in ComEd territory to ComEd. Total receivables sold to ComEd during the years ended December 31, 2013 and 2012 was $75.4 million and $27.7 million, respectively.

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 $1.5 million, $4.0 million, $0.5 million and $3.9 million in the years ended December 31, 2013, and 2012, the period from November 28, 2011 through December 31, 2011, and the period January 1, 2011 through November 27, 2011, respectively.

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

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

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

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.

During the fourth quarter of 2013, the Company tested the recoverability of long-lived assets at certain generating stations. See Note 19 for more information. Gradual decreases in power prices as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit of **DPL** failing step 1 of the annual goodwill impairment test were collectively determined to be an impairment indicator. The effect of this impairment will be to reduce future depreciation related to these stations by approximately $1.6 million per year.

For **DPL's** generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 5.8% in 2013, 4.8% in 2012 and 5.8% in 2011.

The following is a summary of **DPL's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2013 and 2012:

	December 31,			
$ in millions	**2013**	**Composite Rate**	2012	Composite Rate
Regulated:				
Transmission	**$ 213.1**	**4.1%**	$ 208.9	4.4%
Distribution	**970.1**	**5.6%**	935.0	5.4%
General	**56.8**	**12.1%**	50.6	10.8%
Non-depreciable	**60.8**	**N/A**	60.0	N/A
Total regulated	**1,300.8**		1,254.5	
Unregulated:				
Production / Generation	**1,340.8**	**6.2%**	1,299.7	4.4%
Other	**15.7**	**8.9%**	16.6	11.6%
Non-depreciable	**19.7**	**N/A**	19.6	N/A
Total unregulated	**1,376.2**		1,335.9	
Total property, plant and equipment in service	**$ 2,677.0**	**5.8%**	$ 2,590.4	4.8%

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 consolidated 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	
Balance at December 31, 2011	$ 23.6
Calendar 2012	
Accretion expense	0.8
Settlements	(0.4)
Estimated cash flow revisions	(0.1)
Balance at December 31, 2012	23.9
Calendar 2013	
Accretion expense	0.8
Settlements	(0.3)
Balance at December 31, 2013	$ 24.4

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 $114.9 million and $112.1 million in estimated costs of removal at December 31, 2013 and 2012, 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

$ in millions		
Balance at December 31, 2011	$	112.4
Calendar 2012		
Additions		10.1
Settlements		(10.4)
Balance at December 31, 2012		112.1
Calendar 2013		
Additions		22.0
Settlements		(19.2)
Balance at December 31, 2013	$	114.9

Regulatory Accounting
As a regulated utility, we apply the provisions of FASC 980 *"Regulated Operations,"* which gives recognition to the ratemaking and accounting practices of the PUCO and the FERC. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory assets can also represent performance incentives permitted by the regulator, such as with our CCEM energy efficiency program. Regulatory assets have been included as allowable costs for ratemaking purposes, as authorized by the PUCO or established regulatory practices. Regulatory liabilities generally represent obligations to make refunds or future rate reductions to customers for previous over collections or the deferral of revenues collected for costs that **DPL** expects to incur in the future.

The deferral of costs (as regulatory assets) is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific orders from the PUCO or FERC, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed probable, related regulatory assets would be required to be expensed in current period earnings. Our regulatory assets and liabilities have been created pursuant to a specific order of the PUCO or FERC or established regulatory practices, such as other utilities under the jurisdiction of the PUCO or FERC being granted recovery of similar costs. It is probable, but not certain, that these regulatory assets will be recoverable, subject to PUCO or FERC approval. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 4 for more information about 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.

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 was 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.

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

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

DPL 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.

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 years ended December 31, 2013, and 2012, the period November 28, 2011 through December 31, 2011, and the period January 1, 2011 through November 27, 2011, were $50.5 million, $50.5 million, $4.3 million and $49.4 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, discussed in Note 2, vesting of all share-based awards was accelerated as of the Merger date, and none are in existence at December 31, 2013 or 2012.

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.

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. **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 $18.8 million and $17.7 million at 2013 and 2012, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for workers' compensation, medical, life and disability costs at **DP&L** are actuarially determined based using certain assumptions. 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
Effective December 22, 2013, AES US Services, LLC (the "Service Company") began providing services including accounting, legal, human resources, information technology and other services of a similar nature on behalf of the AES U.S. Strategic Business Unit ("U.S. SBU"). The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable distribution. This includes ensuring that the regulatory utilities served, including **DP&L**, are not subsidizing costs incurred for the benefit of non-regulated businesses.

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 $0.4 million and $0.5 million at December 31, 2013 and 2012, 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 at December 31, 2013 and 2012 , respectively, 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>

Offsetting Assets and Liabilities
In December 2011, the FASB issued ASU 2011-11 "Disclosures about Offsetting Assets and Liabilities" (ASU 2011-11) effective for interim and annual reporting periods beginning on or after January 1, 2013. We adopted ASU 2011-11 on January 1, 2013. This standard was clarified by ASU 2013-01 "Scope Clarification of Disclosures about Offsetting Assets and Liabilities", which also was effective on January 1, 2013. This standard updates FASC Topic 210 "Balance Sheet." ASU 2011-11 updates the disclosures for financial instruments and derivatives to provide more transparent information around the offsetting of assets and liabilities. Entities are required to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and/or subject to an agreement similar to a master netting agreement. In ASU 2013-01, 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. We adopted this rule, which resulted in enhanced disclosures, but it did not have an effect on our overall results of operations, financial position or cash flows.

Testing Indefinite-Lived Intangible Assets for Impairments
In July 2012, the FASB issued ASU 2012-02 "Testing Indefinite-Lived Intangible Assets for Impairment" (ASU 2012-02) effective for interim and annual impairment tests performed for fiscal years beginning after September 15, 2012. We adopted ASU 2012-02 on January 1, 2013. This standard updates FASC Topic 350 "Intangibles-

Goodwill and Other." ASU 2012-02 permits an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired as a basis for determining whether it is necessary to perform the quantitative impairment test in accordance with FASC Subtopic 350-30. We adopted this rule but it did not have an effect on our overall results of operations, financial position or cash flows.

Comprehensive Income
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. ASU 2013-02 does not change the current requirements for reporting net income or OCI in financial statements. However, this ASU requires an entity to provide information about the amounts reclassified out of AOCI 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 AOCI by the respective line items of net income, but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. We adopted this rule, which resulted in enhanced disclosures, but it did not have an effect on our overall results of operations, financial position or cash flows.

Note 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

Note 3 – Supplemental Financial Information

$ in millions	December 31, 2013	December 31, 2012
Accounts receivable, net		
Unbilled revenue	**$ 77.8**	$ 75.2
Customer receivables	**102.7**	98.2
Amounts due from partners in jointly-owned stations	**15.8**	19.7
Coal sales	**-**	1.6
Other	**8.2**	14.6
Provisions for uncollectible accounts	**(1.2)**	(1.1)
Total accounts receivable, net	**$ 203.3**	$ 208.2
Inventories		
Fuel and limestone	**$ 42.7**	$ 67.3
Plant materials and supplies	**38.2**	41.0
Other	**1.8**	1.8
Total inventories, at average cost	**$ 82.7**	$ 110.1

Accumulated Other Comprehensive Income / (Loss)

The amounts reclassified out of Accumulated Other Comprehensive Income / (Loss) by component during the years ended December 31, 2013 and 2012 and the periods November 28, 2011 through December 31, 2011 and January 1, 2011 through November 27, 2011 are as follows:

Details about Accumulated Other Comprehensive Income / (Loss) Components	**Affected line item in the Consolidated Statements of Operations**	**Successor**			**Predecessor**
$ in millions		**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Gains and losses on Available-for-sale securities activity (Note 10):					
	Other income / (deductions)	$ **2.1**	$ (0.1)	$ -	$ -
	Total before income taxes	**2.1**	(0.1)	-	-
	Tax expense	**(0.7)**	-	-	-
	Net of income taxes	**1.4**	(0.1)	-	-
Gains and losses on cash flow hedges (Note 11):					
	Interest Expense	**-**	0.2	-	(2.3)
	Revenue	**2.2**	(0.1)	-	1.3
	Purchased power	**3.5**	(1.1)	-	1.0
	Total before income taxes	**5.7**	(1.0)	-	-
	Tax expense	**(2.3)**	0.5	-	(0.3)
	Net of income taxes	**3.4**	(0.5)	-	(0.3)
Amortization of defined benefit pension items (Note 9):					
	Reclassification to Other income / (deductions)	**-**	-	-	4.3
	Tax benefit	**0.3**	-	-	(1.5)
	Net of income taxes	**0.3**	-	-	2.8
Total reclassifications for the period, net of income taxes		$ **5.1**	$ (0.6)	$ -	$ 2.5

The changes in the components of Accumulated Other Comprehensive Income / (Loss) during the years ended December 31, 2013 and 2012 are as follows:

$ in millions	Gains / (losses) on available-for-sale securities	Gains / (losses) on cash flow hedges	Change in unfunded pension obligation	Total
Balance January 1, 2012	$ -	$ (0.5)	$ 0.1	$ (0.4)
Other comprehensive income / (loss) before reclassifications	0.5	(1.5)	(1.9)	(2.9)
Amounts reclassified from accumulated other comprehensive income / (loss)	(0.1)	(0.5)	-	(0.6)
Net current period other comprehensive income / (loss)	0.4	(2.0)	(1.9)	(3.5)
Balance December 31, 2012	0.4	(2.5)	(1.8)	(3.9)
Other comprehensive income / (loss) before reclassifications	**(1.2)**	**19.7**	**4.9**	**23.4**
Amounts reclassified from accumulated other comprehensive income / (loss)	**1.4**	**3.4**	**0.3**	**5.1**
Net current period other comprehensive income	**0.2**	**23.1**	**5.2**	**28.5**
Balance December 31, 2013	**$ 0.6**	**$ 20.6**	**$ 3.4**	**$ 24.6**

Note 4 – Regulatory Matters

In accordance with FASC 980, we have recognized total regulatory assets of $180.5 million and $206.6 million as of December 31, 2013 and 2012 and total regulatory liabilities of $121.1 million and $117.4 million as of December 31, 2013 and 2012. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 1 for accounting policies regarding Regulatory Assets and Liabilities.

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

$ in millions	Type of Recovery [(a)]	Amortization Through	December 31, 2013	2012
Regulatory assets, current:				
Transmission costs	F	2014	$ **2.6**	$ 7.0
Fuel and purchased power recovery costs	C	2014	**6.3**	14.1
Energy efficiency program	F	2014	**7.7**	-
Other miscellaneous		2014	**4.2**	-
Total regulatory assets, current			$ **20.8**	$ 21.1
Regulatory assets, non-current:				
Deferred recoverable income taxes	B/C	Ongoing	$ **32.4**	$ 35.1
Pension benefits	C	Ongoing	**77.1**	88.9
Unamortized loss on reacquired debt	C	Various	**10.9**	11.9
Deferred storm costs	D	Undetermined	**25.6**	24.4
CCEM smart grid and advanced metering infrastructure costs	D		**6.6**	6.6
Energy efficiency program costs	F	2014	**-**	5.2
Consumer education campaign	D	Undetermined	**3.0**	3.0
Retail settlement system costs	D	Undetermined	**3.1**	3.1
Other miscellaneous		Undetermined	**1.0**	7.3
Total regulatory assets, non-current			$ **159.7**	$ 185.5
Regulatory liabilities, current:				
Other miscellaneous			$ **-**	$ 0.1
Total regulatory liabilities, current			$ **-**	$ 0.1
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated property			$ **115.0**	$ 112.1
Postretirement benefits			**5.6**	5.0
Other miscellaneous			**0.5**	0.2
Total regulatory liabilities, non-current			$ **121.1**	$ 117.3

(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

Transmission 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.

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. As part of the PUCO approval process, an outside auditor reviews fuel costs and the fuel procurement process. An audit of 2012 fuel costs occurred in 2013. On June 12, 2013, and applicable for the calendar year 2012 period, we received a report from that external auditor recommending a pre-tax disallowance of $5.3 million in charges to the fuel and purchased power recovery rider in 2012; a portion of which was recorded as a reserve against the regulatory asset. A hearing in this case was held on December 9, 2013, and we expect an order in the case in the second quarter of 2014.

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. Due to the short-term nature of the remaining amortization period, the balance was reclassified to current regulatory assets in 2013 and is included in *Other miscellaneous* in the table above.

Deferred storm costs relate to costs incurred to repair the damage caused to **DP&L's** transmission and distribution equipment by major storms in 2008, 2011 and 2012. **DP&L** filed an application with the PUCO in 2012 to recover these costs. There has been disagreement among **DP&L,** the PUCO staff and other intervenors in the case as to what portion of these storm costs should be recoverable. We continue to believe the costs we have deferred are probable for recovery based on established regulatory practices in the state of Ohio. A hearing is scheduled for this matter in March 2014. The outcome of this case is uncertain at this time.

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.

Energy efficiency program costs represent costs incurred to develop and implement various 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 an annual true-up for any over/under recovery of costs.

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 costs Please see "*Regulatory Assets – Fuel and purchased power recovery costs*" above.

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.

Note 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, 2013, **DP&L** had $24.0 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 the coal portion of our wholly-owned coal fired* Hutchings Station at December 31, 2013, 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	$ 2	$ 1	$ -	No
Conesville Unit 4	16.5	129	24	-	-	Yes
East Bend Station	31.0	186	12	5	-	Yes
Killen Station	67.0	402	306	9	4	Yes
Miami Fort Units 7 and 8	36.0	368	212	13	1	Yes
Stuart Station	35.0	808	205	12	16	Yes
Zimmer Station	28.1	365	177	25	3	Yes
Transmission (at varying percentages)			41	4	-	
Total		2,465	$ 979	$ 69	$ 24	
Wholly-owned production unit						
Hutchings Station	100.0	-	$ -	$ -	$ -	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.

As part of a settlement with the USEPA regarding Hutchings Station, **DP&L** signed an Administrative Consent Order and a Consent Agreement and Final Order (CAFO) that was filed on September 26, 2013. Together, these two agreements resolved the opacity and particulate emissions NOV at the Hutchings Station and required that all six coal-fired units at Hutchings cease operating on coal by September 30, 2013, and included an immaterial penalty and the completion of a Supplemental Environmental Project of $0.2 million within one year. The units were disabled for coal operations prior to September 30, 2013. We do not believe that any additional accruals are needed related to the Hutchings Station. A related agreement in the form of Administrative Findings and Order, also involving an immaterial penalty, was executed October 4, 2013, with Ohio's Regional Air Pollution Control Agency, which resolves a separate but related NOV relating to a failed stack test in 2006. These agreements do not affect Hutchings unit 7, a small combustion turbine.

Note 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 fourth quarter of 2013, **DPL** recognized an impairment of goodwill in the amount of $306.3 million. In the third quarter of 2012, **DPL** recognized an estimated impairment of goodwill of $1,850.0 million; the valuation of the goodwill impairment was finalized and adjusted to $1,817.2 million in the fourth quarter of 2012. See Note 18 for more information about these impairments.

The following table summarizes the changes in Goodwill:

$ in millions	DP&L Reporting Unit	DPLER Reporting Unit	Total
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
Goodwill impairments during 2012	$ (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
Goodwill impairments during 2013	$ (306.3)	$ -	$ (306.3)
Balance at December 31, 2013			
Goodwill	$ 2,440.5	$ 135.8	$ 2,576.3
Accumulated impairment losses	(2,123.5)	-	(2,123.5)
Net balance at December 31, 2013	$ 317.0	$ 135.8	$ 452.8

The following tables summarize the balances comprising intangible assets as of December 31, 2013:

$ in millions	December 31, 2013			December 31, 2012		
	Gross Balance	**Accumulated Amortization**	**Net Balance**	Gross Balance	Accumulated Amortization	Net Balance
Subject to Amortization						
Electric Security Plan [(a)]	$ -	$ -	$ -	$ 87.0	$ (87.0)	$ -
Customer Contracts [(b)]	27.0	(25.8)	1.2	28.0	(19.7)	8.3
Customer Relationships [(c)]	31.8	(4.6)	27.2	31.8	(1.1)	30.7
Other [(d)]	8.4	(0.1)	8.3	5.3	(0.3)	5.0
	67.2	(30.5)	36.7	152.1	(108.1)	44.0
Not subject to Amortization						
Trademark/Trade name [(e)]	6.1	-	6.1	6.1	-	6.1
Total intangibles	$ 73.3	$ (30.5)	$ 42.8	$ 158.2	$ (108.1)	$ 50.1

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.

(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, 2013:

$ in millions	**Amount**	**Subject to Amortization/ Indefinite-lived**	**Weighted Average Amortization Period (years)**	**Amortization Method**
Renewable Energy Certificates	$ 3.9	Subject to amortization	Various	As Utilized

The following table summarizes the amortization expense, broken down by intangible asset category for 2014 through 2018:

	Estimated amortization expense				
	Years ending December 31,				
$ in millions	2014	2015	2016	2017	2018
Customer contracts	$ 1.2	$ -	$ -	$ -	$ -
Customer relationships	3.8	3.8	3.1	2.7	2.3
Renewable Energy Certificates	3.8	0.3	-	-	-
	$ 8.8	$ 4.1	$ 3.1	$ 2.7	$ 2.3

Note 7 – Debt Obligations

Long-term debt

$ in millions	December 31, 2013	December 31, 2012
First mortgage bonds due in September 2016 - 1.875%	$ 444.3	$ -
Pollution control series due in January 2028 - 4.7%	36.0	36.1
Pollution control series due in January 2034 - 4.8%	179.6	179.6
Pollution control series due in September 2036 - 4.8%	96.4	96.3
Pollution control series due in November 2040 - variable rates: 0.05% - 0.24% and 0.04% - 0.26% (a)	100.0	-
U.S. Government note due in February 2061 - 4.2%	18.3	18.3
Capital lease obligations	-	0.1
Total long-term debt at subsidiary	874.6	330.4
Bank term loan due in August 2014 (repaid in May 2013) - variable rates: 2.46% and 1.48% - 4.25% (a)	-	425.0
Bank term loan due in May 2018 - variable rates: 2.42% - 2.45% (a)	180.0	-
Senior unsecured bonds due in October 2016 - 6.50%	430.0	450.0
Senior unsecured bonds due in October 2021 - 7.25%	780.0	800.0
Note to DPL Capital Trust II due in September 2031 - 8.125%	19.6	19.6
Total long-term debt	$ 2,284.2	$ 2,025.0

(a) - range of interest rates for the twelve months ended December 31, 2013 and December 31, 2012, respectively

Current portion - long-term debt

$ in millions	December 31, 2013	December 31, 2012
First mortgage bonds due in October 2013 - 5.125%	$ -	$ 484.5
Pollution control series due in November 2040 - variable rates: 0.05% - 0.24% and 0.04% - 0.26% (a)	-	100.0
Bank term loan due in May 2018 - variable rates: 2.42% - 2.45% (a)	10.0	-
U.S. Government note due in February 2061 - 4.2%	0.1	0.1
Capital lease obligations	0.1	0.3
Total current portion - long-term debt	$ 10.2	$ 584.9

(a) - range of interest rates for the twelve months ended December 31, 2013 and December 31, 2012, respectively

The presentation above for the Successor is based on the revaluation of the debt at the Merger date. At December 31, 2013, maturities of long-term debt, including capital lease obligations, are summarized as follows:

Due within the twelve months ending December 31,

$ in millions		
2014	$	10.2
2015		40.1
2016		915.1
2017		40.1
2018		60.1
Thereafter		1,232.8
		2,298.4
Unamortized discounts and premiums, net		(4.0)
Total long-term debt	$	2,294.4

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

On December 4, 2008, the OAQDA issued $100.0 million of collateralized, variable rate Revenue Refunding Bonds Series A and B due November 1, 2040. In turn, **DP&L** borrowed these funds from the OAQDA and issued corresponding first mortgage bonds to support repayment of the funds. The payment of principal and interest on each series of the bonds when due is backed by a standby letter of credit issued by JPMorgan Chase Bank, N.A. This letter of credit facility, which expires in December 2013, is irrevocable and has no subjective acceleration clauses. **DP&L** amended these standby letters of credit on May 31, 2013 and extended the stated maturities to June 2018. These amended facilities are irrevocable, have no subjective acceleration clauses and remain subject to terms and conditions that are substantially similar to those of the pre-existing facilities. Fees associated with this letter of credit facility were not material during the years ended December 31, 2013 and 2012, the period November 28, 2011 through December 31, 2011 and the period January 1, 2011 through November 27, 2011.

On April 20, 2010, **DP&L** entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement was for a three year term expiring on April 20, 2013, was extended through May 31, 2013 pursuant to an amendment dated April 11, 2013 and provided **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 at the termination of the agreement in May 2013. Fees associated with this revolving credit facility were not material during the years ended December 31, 2013 and 2012, the period November 28, 2011 through December 31, 2011, the period January 1, 2011 through November 27, 2011. This facility also contained a $50.0 million letter of credit sublimit. **DP&L** had no outstanding letters of credit against the facility at December 31, 2012 or at the termination of the agreement in May 2013.

On August 24, 2011, **DP&L** entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement, originally for a three year term expiring on April 20, 2013, was extended through May 31, 2013 pursuant to an amendment dated April 11, 2013 and provided **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 at the termination of the agreement in May 2013. Fees associated with this revolving credit facility were not material during the years ended December 31, 2013 and 2012 or the five months ended December 31, 2011. This facility also contained a $50.0 million letter of credit sublimit. **DP&L** had no outstanding letters of credit against the facility at December 31, 2012 or at the termination of the agreement in May 2013.

On May 10, 2013, **DP&L** terminated both of the unsecured revolving credit agreements mentioned above and concurrently closed a new $300.0 million unsecured revolving credit agreement with a syndicated bank group. This new $300.0 million facility has a five year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature which provides **DP&L** the ability to increase the size of the facility by an additional $100.0 million. The other terms and conditions of this new revolving credit facility are substantially similar to those of the pre-existing **DP&L** revolving credit facilities. **DP&L** had no outstanding borrowings under this facility at December 31, 2013. At December 31, 2013, there was a letter of credit in the amount of $0.4 million outstanding, with the remaining $299.6 million available to **DP&L**. Fees associated with this revolving credit facility were not material during the twelve months ended December 31, 2013.

DP&L's prior unsecured revolving credit agreements and **DP&L's** standby letters of credit had one financial covenant which measured Total Debt to Total Capitalization. The Total Debt to Total Capitalization ratio is calculated, at the end of each fiscal quarter, by dividing total debt at the end of the quarter by total capitalization at the end of the quarter. **DP&L's** new unsecured revolving credit agreement and **DP&L's** amended standby letters of credit maintain the Total Debt to Total Capitalization financial covenant and add the EBITDA to Interest Expense ratio as a second financial covenant. The EBITDA to Interest Expense ratio is calculated, at the end of each fiscal quarter, by dividing EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period.

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 September 19, 2013, **DP&L** closed a $445.0 million issuance of senior secured first mortgage bonds. These new bonds mature on September 15, 2016, and are secured by **DP&L's** First & Refunding Mortgage. Substantially all property, plant and equipment of **DP&L** is subject to the lien of the First and Refunding Mortgage. On October 1, 2013, **DP&L** used the net proceeds of these new bonds, along with cash on hand, to redeem, at par value, the $470.0 million of first mortgage bonds that matured on October 1, 2013.

On August 24, 2011, **DPL** entered into a $125.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement was 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, 2013 or at the termination of the agreement in May 2013. Fees associated with this revolving credit facility were not material during the years ended December 31, 2013 and 2012. This facility also could have been used to issue letters of credit up to the $75.0 million limit. **DPL** had no outstanding letters of credit against the facility at December 31, 2012 or at the termination of the agreement in May 2013.

On August 24, 2011, **DPL** entered into a $425.0 million unsecured term loan agreement with a syndicated bank group. This agreement was for a three year term expiring on August 24, 2014. Concurrent with the inception of the new term loan discussed below, this term loan was terminated on May 10, 2013. **DPL** had borrowed the entire $425.0 million available under the facility at December 31, 2013. Fees associated with this term loan were not material during the years ended December 31, 2013, 2012 and 2011.

On May 10, 2013, **DPL** entered into a new $200.0 million unsecured term loan agreement. This new term loan has a five year term expiring on May 10, 2018; however, if **DPL** has not either: (a) prepaid the full $200.0 million term loan balance; or (b) refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then the maturity of this new **DPL** term loan shall be July 15, 2016. This term loan amortizes at 5% of the original balance per quarter from September 2014 to maturity. The other terms and conditions of this new revolving credit facility are substantially similar to those of the pre-existing **DPL** term loan. Fees associated with this new term loan were not material during the year ended December 31, 2013.

On May 10, 2013, **DPL** entered into a new $100.0 million unsecured revolving credit facility and concurrently terminated the existing $75.0 million facility. This new $100.0 million facility has a $100.0 million letter of credit sublimit and a feature which provides **DPL** the ability to increase the size of the facility by an additional $50.0 million. This new facility has a five year term expiring on May 10, 2018; however, if **DPL** has not refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then the maturity of this new **DPL** credit facility shall be July 15, 2016. The other terms and conditions of this new revolving credit facility are substantially similar to those of the pre-existing **DPL** revolving credit facility. **DPL** had no outstanding letters of credit under this credit facility at December 31, 2013. Fees associated with this revolving credit facility were not material during the year ended December 31, 2013.

Concurrent with the inception of the new revolving credit facility and term loan, **DPL** terminated the $425.0 million term loan agreement, and used $175.0 million of cash on hand, $50.0 million from the new **DPL** credit facility and $200.0 million from a one-time draw on the new term loan, to prepay the outstanding $425.0 million term loan balance. The $50.0 million draw on the **DPL** revolving credit facility was repaid on July 10, 2013 and **DPL** prepaid $10 million of the outstanding balance on this new term loan in December 2013 reducing the outstanding balance as of December 31, 2013 to $190.0 million.

DPL's prior unsecured revolving credit agreement and unsecured term loan had and **DPL's** new unsecured revolving credit agreement and unsecured term loan have, two financial covenants. The first financial covenant, a Total Debt to EBITDA ratio, is calculated at the end of each fiscal quarter by dividing total debt at the end of the current quarter by consolidated EBITDA for the four prior fiscal quarters. The second financial covenant is an EBITDA to Interest Expense ratio that is calculated, at the end of each fiscal quarter, by dividing EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period.

DPL's prior and new (executed on May 10, 2013), unsecured revolving credit agreement and unsecured term loan restrict dividend payments from **DPL** to AES and adjust the cost of borrowing under the facilities under certain credit rating scenarios.

In connection with the closing of the Merger, discussed in Note 2, **DPL** assumed $1,250.0 million of debt that Dolphin Subsidiary II, Inc., a subsidiary of AES, issued on October 3, 2011 to partially finance the Merger. The $1,250.0 million was issued in two tranches. The first tranche was $450.0 million of five year senior unsecured notes issued with a 6.50% coupon maturing on October 15, 2016. The second tranche was $800.0 million of ten year senior unsecured notes issued with a 7.25% coupon maturing on October 15, 2021. In December 2013, **DPL** executed an Open Market Repurchase Program and successfully bought back $20 million of the first tranche of five year senior unsecured notes issued with a 6.50% coupon and $20 million of the second tranche of ten year senior unsecured notes issued with a 7.25% coupon. **DPL** paid a $1.9 million and a $0.5 million premium, respectively, to repurchase these bonds. Subsequent to repurchasing these bonds **DPL** immediately retired them.

Note 8 – Income Taxes

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

	Successor			Predecessor
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Computation of tax expense				
Federal income tax expense / (benefit)[a]	$ **(69.9)**	$ (588.7)	$ (2.0)	$ 88.4
Increases (decreases) in tax resulting from:				
State income taxes, net of federal effect	**1.7**	3.5	0.1	3.8
Depreciation of AFUDC - Equity	**(3.2)**	(2.4)	(0.3)	(2.9)
Investment tax credit amortized	**(0.5)**	(0.3)	(0.2)	(2.3)
Section 199 - domestic production deduction	**(4.1)**	(2.1)	-	(3.6)
Non-deductible merger costs	**-**	-	0.1	6.0
Non-deductible merger-related compensation	**-**	0.6	3.5	-
Non-deductible goodwill impairment	**107.2**	636.0	-	-
Accrual (settlement) for open tax years	**(8.8)**	(0.1)	0.1	0.1
Compensation and benefits	**-**	-	-	13.8
Income not subject to tax	**-**	-	(0.6)	-
Other, net[b]	**(0.1)**	1.2	(0.1)	(1.3)
Total tax expense	$ **22.3**	$ 47.7	$ 0.6	$ 102.0
Components of tax expense				
Federal - current	$ **1.8**	$ 48.6	$ 0.4	$ 53.2
State and Local - current	**0.7**	1.2	0.4	0.9
Total current	**2.5**	49.8	0.8	54.1
Federal - deferred	**18.1**	(4.9)	(0.2)	43.2
State and local - deferred	**1.7**	2.8	-	4.7
Total deferred	**19.8**	(2.1)	(0.2)	47.9
Total tax expense	$ **22.3**	$ 47.7	$ 0.6	$ 102.0

Components of Deferred Tax Assets and Liabilities (Successor)

$ in millions	Years ended December 31, 2013	2012
Net non-current Assets / (Liabilities)		
Depreciation / property basis	$ **(531.5)**	$ (517.0)
Income taxes recoverable	**(11.4)**	(12.3)
Regulatory assets	**(15.6)**	(20.6)
Investment tax credit	**1.0**	1.2
Intangibles	**(3.9)**	(2.4)
Compensation and employee benefits	**(2.0)**	2.2
Long-term debt	**(1.7)**	(2.0)
Other [(c)]	**0.8**	16.0
Net non-current liabilities	$ **(564.3)**	$ (534.9)
Net current Assets / (Liabilities) [(d)]		
Other	$ **(2.6)**	$ 4.7
Net current assets / (liabilities)	$ **(2.6)**	$ 4.7

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

(b) Includes expense of $0.0 million, $1.2 million and benefits of $0.0 million and $2.3 million in the years ended December 31, 2013 and 2012, the period November 28, 2011 through December 31, 2011 and the period January 1, 2011 through November 27, 2011, respectively, of income tax related to adjustments from prior years.

(c) The Other non-current liabilities caption includes deferred tax assets of $20.7 million in 2013 and $20.4 million in 2012 related to state and local tax net operating loss carryforwards, net of related valuation allowances of $16.6 million in 2013 and $16.2 million in 2012. These net operating loss carryforwards expire from 2014 to 2027.

(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, postemployment benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

	Successor			Predecessor
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Tax expense / (benefit)	$ **15.4**	$ (2.5)	$ (1.2)	$ (33.2)

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		
Balance at January 1, 2011	$	19.4
January 1, 2011 through November 27, 2011 (Predecessor)		
Tax positions taken during prior period		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
Calendar 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
Calendar 2013 (Successor)		
Tax positions taken during prior period		(0.1)
Lapse of Statute of Limitations		(6.9)
Settlement with taxing authorities		(2.5)
Balance at December 31, 2013	$	8.8

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months other than those subject to expiring statutes of limitations.

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, 2013**	December 31, 2012
Liability	$ **0.2**	$ 0.8

Amounts in Statement of Operations	**Successor**			**Predecessor**
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Expense / (benefit)	$ **(0.6)**	$ (0.1)	$ -	$ 0.6

Following is a summary of the tax years open to examination by major tax jurisdiction:
U.S. Federal – 2010 and forward
State and Local – 2010 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months other than those subject to expiring statutes of limitations.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The results of the examination were approved by the Joint Committee on Taxation on January

18, 2013. As a result of the examination, **DPL** received a refund of $19.9 million and recorded a $1.2 million reduction to income tax expense.

Note 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. Effective December 22, 2013, certain employees of **DP&L** became employees of the Service Company of the US SBU. Employees that transferred from **DP&L** to the Service Company maintain their previous eligibility to participate in the **DP&L** pension plan.

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 provided a supplemental retirement benefit to participants by crediting an account established for each participant in accordance with the Plan requirements. We designated 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 could change his or her hypothetical investment fund selection at specified times. If a participant did not elect a hypothetical investment fund(s), then we selected 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 2012 and 2011 contributions were calculated and paid in March 2013 and 2012, respectively. The SEDCRP was terminated by the Board of Directors as of December 31, 2012. We also have an immaterial unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives.

We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. There were no contributions during the years ended December 31, 2013 and 2012 during the period November 28, 2011 through December 31, 2011. **DP&L** made a discretionary contribution of $40.0 million to the defined benefit plan during the period January 1, 2011 through November 27, 2011.

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. 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 the changes in our pension and postemployment benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2013 and 2012. 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 postemployment include both health and life insurance benefits.

$ in millions	Pension	
	Year ended December 31, 2013	Year ended December 31, 2012
Change in benefit obligation		
Benefit obligation at beginning of period	$ 395.6	$ 365.2
Service cost	7.2	6.2
Interest cost	15.6	17.3
Plan amendments	-	-
Actuarial (gain) / loss	(26.5)	29.1
Benefits paid	(21.4)	(22.2)
Benefit obligation at end of period	370.5	395.6
Change in plan assets		
Fair value of plan assets at beginning of period	361.4	335.9
Actual return on plan assets	8.7	46.2
Contributions to plan assets	0.4	1.5
Benefits paid	(21.4)	(22.2)
Fair value of plan assets at end of period	349.1	361.4
Funded status of plan	$ (21.4)	$ (34.2)

$ in millions	Postretirement	
	Year ended December 31, 2013	Year ended December 31, 2012
Change in benefit obligation		
Benefit obligation at beginning of period	$ 22.4	$ 21.7
Service cost	0.2	0.1
Interest cost	0.8	0.9
Actuarial (gain) / loss	(2.2)	1.2
Benefits paid	(1.5)	(1.7)
Medicare Part D reimbursement	-	0.2
Benefit obligation at end of period	19.7	22.4
Change in plan assets		
Fair value of plan assets at beginning of period	4.2	4.5
Actual return on plan assets	-	0.2
Contributions to plan assets	1.0	1.2
Benefits paid	(1.5)	(1.7)
Fair value of plan assets at end of period	3.7	4.2
Funded status of plan	$ (16.0)	$ (18.2)

$ in millions	Pension		Postretirement	
	December 31,		December 31,	
	2013	2012	**2013**	2012
Amounts recognized in the Balance sheets				
Current liabilities	**$ (0.4)**	$ (0.4)	**$ (0.5)**	$ (0.6)
Non-current liabilities	**(21.0)**	(33.8)	**(15.5)**	(17.6)
Net liability at Year ended December 31,	**$ (21.4)**	$ (34.2)	**$ (16.0)**	$ (18.2)

Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost	**$ 8.8**	$ 10.3	**$ 0.5**	$ 0.5
Net actuarial loss / (gain)	**63.0**	79.9	**(6.0)**	(4.5)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 71.8**	$ 90.2	**$ (5.5)**	$ (4.0)
Recorded as:				
Regulatory asset	**$ 76.3**	$ 88.0	**$ -**	$ 0.5
Regulatory liability	**-**	-	**(5.2)**	(5.0)
Accumulated other comprehensive income	**(4.5)**	2.2	**(0.3)**	0.5
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 71.8**	$ 90.2	**$ (5.5)**	$ (4.0)

The accumulated benefit obligation for our defined benefit pension plans was $359.8 million and $382.5 million at December 31, 2013 and 2012, respectively.

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

Net Periodic Benefit Cost - Pension	Successor			Predecessor
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Service cost	**$ 7.2**	$ 6.2	$ 0.5	$ 4.5
Interest cost	**15.6**	17.3	1.5	15.5
Expected return on assets [(a)]	**(23.3)**	(22.7)	(2.0)	(22.5)
Amortization of unrecognized:				
Actuarial gain	**4.9**	5.0	0.4	7.6
Prior service cost	**1.5**	1.5	0.1	2.0
Net periodic benefit cost before adjustments	**$ 5.9**	$ 7.3	$ 0.5	$ 7.1

Net Periodic Benefit Cost / (Income) - Postretirement	Successor			Predecessor
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Service cost	**$ 0.2**	$ 0.1	$ -	$ 0.1
Interest cost	**0.8**	0.9	0.1	0.9
Expected return on assets [(a)]	**(0.1)**	(0.3)	-	(0.3)
Amortization of unrecognized:				
Actuarial loss	**(0.5)**	(0.6)	-	(1.0)
Prior service cost	**-**	-	(0.1)	0.1
Net periodic benefit cost / (income) before	**$ 0.4**	$ 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 $359.8 million in 2013, $346.0 million in 2012, and $335.0 million in 2011.

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 December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Net actuarial loss / (gain)	**$ (12.0)**	$ 5.5	$ -	$ (38.7)
Prior service credit	**-**	-	-	(2.2)
Reversal of amortization item:				
Net actuarial loss	**(4.9)**	(5.0)	(0.4)	(7.6)
Prior service cost	**(1.5)**	(1.5)	(0.1)	(2.0)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (18.4)**	$ (1.0)	$ (0.5)	$ (50.5)
Total recognized in net periodic benefit cost, Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (12.5)**	$ 6.3	$ (0.5)	$ (43.4)

Other Changes in Plan Assets and Benefit Obligation Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities *(cont.)*

Postretirement	**Successor**			**Predecessor**
$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Net actuarial loss / (gain)	$ (2.0)	$ 1.0	$ -	$ 0.2
Prior service cost / (credit)	-	-	0.1	(0.1)
Reversal of amortization item:				
Net actuarial gain	0.5	0.7	-	1.0
Prior service cost	-	-	-	(0.1)
Transition asset	-	-	(0.1)	-
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ (1.5)	$ 1.7	$ -	$ 1.0
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ (1.1)	$ 1.8	$ -	$ 0.8

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2014 are:

$ in millions	Pension	Postretirement
Net actuarial gain / (loss)	$ 3.4	$ (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 2014, we have decreased our expected long-term rate of return assumption from 7.00% to 6.75% for pension plan assets and we have maintained our expected long-term rate of return on assets assumption of 6.00% for postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our current portfolio mixes. Also, for 2014, we have increased our assumed discount rate to 4.86% from 4.04% for pension and to 4.58% from 3.75% for postemployment 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 2014 pension expense of approximately $3.4 million. A 25 basis point change in the discount rate for pension would result in an increase or decrease of approximately $0.3 million to 2014 pension expense.

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 at December 31, 2013, 2012 and 2011 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2013	2012	2011	**2013**	2012	2011
Discount rate for obligations	**4.86%**	4.04%	4.88%	**4.58%**	3.75%	4.62%
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, 2013, 2012 and 2011 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2013	2012	2011	**2013**	2012	2011
Discount rate - Successor	**4.04%**	4.88%	5.31%	**4.58%**	4.62%	4.96%
Discount rate - Predecessor			4.88%			4.62%
Expected rate of return on plan assets - Successor	**6.75%**	7.00%	8.00%	**6.00%**	6.00%	6.00%
Expected rate of return on plan assets - Predecessor			7.00%			6.00%
Rate of compensation increases	**3.94%**	3.94%	3.94%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2013, 2012 and 2011 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2013	2012	2011	**2013**	2012	2011
Pre - age 65						
Current health care cost trend rate	**8.00%**	8.50%	8.50%	**7.75%**	8.00%	8.50%
Year trend reaches ultimate - Successor	**2019**	2019	2018	**2023**	2019	2019
Year trend reaches ultimate - Predecessor			2019			2019
Post - age 65						
Current health care cost trend rate	**7.50%**	8.00%	8.00%	**6.75%**	7.50%	8.00%
Year trend reaches ultimate - Successor	**2018**	2018	2017	**2021**	2018	2018
Year trend reaches ultimate - Predecessor			2018			2018
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 postemployment benefit cost and the accumulated postemployment 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	$ 0.9	$ (0.8)

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

Estimated future benefit payments and Medicare Part D reimbursements

$ in millions due within the following years:	Pension	Postretirement
2014	$ 25.0	$ 2.2
2015	$ 23.9	$ 2.1
2016	$ 23.9	$ 2.0
2017	$ 24.3	$ 1.8
2018	$ 24.6	$ 1.6
2019 - 2023	$ 126.5	$ 6.4

We expect to make contributions of $0.4 million to our SERP in 2014 to cover benefit payments. We also expect to contribute $1.9 million to our other postemployment benefit plans in 2014 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 2013 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 113.96% and is estimated to be 113.96% until the 2014 status is certified in September 2014 for the 2014 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 hedge funds that follow several different strategies.

The fair values of our pension plan assets at December 31, 2013 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2013

Asset Category $ in millions	**Market Value at December 31, 2013**	**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	$ 10.5	$ 10.5	$ -	$ -
Large cap equity	20.8	20.8	-	-
International equity	20.3	20.3	-	-
Emerging markets equity	3.2	3.2	-	-
SIIT dynamic equity	10.5	10.5	-	-
Total equity securities	65.3	65.3	-	-
Debt securities [(b)]				
Emerging markets debt	6.6	6.6	-	-
High yield bond	6.9	6.9	-	-
Long duration fund	223.3	223.3	-	-
Total debt securities	236.8	236.8	-	-
Cash and cash equivalents [(c)]				
Cash	0.9	0.9	-	-
Other investments [(d)]				
Core property collective fund	23.5	-	23.5	-
Common collective fund	22.6	-	22.6	-
Total other investments	46.1	-	46.1	-
Total pension plan assets	$ 349.1	$ 303.0	$ 46.1	$ -

(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. The fair value of cash equals its book value.

(d) This category represents a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. 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, 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	$ 324.4	$ 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 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 hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. 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 other postemployment benefit plan assets at December 31, 2013 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2013

Asset Category $ in millions	**Market Value at December 31, 2013**	**Quoted prices in active markets for identical assets** (Level 1)	**Significant observable inputs** (Level 2)	**Significant unobservable inputs** (Level 3)
JP Morgan Core Bond Fund [a]	**$ 3.7**	**$ 3.7**	**$ -**	**$ -**

(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 postemployment 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 (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (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.

This disclosure reflects changes in the 2012 presentation for $4.2 million of debt mutual funds that were previously presented as Level 2 fair value measurements which have been reclassified as Level 1 fair value measurements. This change in presentation does not impact the fair value of the securities or the financial statements for the year ended December 31, 2012.

Note 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, 2013 and 2012. See Note 11 for the fair values of our derivative instruments.

	December 31, 2013		December 31, 2012	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
Assets				
Money market funds	**$ 0.3**	**$ 0.3**	$ 0.2	$ 0.2
Equity securities	**3.3**	**4.4**	4.0	5.1
Debt securities	**5.4**	**5.5**	4.6	5.0
Hedge Funds	**0.9**	**0.9**	-	-
Real Estate	**0.4**	**0.4**	0.3	0.3
Total assets	**$ 10.3**	**$ 11.5**	$ 9.1	$ 10.6
Liabilities				
Debt	**$ 2,294.4**	**$ 2,334.6**	$ 2,609.9	$ 2,707.1

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, 2013 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 2016 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 $0.9 million ($0.6 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2013 and $0.7 million ($0.5 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2012.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. During the past twelve months, $2.1 million ($1.4 million after tax) of unrealized gains were reversed into earnings. Over the next twelve months, $0.1 million ($0.1 million after tax) of unrealized gains are expected to be reversed to earnings.

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, 2013 and 2012. These assets are part of the Master Trust. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of December 31, 2013, **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, 2013	Unfunded Commitments	Redemption Frequency
Money market fund (a)	$ 0.3	$ -	Immediate
Equity securities (b)	4.4	-	Immediate
Debt Securities (c)	5.5	-	Immediate
Hedge Funds (d)	0.9	-	Quarterly
Real Estate (e)	0.4	-	Quarterly
Total	$ 11.5	$ -	

(a) This category includes investments in high-quality, short-term securities. Investments in this category can be redeemed immediately at the current NAV.
(b) This category includes investments in hedge funds representing an S&P 500 Index and the Morgan Stanley Capital International U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current NAV 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 NAV per unit.
(d) This category includes hedge funds investing in fixed income securities and currencies, short and long-term equity investments, and a diversified fund with investments in bonds, stocks, real estate and commodities.
(e) This category includes EFT real estate funds that invest in U.S. and International properties.

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	Fair Value at December 31, 2012	Unfunded Commitments	Redemption 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	$ -	

(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);
- 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, 2013 and 2012.

The fair value of assets and liabilities at December 31, 2013 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

		Level 1	**Level 2**	**Level 3**
$ in millions	**Fair Value at December 31, 2013 (a)**	**Based on Quoted Prices in Active Markets**	**Other observable inputs**	**Unobservable inputs**
Assets				
Master trust assets				
Money market funds	$ 0.3	$ 0.3	$ -	$ -
Equity securities	4.4	-	4.4	-
Debt securities	5.5	-	5.5	-
Hedge Funds	0.9	-	0.9	-
Real Estate	0.4	-	0.4	-
Total Master trust assets	11.5	0.3	11.2	-
Derivative assets				
FTRs	0.2	-	-	0.2
Heating oil futures	0.2	0.2	-	-
Forward power contracts	13.4	-	13.4	-
Total derivative assets	13.8	0.2	13.4	0.2
Total assets	$ 25.3	$ 0.5	$ 24.6	$ 0.2
Liabilities				
Derivative liabilities				
Forward power contracts	10.6	-	10.6	-
Total derivative liabilities	10.6	-	10.6	-
Long Term Debt	2,334.6	-	2,316.1	18.5
Total liabilities	$ 2,345.2	$ -	$ 2,326.7	$ 18.5

(a) Includes credit valuation adjustment.

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

		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	Unobservable 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.

Our financial instruments are valued using the market approach in the following categories:

- 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.
- Level 3 inputs such as financial transmission rights are considered a Level 3 input 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 95% 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. An 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 no additions to our AROs during the year ended December 31, 2013.

When evaluating impairment of goodwill and long-lived assets, we measure fair value using the applicable fair value measurement guidance. Impairment expense is measured by comparing the fair value at the evaluation date to the carrying amount. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy:

$ in millions	**Year ended December 31, 2013**				
	Carrying Amount	**Fair Value Level 1**	**Fair Value Level 2**	**Fair Value Level 3**	**Gross Loss**
Assets					
Long-lived assets held and used [(a)]					
DP&L (Conesville)	**$ 26.2**	**$ -**	**$ -**	**$ -**	**$ 26.2**
Goodwill [(b)]					
DP&L Reporting unit	**$ 623.3**	**$ -**	**$ -**	**$ 317.0**	**$ 306.3**

$ in millions	Year ended December 31, 2012				
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Gross Loss
Assets					
Goodwill [(b)]					
DP&L Reporting unit	$ 2,440.5	$ -	$ -	$ 623.3	$ 1,817.2

(a) See Note 19 for further information
(b) See Note 18 for further information

The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived assets during the year ended December 31, 2013:

$ in millions	Fair Value	Valuation Technique	Unobservable input	Range (Weighted Average)
Long-lived assets held and used:				
DP&L (Conesville)	$ -	Discounted cash flows	Annual revenue growth	-31% to 18% (0%)

Cash Equivalents
DPL had $0.0 million and $130.0 million in money market funds classified as cash and cash equivalents in its Consolidated Balance Sheets at December 31, 2013 and 2012, respectively. The money market funds have quoted prices that are generally equivalent to par.

Note 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, 2013, **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	-	7.1
Heating Oil Futures	Mark to Market	Gallons	1,428.0	-	1,428.0
Forward Power Contracts	Cash Flow Hedge	MWh	140.4	(4,705.7)	(4,565.3)
Forward Power Contracts	Mark to Market	MWh	3,177.8	(2,883.1)	294.7

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

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 entered into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. These interest rate derivative contracts were settled in the third quarter of 2013. We do not hedge all interest rate exposure. We reclassify gains and losses on interest rate derivative hedges out of AOCI and 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, 2013		Year ended December 31, 2012		November 28, 2011 through December 31, 2011		January 1, 2011 through November 27, 2011	
$ in millions (net of tax)	**Power**	**Interest Rate Hedges**	Power	Interest Rate Hedges	Power	Interest Rate Hedges	Power	Interest Rate Hedges
Beginning accumulated derivative gain / (loss) in AOCI [(a)]	$ (3.0)	$ 0.5	$ 0.3	$ (0.8)	$ -	$ -	$ (1.8)	$ 21.4
Net gains / (losses) associated with current period hedging transactions	1.0	18.7	(2.6)	1.1	0.1	(0.6)	(1.2)	(57.0)
Net gains reclassified to								
Interest Expense	-	-	-	0.2	-	(0.2)	-	(2.3)
Revenues	2.1	-	(0.7)	-	0.1	-	1.1	-
Purchased Power	1.3	-	-	-	0.1	-	0.9	-
Ending accumulated derivative gain / (loss) in AOCI	$ 1.4	$ 19.2	$ (3.0)	$ 0.5	$ 0.3	$ (0.8)	$ (1.0)	$ (37.9)
Net gains / (losses) associated with the ineffective portion of the hedging transaction								
Interest Expense	$ -	$ 0.8	$ -	$ 0.2	$ -	$ 0.4	$ -	$ 5.1
Portion expected to be reclassified to earnings in the next twelve months [(b)]	$ (2.5)	$ (1.0)						
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	36	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.

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 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 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 years ended December 31, 2013 and 2012, the period November 28, 2011 through December 31, 2011, and the period January 1, 2011 through November 27, 2011.

	Successor				
	Year ended December 31, 2013				
$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain	$ -	$ -	$ 0.3	$ 0.6	$ 0.9
Realized gain	-	0.1	1.2	1.1	2.4
Total	$ -	$ 0.1	$ 1.5	$ 1.7	$ 3.3
Recorded on Balance Sheet:					
Partners' share of loss	$ -	$ -	$ -	$ -	$ -
Regulatory asset	-	-	-	-	-
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	-	-
Purchased Power	-	-	1.5	1.7	3.2
Fuel	-	0.1	-	-	0.1
O&M	-	-	-	-	-
Total	$ -	$ 0.1	$ 1.5	$ 1.7	$ 3.3

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)

The following tables show the fair value and balance sheet classification of **DPL's** derivative instruments at December 31, 2013 and 2012.

Fair Values of Derivative Instruments
December 31, 2013

$ in millions	Hedging Designation	Gross Fair Value as presented in the Consolidated Balance Sheets (a)	Gross Amounts Not Offset in the Consolidated Balance Sheets: Financial Instruments with Same Counterparty in Offsetting Position	Gross Amounts Not Offset in the Consolidated Balance Sheets: Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Cash Flow	$ 0.5	$ (0.2)	$ -	$ 0.3
Forward power contracts	MTM	4.9	(4.2)	-	0.7
FTRs	MTM	0.2	-	-	0.2
Heating oil futures	MTM	0.2	-	(0.2)	-
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Cash Flow	3.0	-	(3.0)	-
Forward power contracts	MTM	5.0	(0.3)	-	4.7
Total assets		$ 13.8	$ (4.7)	$ (3.2)	$ 5.9
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Cash Flow	$ 2.7	$ (0.2)	$ (2.3)	$ 0.2
Forward power contracts	MTM	6.6	(4.2)	(2.3)	0.1
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	MTM	1.3	(0.3)	(1.0)	-
Total liabilities		$ 10.6	$ (4.7)	$ (5.6)	$ 0.3

(a) Includes credit valuation adjustment.

As of December 31, 2013, the above table includes Forward power contracts in a short-term asset position of $5.4 million and a long-term asset position of $8.0 million. This table does not include a short-term asset position of $0.9 million or a long-term asset position of $0.1 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.

Fair Values of Derivative Instruments
December 31, 2012

$ in millions	Hedging Designation	Gross Fair Value as presented in the Consolidated Balance Sheets (a)	Gross Amounts Not Offset in the Consolidated Balance Sheets: Financial Instruments with Same Counterparty in Offsetting Position	Gross Amounts Not Offset in the Consolidated Balance Sheets: Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Cash Flow	$ 0.5	$ (0.5)	$ -	$ -
Forward power contracts	MTM	2.7	(1.5)	-	1.2
Heating oil futures	MTM	0.2	-	(0.2)	-
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Cash Flow	0.5	(0.5)	-	-
Forward power contracts	MTM	3.6	(0.6)	-	3.0
Total assets		$ 7.5	$ (3.1)	$ (0.2)	$ 4.2
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Cash Flow	$ 6.7	$ (0.5)	$ (2.1)	$ 4.1
Interest rate hedge	Cash Flow	29.5	-	-	29.5
FTRs	MTM	0.1	-	-	0.1
Forward power contracts	MTM	4.1	(1.5)	(2.0)	0.6
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Cash Flow	1.5	(0.5)	(0.9)	0.1
Forward power contracts	MTM	0.8	(0.6)	(0.1)	0.1
Total liabilities		$ 42.7	$ (3.1)	$ (5.1)	$ 34.5

(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.

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, we are 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. 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, 2013 is $10.6 million. This amount is offset by $5.6 million of collateral posted directly with third parties and in a broker margin account which offsets our loss positions on the forward contracts. This liability position is further offset by the asset position of counterparties with master netting agreements of $4.7 million. Since our debt is below investment grade, we could have to post collateral for the remaining $0.3 million.

Note 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, discussed in 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
Performance shares	$ 2.4
Restricted shares	5.3
Non-employee directors' RSUs	0.6
Management performance shares	1.8
Share-based compensation included in Operation and maintenance expense	10.1
Income tax benefit	(3.5)
Total share-based compensation, net of tax	$ 6.6

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
		January 1, 2011 through November 27, 2011
Options:		
Outstanding at beginning of period		351,500
Granted		-
Exercised		(75,500)
Expired		(276,000)
Forfeited		-
Outstanding at end of period		-
Exercisable at end of period		-
Weighted average option prices per share:		
Outstanding at beginning of period	$	28.04
Granted	$	-
Exercised	$	21.02
Expired	$	29.42
Forfeited	$	-
Outstanding at end of period	$	-
Exercisable at end of period	$	-

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
Weighted-average grant date fair value of options granted during the period	$	-
Intrinsic value of options exercised during the period	$	0.7
Proceeds from options exercised during the period	$	1.6
Excess tax benefit from proceeds of options exercised	$	0.2
Fair value of options that vested during the period	$	-
Unrecognized compensation expense	$	-
Weighted average period to recognize compensation expense (in years)		-

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
	January 1, 2011 through November 27, 2011
Performance shares:	
Outstanding at beginning of period	278,334
Granted	85,093
Dividends	(198,699)
Exercised	(66,836)
Forfeited	(97,892)
Outstanding at end of period	-
Exercisable at end of period	-

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
Weighted-average grant date fair value of performance shares granted during the period	$	2.2
Intrinsic value of performance shares exercised during the period	$	6.0
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
Unrecognized compensation expense	$	-
Weighted average period to recognize compensation expense (in years)		-

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
Expected volatility	24.0%
Weighted-average expected volatility	24.0%
Expected life (years)	3.0
Expected dividends	5.0%
Weighted-average expected dividends	5.0%
Risk-free interest rate	1.2%

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
	January 1, 2011 through November 27, 2011
Restricted shares:	
Outstanding at beginning of period	219,391
Granted	67,346
Exercised	(286,737)
Forfeited	-
Outstanding at end of period	-
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):

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

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):

	Predecessor January 1, 2011 through November 27, 2011
Restricted stock units:	
Outstanding at beginning of period	16,320
Granted	14,392
Dividends accrued	3,307
Vested and exercised	(34,019)
Vested, exercised and deferred	-
Forfeited	-
Outstanding at end of period	-
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):

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

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
	January 1, 2011 through November 27, 2011
Management performance shares:	
Outstanding at beginning of period	104,124
Granted	49,510
Expired	(31,081)
Exercised	(111,289)
Forfeited	(11,264)
Outstanding at end of period	-
Exercisable at end of period	-

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
Expected volatility	24.0%
Weighted-average expected volatility	24.0%
Expected life (years)	3.0
Expected dividends	5.0%
Weighted-average expected dividends	5.0%
Risk-free interest rate	1.2%

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, 2011	
Weighted-average grant date fair value of management performance shares granted during the period	$	1.3
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
Unrecognized compensation expense	$	-
Weighted-average period to recognize compensation expense (in years)		-

Note 13 – Redeemable Preferred Stock

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding as of December 31, 2013. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2013. The table below details the preferred shares outstanding at December 31, 2013:

		December 31, 2013 and 2012		Carrying Value [a] ($ in millions)	
	Preferred Stock Rate	Redemption price ($ per share)	Shares Outstanding	December 31, 2013	December 31, 2012
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	65,830	5.4	5.4
Total			228,508	$ 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 Concolidated 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, 2013, **DP&L's** retained earnings of $426.8 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.

Note 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, 2013.

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. See Note 2 for further discussion.

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. See Note 2 for further discussion. 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), and $4.8 million from January 1, 2011 through November 27, 2011 (predecessor).

Note 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. Effective at the Merger date, **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		
$ and shares in millions except per share amounts	Income	Shares	Per Share
Basic EPS	$ 150.5	114.5	$1.31
Effect of Dilutive Securities:			
Warrants		0.4	
Stock options, performance and restricted shares		0.2	
Diluted EPS	$ 150.5	115.1	$1.31

Note16 – 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, 2013, **DPL** had $25.9 million of guarantees to third parties for future financial or performance assurance under such agreements, including $25.6 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 $0.2 million and $0.0 million at December 31, 2013 and 2012, 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 has 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, 2013, **DP&L** could be responsible for the repayment of 4.9%, or $76.4 million, of a $1,558.4 million debt obligation comprised of both fixed and variable rate securities with maturities between 2014 and 2040. This would only happen if this electric generation company defaulted on its debt payments. At December 31, 2013, 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, 2013, 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	$ 2,298.4	$ 10.2	$ 955.2	$ 100.2	$ 1,232.8
Interest payments	944.0	114.9	229.5	151.5	448.1
Pension and postretirement payments	264.2	27.2	51.9	52.3	132.8
Operating leases	0.6	0.4	0.2	-	-
Coal contracts [(a)]	625.6	216.5	270.3	138.8	-
Limestone contracts [(a)]	24.4	6.1	12.2	6.1	-
Purchase orders and other contractual obligations	85.6	48.8	18.7	18.1	-
Total contractual obligations	$ 4,242.8	$ 424.1	$ 1,538.0	$ 467.0	$ 1,813.7

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

Long-term debt:

DPL's long-term debt as of December 31, 2013, 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.

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, 2013.

Pension and postemployment payments:

As of December 31, 2013, **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 2023.

Capital leases:

As of December 31, 2013, **DPL**, through its principal subsidiary **DP&L**, has one immaterial capital lease that expires in 2014.

Operating leases:

As of December 31, 2013, **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, 2013, **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:
Due to the uncertainty regarding the timing of future cash outflows associated with our unrecognized tax benefits of $8.8 million at December 31, 2013, we are unable to make a reliable estimate of the periods of cash settlement with the respective tax authorities and have not included such amounts in the contractual obligations table above.

Contingencies
In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our Consolidated Financial Statements, as prescribed by GAAP, are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims, tax examinations, and other matters, including the matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our Consolidated Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2013, cannot be reasonably determined.

Environmental Matters
DPL's and **DP&L's** facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. The environmental issues that may affect us include:

- The federal CAA and state laws and regulations (including State Implementation Plans) which require compliance, obtaining permits and reporting as to air emissions,
- Litigation with federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating stations require additional permitting or pollution control technology, or whether emissions from coal-fired generating stations cause or contribute to global climate changes,
- Rules and future rules issued by the USEPA and the Ohio EPA that require substantial reductions in SO_2, particulates, mercury, acid gases, NO_x, and other air emissions. **DP&L** has installed emission control technology and is taking other measures to comply with required and anticipated reductions,
- Rules and future rules issued by the USEPA and the Ohio EPA that require reporting and may require reductions of GHGs,
- Rules and future rules issued by the USEPA associated with the federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and
- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain waste. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion by-products. The USEPA has previously determined that fly ash and other coal combustion by-products are not hazardous waste subject to the Resource Conservation and Recovery Act (RCRA), but the USEPA is reconsidering that determination and planning to propose a new rule regulating coal combustion by-products. A change in determination or other additional regulation of fly ash or other coal combustion byproducts could significantly increase the costs of disposing of such by-products.

In addition to 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 our facilities to comply, or to determine compliance, with such regulations. We record liabilities for loss contingencies related to environmental matters when a loss is probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. Accordingly, we have accruals for loss contingencies of approximately $1.1 million for environmental matters. We also have a number of environmental matters for which we have not accrued loss contingencies because the risk of loss is not probable of a loss cannot be reasonably estimated, which are disclosed in the paragraphs below. We evaluate the potential liability related to 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 coal-fired generation units. Some of these matters could have material adverse impacts on the operation of the power stations; especially the stations that do not have SCR and FGD equipment installed to further control certain emissions. Currently, the coal-fired generation unit Beckjord Unit 6, in which **DP&L** has a 50% ownership interest, does not have such emission-control equipment installed. This unit is scheduled to be deactivated on June 1, 2015. **DPL** valued Beckjord Unit

6 at zero at the Merger date. **DP&L** is depreciating Unit 6 through December 2014 and does not believe that any additional accruals or impairment charges are needed as a result of this decision.

DP&L deactivated the coal units at Hutchings Station in September 2013 as part of a settlement with the USEPA discussed in more detail below.

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.

Clean Air Interstate Rule/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 NO_x emissions from existing power stations located in 27 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase began in 2009 and 2010 for NO_x and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions is scheduled 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 the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, CSAPR would have required significant reductions in SO_2 and NO_x emissions from covered sources, such as power stations in 28 eastern states. Once fully implemented in 2014, the rule would have required additional SO_2 emission reductions of 73% and additional NO_x 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. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that the 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 are to continue to serve as the governing program until the USEPA takes further action or the U.S. Congress intervenes. On October 5, 2012, the 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, which were denied. On June 24, 2013, the U.S. Supreme Court agreed to review the D.C. Circuit Court's decision to vacate CSAPR and heard oral arguments in the matter on December 10, 2013. Currently, 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 unit 6 will not operate on coal in 2015 due to implementation of the Mercury and Air Toxics Standards (MATS). If the USEPA issues 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.

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, on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Our affected EGUs must come into compliance with the new requirements by April 16, 2015, but may be granted an additional year to become compliant 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 January 31, 2013, the USEPA finalized a rule regulating emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers and process heaters at major and area source facilities. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulation contains emissions limitations, operating limitations and other requirements. **DP&L** expects to be in compliance with this rule and the costs are not currently expected to be material to **DP&L's** operations.

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, the USEPA redesignated Adams County, where Stuart and Killen are located, to attainment status. 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, including in counties where we have generating stations. 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.

The USEPA published the national ground level ozone standard on March 12, 2008, lowering the 8-hour level from 0.08 ppm to 0.075 ppm, which was upheld by the U.S. Circuit Court of Appeals in July 2013. No **DP&L** operations are currently located in non-attainment areas. The USEPA was expected to review the ozone NAAQS in 2013 but delayed such a review. Certain environmental groups have sued the USEPA in federal district court to force the USEPA to set a September 30, 2014 deadline for such review. It is generally expected that any revised standard resulting from such review would be more stringent than the current 0.075 ppm standard. In addition, in December 2013, eight northeastern states petitioned the USEPA to add nine upwind states, including Ohio, to the Ozone Transport Region, a group of states required to impose enhanced restrictions on ozone emissions. If the petition is granted, our facilities could be subject to such enhanced requirements.

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. Initial non-attainment designations were made July 25, 2013. Non-attainment areas will be required to meet the new standard by October 2018.

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 GHG 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, the 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, the USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under the USEPA's view, this is the final action that renders CO_2 and certain 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. Various industry groups and states petitioned the U.S. Supreme Court to review the D.C. Circuit Court's recent decision to uphold the USEPA's endangerment finding, its April 2010 GHG rule and the Tailoring Rule. On October 15, 2013, the U.S. Supreme Court agreed to review several related cases addressing the USEPA's authority to issue GHG Prevention of Significant Deterioration permits under Section 165 of the CAA. We cannot predict the outcome of this review. 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 September 20, 2013, the USEPA proposed revised GHG New Source Performance Standards for new electric generating units (EGUs) under CAA subsection 111(b), which would require new EGUs to limit the amount of CO_2 emitted per megawatt-hour. The proposal anticipates that affected coal-fired units would need to rely upon partial implementation of carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. Furthermore, President Obama directed the USEPA to propose new standards, regulations, or guidelines, as appropriate, to address GHG emissions from existing EGUs under CAA subsection 111(d) by June 1, 2014, and finalize them by June 1, 2015. These latter rules may focus on energy efficiency improvements at power stations. We cannot predict the effect of these proposed or forthcoming standards on **DP&L's** operations.

Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 14 million tons annually. Further GHG legislation or regulation implemented 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 effect 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 NO_x, 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 AEP Generation (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. The Conesville complaint was resolved in 2007 as part of a larger settlement with the USEPA. Conesville was required to install FGD and SCR at the unit by the end of 2010, and those retrofits have been completed. The Beckjord complaint was also resolved through litigation. There were no penalties or settlement agreements that affected Beckjord 6.

In June 2000, the USEPA issued an NOV to the **DP&L**-operated Stuart generating station (co-owned by **DP&L**, Duke Energy and AEP Generation) 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, the 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. 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. As a result of the cessation of operations at the Hutchings Station discussed in the next paragraph, **DP&L** believes that the USEPA is unlikely to pursue the NSR complaint.

As part of a settlement with the USEPA, **DP&L** signed a Consent Agreement and Final Order (CAFO) that was filed on September 26, 2013 and an Administrative Consent Agreement. Together, these two agreements resolved the opacity and particulate emissions NOV at the Hutchings Station and required that all six coal-fired units at Hutchings cease operating on coal by September 30, 2013, and included an immaterial penalty and the completion of a Supplemental Environmental Project of $0.2 million within one year. The units were disabled for coal operations prior to September 30, 2013.

DP&L also resolved all issues associated with the Ohio EPA NOV through a settlement signed October 4, 2013. The settlement included the payment of an immaterial penalty.

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. The USEPA is required pursuant to a settlement agreement to issue a final rule by April 17, 2014. We do not yet know the impact the final rules will have on our operations.

Clean Water Act – Regulation of Water Discharge
In December 2006, **DP&L** submitted a renewal application for the Stuart Station NPDES permit that was due to expire on June 30, 2007. The Ohio EPA issued a revised draft permit that was received on November 12, 2008. In September 2010, the USEPA formally objected to the November 12, 2008 revised permit due to questions regarding the basis for the alternate thermal limitation. At **DP&L's** request, a public hearing was held on March 23, 2011, where **DP&L** presented its position on the issue and provided written comments. 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 did not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit would 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 required **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, the 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, the 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 appeal process, the effects could be material on **DP&L's** operations.

In September 2009, the USEPA announced that it would 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. The proposed rule was released on June 7, 2013, with a deadline for a final rule on May 22, 2014, though such final rule's issuance is expected to be delayed. 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 January 2014, **DP&L** submitted an application for the renewal of the Hutchings Station NPDES permit which expires in July 2014. 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** installed sedimentation ponds as part of the runoff control measures to address this issue and worked with the various agencies to resolve their concerns. **DP&L** signed an Administrative Order from the USEPA on May 30, 2013. A final Consent Agreement and Final Order was executed on July 8, 2013, and the previously issued permit was reinstated by the Corps on October 29, 2013.

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. 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 the PRP group in performing an RI/FS. That summary judgment ruling was appealed on March 4, 2013 and the appeal is pending. **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.

Beginning in mid-2012, the USEPA began investigating whether explosive or other dangerous conditions exist under structures located at or near the South Dayton Dump landfill site. In October 2012, **DP&L** received a request from the PRP group's consultant to conduct additional soil and groundwater sampling on **DP&L's** service center property. After informal discussions with the USEPA, **DP&L** complied with this sampling request and the sampling was conducted in February 2013. On February 28, 2013, the plaintiffs group referenced above entered into an Administrative Settlement Agreement Consent Order (ASACO) that establishes procedures for further sub-slab testing under structures at the South Dayton Dump landfill site and remediation of vapor intrusion issues relating to trichloroethylene (TCE), percholorethylene (PCE), and methane. On April 16, 2013, the plaintiffs group filed a new complaint in the United States District Court for the Southern District of Ohio against **DP&L** and 34 other defendants alleging that they share liability for these costs. **DP&L** has opposed the allegations that it bears any responsibility under the February 2013 ASACO and will actively oppose any attempt that the plaintiffs group may have to expand the scope of the new complaint to resurrect issues dismissed by the Court in February 2013 under the first complaint. A motion to dismiss portions of this second complaint relating to alleged migration of chemicals from **DP&L** property to the landfill was denied February 18, 2014, as were motions filed by DP&L and others to dismiss other portions of the complaint that were viewed by defendants as identical to the allegations dismissed in the first complaint proceeding. The Judge found that there were differences in the allegations and is permitting those allegations to proceed.. Limited discovery has been permitted pending resolution of the motion including some depositions of former **DP&L** employees during 2013 and into 2014. DP&L cannot predict the outcome of this proceeding.

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 previously indicated that the official release date for a proposed rule was in April 2013, it has been delayed, likely until late 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. On March 14, 2013, **DP&L** received the final report on the inspection of the Killen Station ash pond inspection from the USEPA which included recommended actions. **DP&L** has submitted a response with its actions to the USEPA. **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 the USEPA has opposed. On January 29, 2014, the parties to the litigation entered into a consent decree setting forth the USEPA's obligation to sign, by December 19, 2014, a notice for publication in the Federal Register taking action on the Agency's proposed Subtitle D option. The decree does not require Subtitle D regulation of coal combustion byproducts – it only requires the Agency to decide by that date whether or not to adopt the Subtitle D option. 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 NPDES permit program and the station's storm water pollution prevention plan. The notice requested that **DP&L** respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on **DP&L's** results of operations, financial condition or cash flows.

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.

Note 17 – 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 seven coal-fired electric generating stations and is distributed to more than 515,000 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 308,000 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, we have increased the number of employees and resources assigned to manage the Competitive Retail segment and increased its marketing to customers. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. Intercompany sales from **DP&L** to DPLER are based on fixed-price contracts for each DPLER customer; the price approximates market prices for wholesale power at the inception of each customer's contract. **DP&L** started selling physical power to MC Squared during June 2012 and became their sole source of power in September, 2012 under the same terms as above. 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 Consolidated
Year ended December 31, 2013					
Revenues from external customers	$ 1,098.2	$ 511.6	$ 27.1	$ -	$ 1,636.9
Intersegment revenues	453.3	-	4.0	(457.3)	-
Total revenues	1,551.5	511.6	31.1	(457.3)	1,636.9
Fuel	362.5	-	4.2	-	366.7
Purchased power	381.9	459.7	1.1	(453.7)	389.0
Amortization of intangibles	-	-	7.1	-	7.1
Gross margin (a)	$ 807.1	$ 51.9	$ 18.7	$ (3.6)	$ 874.1
Depreciation and amortization	$ 140.2	$ 0.6	$ (7.9)	$ -	$ 132.9
Goodwill impairment (Note 18)	$ -	$ -	$ 306.3	$ -	$ 306.3
Fixed asset impairment	$ 86.0	$ -	$ (59.8)	$ -	$ 26.2
Interest expense	$ 37.2	$ 0.5	$ 86.9	$ (0.6)	$ 124.0
Income tax expense / (benefit)	$ 18.6	$ 4.2	$ (0.5)	$ -	$ 22.3
Net income / (loss)	$ 83.6	$ 6.6	$ (312.2)	$ -	$ (222.0)
Cash capital expenditures	$ 122.1	$ -	$ 2.3	$ -	$ 124.4
Total assets (end of year)	$ 3,313.1	$ 105.0	$ 1,675.8	$ (1,372.4)	$ 3,721.5

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

Successor

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
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 18)	$ -	$ -	$ 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.

Note 18 – 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.

As of October 1, 2013, **DPL** performed its annual goodwill impairment test at its DP&L reporting unit and recognized a goodwill impairment expense of $306.3 million. In performing the annual goodwill impairment test as of October 1, 2013, Step 1 of the test failed as the fair value of the reporting unit no longer exceeded its carrying amount due primarily to lower estimates of capacity prices in future years as well as lower dark spreads contributing to lower overall operating margins for the business. The fair value of the reporting unit was determined under the income approach using a discounted cash flow valuation model. The significant assumptions included within the discounted cash flow valuation model were capacity price curves, amount of the non-bypassable charge, commodity price curves, dispatching, valuation of regulatory assets and liabilities, discount rates and deferred income taxes. In Step 2, goodwill was determined to have an implied fair value of $317.0 million after the hypothetical purchase price allocation under the accounting guidance for business combinations.

DPL recognized a goodwill impairment expense of $1.817.2 million in 2012 at the DP&L reporting unit. During 2012, North American natural gas prices fell significantly compared to the previous year, which exerted downward pressure on wholesale power prices in the Ohio power market. These falling power prices compressed wholesale margins at **DP&L** and led to increased customer switching from **DP&L** to other CRES providers, including DPLER, who were offering retail prices lower than **DP&L's** standard service offer. In addition, several municipalities in **DP&L's** service territory passed ordinances allowing them to become government aggregators and contracted with CRES providers to provide generation service to the customers located within the municipal boundaries, further contributing to the switching trend. CRES providers also became more active in **DP&L's** service territory. These developments reduced **DP&L's** forecasted profitability, operating cash flows and liquidity. As a result, in September 2012, management lowered its previous forecasts of profitability and operating cash flows. Collectively, these events were considered an interim goodwill impairment indicator at the DP&L reporting unit. There were no interim impairment indicators identified for the goodwill at DPLER.

The goodwill associated with the Merger is not deductible for tax purposes. Accordingly, there is no cash tax or financial statement tax benefit related to the impairment. The Company's effective tax rates were impacted by the pretax impairment, however. The Company's effective tax rates were (11.2%) and (2.8%) for the years ended December 31, 2013 and 2012, respectively.

Note 19 – Fixed-asset Impairment

During the fourth quarter of 2013, the Company tested the recoverability of long-lived assets at Conesville, a 129 MW coal-fired station in Ohio jointly-owned by **DP&L**. Gradual decreases in power prices as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit failing step 1 of the annual goodwill impairment test were determined to be an impairment indicator for long-lived assets. The Company performed a long-lived asset impairment test and determined that the carrying amount of the asset group was not recoverable. 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. The Conesville asset group was determined to have zero fair value using discounted cash flows under the income approach. As a result, the Company recognized an asset impairment expense of $26.2 million. Conesville is reported in the Utility segment.

Note 20 – Selected Quarterly Information (Unaudited)

	For the 2011 periods ended (a):				
	Predecessor				Successor
$ in millions except per share amounts	March 31	June 30	September 30	November 27	December 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

(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.

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

FINANCIAL STATEMENTS

The Dayton Power and Light Company

Report of Independent Registered Public Accounting Firm

To the Board of Directors of The Dayton Power and Light Company

We have audited the accompanying balance sheets of The Dayton Power and Light Company (DP&L) as of December 31, 2013 and 2012, and the related statements of Results of Operations, Comprehensive Income/(Loss), Cash Flows, and Shareholders' Equity for the years ended December 31, 2013 and 2012.Our audit also included the consolidated financial statement schedule "Schedule II – Valuation and Qualifying Accounts" for the years ended December 31, 2013 and 2012. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these 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 audits 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 financial statements referred to above present fairly, in all material respects, the financial position of DP&L at December 31, 2013 and 2012, and the results of its operations and its cash flows for the years ended December 31, 2013 and 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 LLP
March 4, 2014
Louisville, Kentucky

Report of Independent Registered Public Accounting Firm

The Board of Directors
The Dayton Power and Light Company:

We have audited the accompanying statements of results of operations, comprehensive income / (loss), cash flows and shareholder's equity of The Dayton Power and Light Company (DP&L) for the year ended December 31, 2011. 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, 2011. These financial statements and financial statement schedule are the responsibility of DP&L's management. Our responsibility is to express an opinion on these financial statements and financial statement 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 of DP&L referred to above present fairly, in all material respects, the results of its operations and its cash flows for the year 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

	Year ended December 31,		
$ in millions	**2013**	2012	2011
Revenues	$ **1,551.5**	$ 1,531.8	$ 1,677.7
Cost of revenues:			
Fuel	**362.5**	354.9	380.6
Purchased power	**381.9**	309.5	401.6
Total cost of revenues	**744.4**	664.4	782.2
Gross margin	**807.1**	867.4	895.5
Operating expenses:			
Operation and maintenance	**362.1**	385.9	364.8
Depreciation and amortization	**140.2**	141.3	134.9
General taxes	**76.4**	74.4	75.9
Fixed asset impairment	**86.0**	80.8	-
Total operating expenses	**664.7**	682.4	575.6
Operating income	**142.4**	185.0	319.9
Other income / (expense), net			
Investment income	**2.0**	2.3	17.3
Interest expense	**(37.2)**	(39.1)	(38.2)
Other deductions	**(5.0)**	(1.9)	(1.6)
Total other expense, net	**(40.2)**	(38.7)	(22.5)
Earnings (loss) from operations before income tax	**102.2**	146.3	297.4
Income tax expense	**18.6**	55.1	104.2
Net income	**83.6**	91.2	193.2
Dividends on preferred stock	**0.9**	0.9	0.9
Earnings on common stock	$ **82.7**	$ 90.3	$ 192.3

See Notes to Financial Statements.

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

$ in millions	Year ended December 31, 2013	2012	2011
Net income	$ 83.6	$ 91.2	$ 193.2
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $0.9, $(0.2) and $4.3 for each respective period	(1.6)	0.5	(7.8)
Reclassification to earnings, net of income tax benefit / (expense) of $(0.7), $0.0 and $0.0 for each respective period	1.4	(0.1)	-
Total change in fair value of available-for-sale securities	(0.2)	0.4	(7.8)
Derivative activity:			
Change in derivative fair value, net of income tax benefit / (expense) of $(0.6), $1.6 and $0.5 for each respective period	1.0	(3.0)	(1.2)
Reclassification of earnings, net of income tax benefit / (expense) of $(2.5), $0.5 and $0.1 for each respective period	2.6	(3.4)	(0.2)
Total change in fair value of derivatives	3.6	(6.4)	(1.4)
Pension and postretirement activity:			
Prior service cost for the period, net of income tax benefit / (expense) of $(0.2), $(0.5) and $(0.4) for each respective period	0.5	0.8	0.5
Net loss for the period, net of income tax benefit / (expense) of $(1.9), $0.8 and $5.4 for each respective period	4.3	(1.5)	(8.0)
Reclassification to earnings, net of income tax benefit / (expense) of $(1.9), $(1.5) and $(1.5) for each respective period	3.8	2.7	2.3
Total change in unfunded pension and postretirement obligation	8.6	2.0	(5.2)
Other comprehensive income / (loss)	12.0	(4.0)	(14.4)
Net comprehensive income	$ 95.6	$ 87.2	$ 178.8

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF CASH FLOWS

$ in millions	Year ended December 31, 2013	2012	2011
Cash flows from operating activities:			
Net income	$ **83.6**	$ 91.2	$ 193.2
Adjustments to reconcile Net income (loss) to Net cash from operating activities			
Depreciation and amortization	**140.2**	141.3	134.9
Deferred income taxes	**(16.8)**	3.6	50.7
Gain on liquidation of DPL stock, held in trust	**-**	-	(14.6)
Fixed-asset impairment	**86.0**	80.8	-
Recognition of deferred SECA revenue	**-**	(17.8)	-
Changes in certain assets and liabilities:			
Accounts receivable	**15.0**	20.9	5.3
Inventories	**27.2**	14.2	(11.8)
Prepaid taxes	**0.4**	0.1	8.1
Taxes applicable to subsequent years	**(1.8)**	5.2	(9.0)
Deferred regulatory costs, net	**7.8**	(1.5)	(12.6)
Accounts payable	**(5.9)**	(15.3)	7.1
Accrued taxes payable	**(9.1)**	(8.5)	15.2
Accrued interest payable	**(3.4)**	5.2	0.2
Pension, retiree and other benefits	**1.8**	28.5	(24.0)
Unamortized investment tax credit	**(2.5)**	(2.5)	(2.5)
Other	**12.8**	(5.6)	24.0
Net cash from operating activities	**335.3**	339.8	364.2
Cash flows from investing activities:			
Capital expenditures	**(122.1)**	(195.5)	(204.5)
Decrease / (increase) in restricted cash	**(2.3)**	2.9	(3.8)
Purchase of renewable energy credits	**(3.9)**	(5.4)	(4.4)
Proceeds from sale of property - other	**0.8**	0.2	-
Insurance proceeds	**14.2**	-	-
Proceeds from liquidation of DPL stock, held in trust	**-**	-	26.9
Other investing activities, net	**(1.2)**	0.3	0.8
Net cash from investing activities	**(114.5)**	(197.5)	(185.0)

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

$ in millions	Year ended December 31, 2013	2012	2011
Cash flows from financing activities			
Dividends paid on common stock to parent	**(190.0)**	(145.0)	(220.0)
Dividends paid on preferred stock	**(0.9)**	(0.9)	(0.9)
Retirement of long-term debt	**(470.1)**	(0.1)	(0.1)
Cash contribution from parent	**-**	-	20.0
Issuance of long-term debt	**445.0**	-	-
Deferred financing costs	**(10.4)**	-	-
Borrowings from revolving credit facilities	**-**	-	50.0
Repayment of borrowings from revolving credit facilities	**-**	-	(50.0)
Net cash from financing activities	**(226.4)**	(146.0)	(201.0)
Cash and cash equivalents:			
Net change	**(5.6)**	(3.7)	(21.8)
Balance at beginning of period	**28.5**	32.2	54.0
Cash and cash equivalents at end of period	**$ 22.9**	$ 28.5	$ 32.2
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	**$ 41.5**	$ 35.1	$ 39.2
Income taxes (refunded) / paid, net	**$ (20.3)**	$ 61.9	$ 13.9
Non-cash financing and investing activities:			
Accruals for capital expenditures	**$ 14.7**	$ 16.7	$ 26.5
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, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22.9	$ 28.5
Restricted funds	13.0	10.7
Accounts receivable, net (Note 3)	147.5	160.0
Inventories (Note 3)	81.7	108.9
Taxes applicable to subsequent years	68.5	66.7
Regulatory assets, current (Note 4)	20.8	18.3
Other prepayments and current assets	32.5	33.0
Total current assets	386.9	426.1
Property, plant and equipment:		
Property, plant and equipment	5,105.3	5,249.0
Less: Accumulated depreciation and amortization	(2,448.1)	(2,516.3)
	2,657.2	2,732.7
Construction work in process	60.9	87.8
Total net property, plant and equipment	2,718.1	2,820.5
Other non-current assets:		
Regulatory assets, non-current (Note 4)	159.7	185.5
Intangible assets, net of amortization (Note 1)	8.3	9.0
Other deferred assets	40.1	23.1
Total other non-current assets	208.1	217.6
Total Assets	$ 3,313.1	$ 3,464.2

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions		December 31, 2013		December 31, 2012
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities:				
Current portion - long-term debt (Note 6)	$	0.2	$	570.4
Accounts payable		73.9		79.1
Accrued taxes		81.0		92.2
Accrued interest		9.6		13.1
Customer security deposits		33.1		35.2
Regulatory liabilities, current (Note 4)		-		0.1
Other current liabilities		59.7		52.1
Total current liabilities		257.5		842.2
Non-current liabilities:				
Long-term debt (Note 6)		876.9		332.7
Deferred taxes (Note 7)		632.3		652.0
Taxes payable		76.5		66.0
Regulatory liabilities, non-current (Note 4)		121.1		117.3
Pension, retiree and other benefits (Note 8)		51.6		61.6
Unamortized investment tax credit		24.9		27.4
Other deferred credits		45.4		43.0
Total non-current liabilities		1,828.7		1,300.0
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		0.4		0.4
50,000,000 shares authorized, 41,172,173 shares issued and outstanding				
Other paid-in capital		803.5		803.3
Accumulated other comprehensive loss		(26.7)		(38.7)
Retained earnings		426.8		534.1
Total common shareholder's equity		1,204.0		1,299.1
Total Liabilities and Shareholder's Equity	$	3,313.1	$	3,464.2

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	$ 782.5	$ (20.3)	$ 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	803.2	(34.7)	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	803.3	(38.7)	534.1	1,299.1
Year ended December 31, 2013						
Total comprehensive income (loss)				12.0	83.6	95.6
Common stock dividends					(190.0)	(190.0)
Preferred stock dividends					(0.9)	(0.9)
Other			0.2			0.2
Ending balance	41,172,173	$ 0.4	$ 803.5	$ (26.7)	$ 426.8	$ 1,204.0

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

See Notes to Financial Statements.

Note 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. Beginning in 2001, Ohio law gave Ohio consumers the right to choose the electric generation supplier from whom they purchase retail generation service, however distribution and transmission retail service are still regulated. **DP&L** has exclusive right to provide such service to its more than 515,000 customers located in West Central Ohio. Additionally, **DP&L** offers retail SSO electric service to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio and generates electricity at seven coal-fired power stations. Beginning in 2014, **DP&L** no longer provides 100% of the generation for its SSO customers. Principal industries located in **DP&L's** service territory include automotive, food processing, paper, plastic, manufacturing and defense. **DP&L's** sales reflect the general economic conditions, seasonal weather patterns of the area and the market price of electricity. **DP&L** sells any excess energy and capacity into the wholesale market. **DP&L** also sells electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

DP&L filed a generation separation application at the end of December 2013, as required in its ESP order, with the PUCO and on February 25, 2013, filed a supplemental application. In the supplemental application, **DP&L** reaffirmed its commitment to separate the generation assets on or before May 31, 2017. **DP&L** continues to look at multiple options to effectuate the separation including transfer into a new unregulated affiliate of **DPL** or through a sale.

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 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 1,218 people as of December 31, 2013. Approximately 62% 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.

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 $1.5 million, $4.0 million, and $4.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

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

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

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

At December 31, 2013, **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.

During the fourth quarter of 2013, the Company tested the recoverability of long-lived assets at certain generating stations. See Note 15 for more information. Gradual decreases in power prices as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit of **DPL** failing step 1 of the annual goodwill impairment test were collectively determined to be an impairment indicator. The effect of this impairment will be to reduce future depreciation related to these stations by approximately $3.8 million per year.

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 years ended December 31, 2013 and 2012 was a reduction of approximately $5.4 million and $1.8 million, respectively.

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 4.4% in 2013, 4.2% in 2012 and 2.6% in 2011.

The following is a summary of **DP&L's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2013 and December 31, 2012:

	December 31,			
$ in millions	**2013**	**Composite Rate**	2012	Composite Rate
Regulated:				
Transmission	$ 388.3	2.3%	$ 380.9	2.4%
Distribution	1,528.2	3.5%	1,480.7	3.4%
General	111.1	6.2%	100.0	5.4%
Non-depreciable	60.8	N/A	60.1	N/A
Total regulated	2,088.4		2,021.7	
Unregulated:				
Production / Generation	3,002.1	5.2%	3,210.8	4.9%
Non-depreciable	14.8	N/A	16.5	N/A
Total unregulated	3,016.9		3,227.3	
Total property, plant and equipment in service	$ 5,105.3	4.4%	$ 5,249.0	4.2%

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	
Balance at December 31, 2011	$ 18.8
Calendar 2012	
Accretion expense	0.9
Settlements	(0.4)
Estimated cash flow revisions	(0.1)
Balance at December 31, 2012	19.2
Calendar 2013	
Accretion expense	1.0
Settlements	(0.3)
Balance at December 31, 2013	$ 19.9

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 $114.9 million and $112.1 million in estimated costs of removal at December 31, 2013 and 2012, 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

$ in millions		
Balance at December 31, 2011	$	112.4
Calendar 2012		
Additions		10.1
Settlements		(10.4)
Balance at December 31, 2012		112.1
Calendar 2013		
Additions		22.0
Settlements		(19.2)
Balance at December 31, 2013	$	114.9

Regulatory Accounting
As a regulated utility, we apply the provisions of FASC 980 *"Regulated Operations,"* which gives recognition to the ratemaking and accounting practices of the PUCO and the FERC. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory assets can also represent performance incentives permitted by the regulator, such as with our CCEM energy efficiency program. Regulatory assets have been included as allowable costs for ratemaking purposes, as authorized by the PUCO or established regulatory practices. Regulatory liabilities generally represent obligations to make refunds or future rate reductions to customers for previous over collections or the deferral of revenues collected for costs that **DPL** expects to incur in the future.

The deferral of costs (as regulatory assets) is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific orders from the PUCO or FERC, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed probable, related regulatory assets would be required to be expensed in current period earnings. Our regulatory assets and liabilities have been created pursuant to a specific order of the PUCO or FERC or established regulatory practices, such as other utilities under the jurisdiction of the PUCO or FERC being granted recovery of similar costs. It is probable, but not certain, that these regulatory assets will be recoverable, subject to PUCO or FERC approval. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 4 for more information about 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.

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: available-for-sale and held-to-maturity. 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, 2013, 2012 and 2011 were $50.5 million, $50.5 million and $53.7 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, discussed in Note 2, vesting of all share-based awards was accelerated as of the Merger date, and none are in existence at December 31, 2013 or 2012.

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.

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. 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 $18.8 million and $17.7 million at December 31, 2013 and 2012, 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 certain assumptions. 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.

Effective December 22, 2013, AES US Services, LLC (the "Service Company") began providing services including accounting, legal, human resources, information technology and other services of a similar nature on behalf of the AES U.S. Strategic Business Unit ("U.S. SBU"). The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable distribution. This includes ensuring that the regulatory utilities served, including **DP&L**, are not subsidizing costs incurred for the benefit of non-regulated businesses.

The following table provides a summary of these transactions:

	Years ended December 31,		
$ in millions	2013	2012	2011
DP&L revenues:			
Sales to DPLER (a)	$ 345.8	$ 350.8	$ 327.0
Sales to MC Squared (a)	$ 108.1	$ 40.0	$ -
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC (b)	$ (2.9)	$ (2.6)	$ (3.1)
Expense recoveries for services provided to DPLER (c)	$ 5.2	$ 4.0	$ 4.6
DP&L Customer security deposits:			
Deposits received from DPLER (d)	$ 19.2	$ 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

Offsetting Assets and Liabilities
In December 2011, the FASB issued ASU 2011-11 "Disclosures about Offsetting Assets and Liabilities" (ASU 2011-11) effective for interim and annual reporting periods beginning on or after January 1, 2013. We adopted this ASU on January 1, 2013. This standard was clarified by ASU 2013-01 "Scope Clarification of Disclosures about Offsetting Assets and Liabilities", which also was effective on January 1, 2013. This standard updates FASC Topic 210 "Balance Sheet." ASU 2011-11 updates the disclosures for financial instruments and derivatives to provide more transparent information around the offsetting of assets and liabilities. Entities are required to disclose both gross and net information about both instruments and transactions eligible for offset in the statement of financial position and/or subject to an agreement similar to a master netting agreement. In ASU 2013-01, 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. We adopted this rule, which resulted in enhanced disclosures, but it did not have an effect on our overall results of operations, financial position or cash flows.

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

Comprehensive Income
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. This ASU does not change the current requirements for reporting net income or OCI in financial statements. However, this ASU requires an entity to provide information about the amounts reclassified out of AOCI 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 AOCI by the respective line items of net income, but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. We adopted this rule, which resulted in enhanced disclosures, but it did not have an effect on our overall results of operations, financial position or cash flows.

Note 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.

Note 3 – Supplemental Financial Information

$ in millions	December 31, 2013	2012
Accounts receivable, net		
Unbilled revenue	$ **47.2**	$ 48.1
Customer receivables	**58.2**	62.0
Amounts due from partners in jointly-owned stations	**15.8**	19.7
Coal sales	**-**	1.6
Other	**27.2**	29.5
Provisions for uncollectible accounts	**(0.9)**	(0.9)
Total accounts receivable, net	$ **147.5**	$ 160.0
Inventories		
Fuel and limestone	$ **42.9**	$ 67.3
Plant materials and supplies	**37.0**	39.8
Other	**1.8**	1.8
Total inventories, at average cost	$ **81.7**	$ 108.9

Accumulated Other Comprehensive Income (Loss)

The amounts reclassified out of Accumulated Other Comprehensive Income / (Loss) by component during the years ended December 31, 2013, 2012 and 2011 are as follows:

Details about Accumulated Other Comprehensive Income / (Loss) Components $ in millions	**Affected line item in the Statements of Operations**	**Years ended December 31,** **2013**	2012	2011
Gains and losses on Available-for-sale securities activity (Note 9):				
	Other income / (deductions)	$ **2.1**	$ (0.1)	$ -
	Total before income taxes	**2.1**	(0.1)	-
	Tax expense	**(0.7)**	-	-
	Net of income taxes	**1.4**	(0.1)	-
Gains and losses on cash flow hedges (Note 10):				
	Interest expense	**(2.1)**	(2.5)	(2.4)
	Revenue	**2.2**	0.3	1.1
	Purchased power	**5.0**	(1.6)	1.0
	Total before income taxes	**5.1**	(3.8)	(0.3)
	Tax expense	**(2.5)**	0.4	0.1
	Net of income taxes	**2.6**	(3.4)	(0.2)
Amortization of defined benefit pension items (Note 8):				
	Reclassification to Other income / (deductions)	**5.7**	4.1	2.8
	Tax benefit	**(1.9)**	(1.4)	(0.5)
	Net of income taxes	**3.8**	2.7	2.3
Total reclassifications for the period, net of income taxes		$ **7.8**	$ (0.8)	$ 2.1

The changes in the components of Accumulated Other Comprehensive Income / (Loss) during the years ended December 31, 2013 and 2012 are as follows:

$ in millions	Gains / (losses) on available-for-sale securities	Gains / (losses) on cash flow hedges	Change in unfunded pension obligation	Total
Balance January 1, 2012	$ 0.6	$ 9.0	$ (44.3)	$ (34.7)
Other comprehensive income / (loss) before reclassifications	0.5	(3.0)	(0.7)	(3.2)
Amounts reclassified from accumulated other comprehensive income / (loss)	(0.1)	(3.4)	2.7	(0.8)
Net current period other comprehensive income / (loss)	0.4	(6.4)	2.0	(4.0)
Balance December 31, 2012	1.0	2.6	(42.3)	(38.7)
Other comprehensive income / (loss) before reclassifications	**(1.6)**	**1.0**	**4.8**	**4.2**
Amounts reclassified from accumulated other comprehensive income / (loss)	**1.4**	**2.6**	**3.8**	**7.8**
Net current period other comprehensive income / (loss)	**(0.2)**	**3.6**	**8.6**	**12.0**
Balance December 31, 2013	**$ 0.8**	**$ 6.2**	**$ (33.7)**	**$ (26.7)**

Note 4 – Regulatory Matters

In accordance with FASC 980, we have recognized total regulatory assets of $180.5 million and $203.8 million as of December 31, 2013 and 2012, respectively and total regulatory liabilities of $121.1 million and $117.4 million as of December 31, 2013 and 2012, respectively. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 1 for accounting policies regarding Regulatory Assets and Liabilities.

The following table presents **DP&L's** Regulatory assets and liabilities:

$ in millions	Type of Recovery (a)	Amortization Through	December 31, 2013	2012
Regulatory assets, current:				
Transmission costs	F	2014	$ 2.6	$ 7.0
Fuel and purchased power recovery costs	C	2014	6.3	11.3
Energy efficiency program	F	2014	7.7	-
Other miscellaneous		2014	4.2	-
Total regulatory assets, current			$ 20.8	$ 18.3
Regulatory assets, non-current:				
Deferred recoverable income taxes	B/C	Ongoing	$ 32.4	$ 35.1
Pension benefits	C	Ongoing	77.1	88.9
Unamortized loss on reacquired debt	C	Various	10.9	11.9
Deferred storm costs	D	Undetermined	25.6	24.4
CCEM smart grid and advanced metering infrastructure costs	D		6.6	6.6
Energy efficiency program costs	F	2014	-	5.2
Consumer education campaign	D	Undetermined	3.0	3.0
Retail settlement system costs	D	Undetermined	3.1	3.1
Other miscellaneous		Undetermined	1.0	7.3
Total regulatory assets, non-current			$ 159.7	$ 185.5
Regulatory liabilities, current:				
Other miscellaneous			$ -	$ 0.1
Total regulatory liabilities, current			$ -	$ 0.1
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated			$ 115.0	$ 112.1
Postretirement benefits			5.6	5.0
Other miscellaneous			0.5	0.2
Total regulatory liabilities, non-current			$ 121.1	$ 117.3

(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

Transmission 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.

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. As part of the PUCO approval process, an outside auditor reviews fuel costs and the fuel procurement process. An audit of 2012 fuel costs occurred in 2013. On June 12, 2013, we received a report from that external auditor recommending a pre-tax disallowance of $5.3 million of costs; a portion of which was recorded as a reserve against the regulatory asset. A hearing in this case was held on December 9, 2013 and we expect an order in the case in the second quarter of 2014.

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. Due to the short-term nature of the remaining amortization period, the balance was reclassified to current regulatory assets in 2013 and is included in *Other miscellaneous* in the table above.

Deferred storm costs relate to costs incurred to repair the damage caused to **DP&L's** transmission and distribution equipment by major storms in 2008, 2011 and 2012. **DP&L** filed an application with the PUCO in 2012 to recover these costs. There has been disagreement among **DP&L**, the PUCO staff and other intervenors in the case as to what portion of these storm costs should be recoverable. We continue to believe the costs we have deferred are probable for recovery based on established regulatory practices in the state of Ohio. A hearing is scheduled for this matter in March 2014. The outcome of this case is uncertain at this time.

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.

Energy efficiency program costs represent costs incurred to develop and implement various 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 an annual true-up for any over/under recovery of costs.

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 costs Please see "*Regulatory Assets – Fuel and purchased power recovery costs*" above.

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.

Note 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, 2013, **DP&L** had $24.0 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 the coal portion of our wholly-owned coal fired Hutchings Station at December 31, 2013, 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	$ 69	$ -	No
Conesville Unit 4	16.5	129	20	-	-	Yes
East Bend Station	31.0	186	-	-	-	Yes
Killen Station	67.0	402	622	303	4	Yes
Miami Fort Units 7 and 8	36.0	368	361	152	1	Yes
Stuart Station	35.0	808	744	307	16	Yes
Zimmer Station	28.1	365	1,098	657	3	Yes
Transmission (at varying percentages)			98	60	-	
Total		2,465	$ 3,019	$ 1,548	$ 24	
Wholly-owned production unit						
Hutchings Station	100.0	-	$ -	$ -	$ -	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.

As part of a settlement with the USEPA regarding Hutchings Station, **DP&L** signed an Administrative Consent Order and a Consent Agreement and Final Order (CAFO) that was filed on September 26, 2013. Together, these two agreements resolved the opacity and particulate emissions NOV at the Hutchings Station and required that all six coal-fired units at Hutchings cease operating on coal by September 30, 2013, and included an immaterial penalty and the completion of a Supplemental Environmental Project of $0.2 million within one year. The units were disabled for coal operations prior to September 30, 2013. We do not believe that any additional accruals are needed related to the Hutchings Station. These agreements do not affect Hutchings unit 7, a small combustion turbine.

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 fair market value different than **DP&L's** carrying value. Since **DP&L** did not apply push down accounting, this valuation did not affect the carrying value of these stations' valuation at **DP&L**. In the fourth quarter of 2013, **DP&L** performed an impairment review of its stations and recorded an impairment of $86.0 million related to two of its stations, Conesville and East Bend. 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 these impairments.

Note 6 – Debt Obligations

Long-term debt is as follows:

Long-term debt

$ in millions	**December 31, 2013**	December 31, 2012
First mortgage bonds due in September 2016 - 1.875%	**$ 445.0**	$ -
Pollution control series due in January 2028 - 4.7%	**35.3**	35.3
Pollution control series due in January 2034 - 4.8%	**179.1**	179.1
Pollution control series due in September 2036 - 4.8%	**100.0**	100.0
Pollution control series due in November 2040 - variable rates: 0.05% - 0.24% and 0.04% - 0.26% (a)	**100.0**	-
U.S. Government note due in February 2061 - 4.2%	**18.2**	18.3
Capital lease obligations	**-**	0.1
Unamortized debt discount	**(0.7)**	(0.1)
Total long-term debt	**$ 876.9**	$ 332.7

(a) - range of interest rates for the twelve months ended December 31, 2013 and December 31, 2012, respectively.

Current portion - long-term debt

$ in millions	**December 31, 2013**	December 31, 2012
First mortgage bonds due in October 2013 - 1.875%	**$ -**	$ 470.0
Pollution control series due in November 2040 - variable rates: 0.05% - 0.24% and 0.04% - 0.26% (a)	**-**	100.0
U.S. Government note due in February 2061 - 4.2%	**0.1**	0.1
Capital lease obligations	**0.1**	0.3
Total current portion - long-term debt	**$ 0.2**	$ 570.4

(a) - range of interest rates for the twelve months ended December 31, 2013 and December 31, 2012, respectively.

At December 31, 2013, maturities of long-term debt, including capital lease obligations, are summarized as follows:

Due within the twelve months ending December 31, $ in millions		
2014	$	0.2
2015		0.1
2016		445.1
2017		0.1
2018		0.1
Thereafter		432.2
		877.8
Unamortized discount		(0.7)
Total long-term debt	$	877.1

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 two standby letters of credit issued by JPMorgan Chase Bank, N.A. **DP&L** amended these standby letters of credit on May 31, 2013 and extended the stated maturities to June 2018. These amended facilities are irrevocable, have no subjective acceleration clauses and remain subject to terms and conditions that are substantially similar to those of the pre-existing facilities. Fees associated with this letter of credit facility were not material during the years ended December 31, 2013, 2012 and 2011.

On April 20, 2010, **DP&L** entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. The agreement provided **DP&L** with the ability to increase the size of the facility by an additional $50.0 million. This agreement, originally for a three year term expiring on April 20, 2013, was extended through May 31, 2013 pursuant to an amendment dated April 11, 2013. **DP&L** had no outstanding borrowings under this credit facility at December 31, 2012 or at the termination of the agreement in May 2013. Fees associated with this revolving credit facility were not material during the years ended December 31, 2013, 2012 and 2011. This facility also contained a $50.0 million letter of credit sublimit. **DP&L** had no outstanding letters of credit against the facility at December 31, 2012 or at the termination of the agreement in May 2013.

On August 24, 2011, **DP&L** entered into a $200.0 million unsecured revolving credit agreement with a syndicated bank group. This agreement was for a four year term expiring on August 24, 2015 and provided **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 at the termination of the agreement in May 2013. Fees associated with this revolving credit facility were not material during the years ended December 31, 2013 and 2012 or the five months ended December 31, 2011. This facility also contains a $50.0 million letter of credit sublimit. **DP&L** had no outstanding letters of credit against the facility at December 31, 2012 or at the termination of the agreement in May 2013.

On May 10, 2013, **DP&L** terminated both of the unsecured revolving credit agreements mentioned above and concurrently closed a new $300.0 million unsecured revolving credit agreement with a syndicated bank group. This new $300.0 million facility has a five year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature which provides **DP&L** the ability to increase the size of the facility by an additional $100.0 million. The other terms and conditions of this new revolving credit facility are substantially similar to those of the pre-existing **DP&L** revolving credit facilities. **DP&L** had no outstanding borrowings under this facility at December 31, 2013. At December 31, 2013, there was a letter of credit in the amount of $0.4 million outstanding, with the remaining $299.6 million available to **DP&L**. Fees associated with this revolving credit facility were not material during the year ended December 31, 2013.

DP&L's prior unsecured revolving credit agreements and **DP&L's** standby letters of credit had one financial covenant which measured Total Debt to Total Capitalization. The Total Debt to Total Capitalization ratio is calculated, at the end of each fiscal quarter, by dividing total debt at the end of the quarter by total capitalization at the end of the quarter. **DP&L's** new unsecured revolving credit agreement and **DP&L's** amended standby letters of credit maintain the Total Debt to Total Capitalization financial covenant and add the EBITDA to Interest Expense ratio as a second financial covenant. The EBITDA to Interest Expense ratio is calculated, at the end of each fiscal quarter, by dividing EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period.

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 September 19, 2013, **DP&L** closed a $445.0 million issuance of senior secured first mortgage bonds. These new bonds mature on September 15, 2016, and are secured by **DP&L's** First & Refunding Mortgage. On October 1, 2013, **DP&L** used the net proceeds of these new bonds, along with cash on hand, to redeem, at par value, the $470.0 million of first mortgage bonds that matured on October 1, 2013.

Substantially all property, plant and equipment of **DP&L** is subject to the lien of the First and Refunding Mortgage.

Note 7 – Income Taxes

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

$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011
Computation of tax expense			
Federal income tax expense / (benefit)[a]	$ **35.5**	$ 50.9	$ 103.8
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**0.3**	(2.0)	1.4
Depreciation of AFUDC - Equity	**(2.5)**	3.0	(3.2)
Investment tax credit amortized	**(2.5)**	(2.5)	(2.5)
Section 199 - domestic production deduction	**(4.1)**	(2.5)	(4.9)
Non-deductible merger-related compensation	**-**	0.6	3.6
Accrual (settlement) for open tax years	**(8.8)**	-	-
ESOP	**-**	-	13.6
Compensation and benefits	**-**	-	(5.3)
Other, net[b]	**0.7**	7.6	(2.3)
Total tax expense	$ **18.6**	$ 55.1	$ 104.2
Components of Tax Expense			
Federal - current	$ **38.6**	$ 52.1	$ 54.9
State and Local - current	**(0.1)**	1.0	0.9
Total current	**38.5**	53.1	55.8
Federal - deferred	**(20.4)**	4.7	47.1
State and local - deferred	**0.5**	(2.7)	1.3
Total deferred	**(19.9)**	2.0	48.4
Total tax expense	$ **18.6**	$ 55.1	$ 104.2

$ in millions	December 31, 2013	December 31, 2012
Net non-current Assets / (Liabilities)		
Depreciation / property basis	$ **(607.1)**	$ (622.1)
Income taxes recoverable	**(11.4)**	(12.3)
Regulatory assets	**(15.6)**	(20.6)
Investment tax credit	**8.8**	9.6
Compensation and employee benefits	**(0.2)**	0.3
Other	**(6.8)**	(6.9)
Net non-current liabilities	$ **(632.3)**	$ (652.0)
Net current Assets / (Liabilities) [(c)]		
Other	$ **(5.0)**	$ 2.0
Net current assets / (liabilities)	$ **(5.0)**	$ 2.0

(a) The statutory tax rate of 35% was applied to pre-tax earnings.
(b) Includes expense of $1.1 million, $7.6 million and benefit of $2.4 million in the years ended December 31, 2013, 2012 and 2011, 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, postemployment benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011
Tax expense / (benefit)	$ **7.0**	$ (0.8)	$ (7.2)

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	
Balance at December 31, 2011	$ 25.0
Calendar 2012	
Tax positions taken during prior period	(6.3)
Tax positions taken during current period	(0.4)
Balance at December 31, 2012	18.3
Calendar 2013	
Tax positions taken during prior period	(0.1)
Lapse of Statute of Limitations	(6.9)
Settlement with taxing authorities	(2.5)
Balance at December 31, 2013	$ 8.8

Of the December 31, 2013 balance of unrecognized tax benefits, $8.8 million is due to uncertainty in the timing of deductibility.

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, 2013**	Year ended December 31, 2012	Year ended December 31, 2011
Liability	**$ 0.2**	$ 0.8	$ 0.9

Amounts in Statement of Operations

$ in millions	**Year ended December 31, 2013**	Year ended December 31, 2012	Year ended December 31, 2011
Expense / (benefit)	**$ (0.6)**	$ (0.1)	$ 0.6

Following is a summary of the tax years open to examination by major tax jurisdiction:
U.S. Federal – 2010 and forward
State and Local – 2010 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months other than those subject to expiring statutes of limitations.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The results of the examination were approved by the Joint Committee on Taxation on January 18, 2013. As a result of the examination, **DPL** received a refund of $19.9 million and recorded a $1.2 million reduction to income tax expense.

Note 8 – 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. Effective December 22, 2013, certain employees of **DP&L** became employees of the Service Company of the US SBU. Employees that transferred from **DP&L** to the Service Company maintain their previous eligibility to participate in the **DP&L** pension plan.

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 provided a supplemental retirement benefit to participants by crediting an account established for each participant in accordance with the Plan requirements. We designated 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 could change his or her hypothetical investment fund selection at specified times. If a participant did not elect a hypothetical investment fund(s), then we selected 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 2012 and 2011 contributions were calculated and paid in March 2013 and 2012, respectively. The SEDCRP was terminated by the Board of Directors as of December 31, 2012. We also have an immaterial unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives.

We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. There were no contributions during the years ended December 31, 2013 and 2012. **DP&L** made a discretionary contribution of $40.0 million during the year ended December 31, 2011.

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. 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 the changes in our pension and postemployment benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2013 and 2012. 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 postemployment include both health and life insurance benefits.

$ in millions	**Pension**	
	Years ended December 31,	
	2013	2012
Change in benefit obligation		
Benefit obligation at beginning of period	$ **395.6**	$ 365.2
Service cost	**7.2**	6.2
Interest cost	**15.6**	17.3
Plan amendments	**-**	-
Actuarial (gain) / loss	**(26.5)**	29.1
Benefits paid	**(21.4)**	(22.2)
Benefit obligation at end of period	**370.5**	395.6
Change in plan assets		
Fair value of plan assets at beginning of period	**361.4**	335.9
Actual return on plan assets	**8.7**	46.2
Contributions to plan assets	**0.4**	1.5
Benefits paid	**(21.4)**	(22.2)
Fair value of plan assets at end of period	**349.1**	361.4
Funded status of plan	$ **(21.4)**	$ (34.2)

$ in millions	Postretirement	
	Years ended December 31,	
	2013	2012
Change in benefit obligation		
Benefit obligation at beginning of period	$ **22.4**	$ 21.7
Service cost	**0.2**	0.1
Interest cost	**0.8**	0.9
Actuarial (gain) / loss	**(2.2)**	1.2
Benefits paid	**(1.5)**	(1.7)
Medicare Part D reimbursement	**-**	0.2
Benefit obligation at end of period	**19.7**	22.4
Change in plan assets		
Fair value of plan assets at beginning of period	**4.2**	4.5
Actual return on plan assets	**-**	0.2
Contributions to plan assets	**1.0**	1.2
Benefits paid	**(1.5)**	(1.7)
Fair value of plan assets at end of period	**3.7**	4.2
Funded status of plan	$ **(16.0)**	$ (18.2)

$ in millions	Pension		Postretirement	
	December 31,		December 31,	
	2013	2012	**2013**	2012
Amounts recognized in the Balance sheets				
Current liabilities	$ **(0.4)**	$ (0.4)	$ **(0.5)**	$ (0.6)
Non-current liabilities	**(21.0)**	(33.8)	**(15.5)**	(17.6)
Net liability at Year ended December 31,	$ **(21.4)**	$ (34.2)	$ **(16.0)**	$ (18.2)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost	$ **16.3**	$ 19.0	$ **0.7**	$ 0.8
Net actuarial loss / (gain)	**115.1**	136.1	**(6.9)**	(5.7)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	$ **131.4**	$ 155.1	$ **(6.2)**	$ (4.9)
Recorded as:				
Regulatory asset	$ **76.3**	$ 88.0	$ **-**	$ 0.5
Regulatory liability	**-**	-	**(5.2)**	(5.0)
Accumulated other comprehensive income	**55.1**	67.1	**(1.0)**	(0.4)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	$ **131.4**	$ 155.1	$ **(6.2)**	$ (4.9)

The accumulated benefit obligation for our defined benefit pension plans was $359.8 million and $382.5 million at December 31, 2013 and 2012, respectively.

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

Net Periodic Benefit Cost - Pension

$ in millions	Years ended December 31, 2013	2012	2011
Service cost	$ 7.2	$ 6.2	$ 5.0
Interest cost	15.6	17.3	17.0
Expected return on assets[(a)]	(23.6)	(22.7)	(24.5)
Amortization of unrecognized:			
Actuarial gain	9.3	8.8	8.0
Prior service cost	2.8	2.8	2.1
Net periodic benefit cost before adjustments	11.3	12.4	7.6
Settlement Expense	-	0.6	-
Net periodic benefit cost after adjustments	$ 11.3	$ 13.0	$ 7.6

(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 $351.2 million in 2013, $346.0 million in 2012, and $335.0 million in 2011.

Net Periodic Benefit Cost / (Income) - Postretirement

$ in millions	Years ended December 31, 2013	2012	2011
Service cost	$ 0.2	$ 0.1	$ 0.1
Interest cost	0.8	0.9	1.0
Expected return on assets	(0.2)	(0.3)	(0.3)
Amortization of unrecognized:			
Actuarial loss	(0.7)	(0.9)	(1.1)
Prior service credit	0.1	0.1	0.1
Net periodic benefit cost / (income) before adjustments	$ 0.2	$ (0.1)	$ (0.2)

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

Pension

$ in millions	Years ended December 31, 2013	2012	2011
Net actuarial loss / (gain)	$ (11.7)	$ 5.2	$ 22.8
Prior service cost	-	-	7.1
Reversal of amortization item:			
Net actuarial loss	(9.3)	(9.4)	(8.0)
Prior service cost	(2.8)	(2.8)	(2.0)
Transition asset	-	-	-
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ (23.8)	$ (7.0)	$ 19.9
Total recognized in net periodic benefit cost, Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ (12.5)	$ 6.0	$ 27.5

Postretirement

$ in millions	Years ended December 31, 2013	2012	2011
Net actuarial loss / (gain)	$ (1.9)	$ 1.1	$ (1.3)
Prior service credit	-	-	-
Reversal of amortization item:			
Net actuarial gain	0.7	0.9	1.2
Prior service credit	(0.1)	(0.1)	(0.1)
Transition asset	-	-	-
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ (1.3)	$ 1.9	$ (0.2)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ (1.1)	$ 1.8	$ (0.4)

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2014 are:

$ in millions	Pension	Postretirement
Net actuarial gain / (loss)	$ 6.4	$ (0.8)
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 2014, we are decreasing our expected long-term rate of return assumption from 7.00% to 6.75% for pension plan assets and we are maintaining 6.00% for postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our current portfolio mixes. Also, for 2014, we have increased our assumed discount rate to 4.86% from 4.04% for pension and to 4.58% from 3.75% for postemployment 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 2014 pension expense of approximately $3.4 million. A 25 basis point change in the discount rate for pension would result in an increase or decrease of approximately $0.3 million to 2014 pension expense.

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, 2013, 2012 and 2011 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2013	2012	2011	**2013**	2012	2011
Discount rate for obligations	**4.86%**	4.04%	4.88%	**4.58%**	3.75%	4.62%
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, 2013, 2012 and 2011 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2013	2012	2011	**2013**	2012	2011
Discount rate	**4.04%**	4.88%	5.31%	**4.58%**	4.62%	4.96%
Expected rate of return on plan assets	**6.75%**	7.00%	8.00%	**6.00%**	6.00%	6.00%
Rate of compensation increases	**3.94%**	3.94%	3.94%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2013, 2012 and 2011 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2013	2012	2011	**2013**	2012	2011
Pre - age 65						
Current health care cost trend rate	**8.00%**	8.50%	8.50%	**7.75%**	8.00%	8.50%
Year trend reaches ultimate	**2019**	2019	2018	**2023**	2019	2019
Post - age 65						
Current health care cost trend rate	**7.50%**	8.00%	8.00%	**6.75%**	7.50%	8.00%
Year trend reaches ultimate	**2018**	2018	2017	**2021**	2018	2018
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 postemployment benefit cost and the accumulated postemployment 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	$ 0.9	$ (0.8)

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

Estimated future benefit payments and Medicare Part D reimbursements

$ in millions due within the following years:	Pension	Postretirement
2014	$ 25.0	$ 2.2
2015	$ 23.9	$ 2.1
2016	$ 23.9	$ 2.0
2017	$ 24.3	$ 1.8
2018	$ 24.6	$ 1.6
2019 - 2023	$ 126.5	$ 6.7

We expect to make contributions of $0.4 million to our SERP in 2014 to cover benefit payments. We also expect to contribute $1.9 million to our other postemployment benefit plans in 2014 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 2013 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 113.96% and is estimated to be 113.96% until the 2014 status is certified in September 2014 for the 2014 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 hedge funds that follow several different strategies.

The fair values of our pension plan assets at December 31, 2013 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2013

Asset Category $ in millions	Market Value at December 31, 2013	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	$ 10.5	$ 10.5	$ -	$ -
Large cap equity	20.8	20.8	-	-
International equity	20.3	20.3	-	-
Emerging markets equity	3.2	3.2	-	-
SIIT dynamic equity	10.5	10.5	-	-
Total equity securities	65.3	65.3	-	-
Debt Securities [(b)]				
Emerging markets debt	6.6	6.6	-	-
High yield bond	6.9	6.9	-	-
Long duration fund	223.3	223.3	-	-
Total debt securities	236.8	236.8	-	-
Cash and cash equivalents [(c)]				
Cash	0.9	0.9	-	-
Other investments [(d)]				
Core property collective fund	23.5	-	23.5	-
Common collective fund	22.6	-	22.6	-
Total other investments	46.1	-	46.1	-
Total pension plan assets	$ 349.1	$ 303.0	$ 46.1	$ -

(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. The fair value of cash equals its book value.

(d) This category represents a property fund that invests in commercial real estate 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 funds 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, 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	$ 324.4	$ 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 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 hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. 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.

This disclosure reflects changes in the 2012 presentation for $310.5 million of equity and debt mutual funds that were previously presented as Level 2 fair value measurements which have been reclassified as Level 1 fair value measurements. In addition, this disclosure reflects changes in the 2012 presentation for $37.0 million of alternative investment funds that were previously presented as Level 3 fair value measurements which have been reclassified as Level 2 fair value measurements. This change in presentation does not impact the fair value of the securities or the financial statements for the year ended December 31, 2012.

The fair values of our other postemployment benefit plan assets at December 31, 2013 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2013

Asset Category $ in millions	**Market Value at December 31, 2013**	**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)]	**$ 3.7**	**$ 3.7**	**$ -**	**$ -**

(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 postemployment 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.

This disclosure reflects changes in the 2012 presentation for $4.2 million of debt mutual funds that were previously presented as Level 2 fair value measurements which have been reclassified as Level 1 fair value measurements. This change in presentation does not impact the fair value of the securities or the financial statements for the year ended December 31, 2012.

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 in the year ended December 31, 2011.

Note 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, 2013 and 2012. See also Note 10 for the fair values of our derivative instruments.

	December 31, 2013		December 31, 2012	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
Assets				
Money market funds	$ 0.3	$ 0.3	$ 0.2	$ 0.2
Equity securities	3.3	4.4	4.0	5.1
Debt securities	5.4	5.5	4.6	5.0
Hedge Funds	0.9	0.9	-	-
Real Estate	0.4	0.4	0.3	0.3
Total assets	$ 10.3	$ 11.5	$ 9.1	$ 10.6
Liabilities				
Debt	$ 877.9	$ 859.6	$ 903.1	$ 926.9

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 $1.2 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2013 and $1.6 million ($1 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2012.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. During the past twelve months, $2.1 million ($1.4 million after tax) of unrealized gains were reversed into earnings. Over the next twelve months, $0.1 million ($0.1 million after tax) of unrealized gains are expected to be reversed to earnings.

Net Asset Value (NAV) per Unit
The following tables disclose the fair value and redemption frequency for those assets whose fair value is estimated using the NAV per unit as of December 31, 2013 and 2012. These assets are part of the Master Trust. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of December 31, 2013, **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, 2013	Unfunded Commitments	Redemption Frequency
Money market fund [(a)]	$ 0.3	$ -	Immediate
Equity securities [(b)]	4.4	-	Immediate
Debt Securities [(c)]	5.5	-	Immediate
Hedge Funds [(d)]	0.9	-	Quarterly
Real Estate [(e)]	0.4	-	Quarterly
Total	$ 11.5	$ -	

(a) This category includes investments in high-quality, short-term securities. Investments in this category can be redeemed immediately at the current NAV.
(b) This category includes investments in hedge funds representing an S&P 500 Index and the Morgan Stanley Capital International U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current NAV 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 NAV per unit.
(d) This category includes hedge funds investing in fixed income securities and currencies, short and long-term equity investments, and a diversified fund with investments in bonds, stocks, real estate and commodities.
(e) This category includes EFT real estate funds that invest in U.S. and International properties.

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	Fair Value at December 31, 2012	Unfunded Commitments	Redemption 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	$ -	

(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);
- 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, 2013 and 2012.

The fair value of assets and liabilities at December 31, 2013 and 2012 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, 2013 (a)	Based on Quoted Prices in Active Markets	Other observable inputs	Unobservable inputs
Assets				
Master trust assets				
Money market funds	$ 0.3	$ 0.3	$ -	$ -
Equity securities	4.4	-	4.4	-
Debt securities	5.5	-	5.5	-
Hedge Funds	0.9	-	0.9	-
Real Estate	0.4	-	0.4	-
Total Master trust assets	11.5	0.3	11.2	-
Derivative assets				
Heating oil futures	0.2	0.2	-	-
FTRs	0.2	-	-	0.2
Forward power contracts	13.4	-	13.4	-
Total derivative assets	13.8	0.2	13.4	0.2
Total assets	$ 25.3	$ 0.5	$ 24.6	$ 0.2
Liabilities				
Derivative liabilities				
Forward power contracts	10.6	-	10.6	-
Total derivative liabilities	10.6	-	10.6	-
Long-Term Debt	859.6	-	841.1	18.5
Total liabilities	$ 870.2	$ -	$ 851.7	$ 18.5

(a) Includes credit valuation adjustment.

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 Unobservable 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				
Forward NYMEX coal contracts	$ 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.

Our financial instruments are valued using the market approach in the following categories:

- 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.
- Level 3 inputs such as financial transmission rights are considered a Level 3 input 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 95% 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. An 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 no additions to our AROs during the year ended December 31, 2013.

When evaluating impairment of goodwill and long-lived assets, we measure fair value using the applicable fair value measurement guidance. Impairment expense is measured by comparing the fair value at the evaluation date to the carrying amount. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy:

$ in millions	**Year ended December 31, 2013**				
	Carrying Amount	**Fair Value Level 1**	**Fair Value Level 2**	**Fair Value Level 3**	**Gross Loss**
Assets					
Long-lived assets held and used [(a)]					
Conesville	**$ 30.0**	**$ -**	**$ -**	**$ 20.0**	**$ 10.0**
East Bend	**$ 76.0**	**$ -**	**$ -**	**$ -**	**$ 76.0**

$ in millions	Year ended December 31, 2012				
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Gross Loss
Assets					
Long-lived assets held and used [(a)]					
Conesville	$ 97.5	$ -	$ -	$ 25.0	$ 72.5
Hutchings	$ 8.3	$ -	$ -	$ -	$ 8.3

(a) See Note 15 for further information.

The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived assets during the year ended December 31, 2013:

$ in millions	Fair Value	Valuation Technique	Unobservable input	Range (Weighted Average)
Long-lived assets held and used:				
Conesville	$ 20.0	Discounted cash flows	Annual revenue growth	-31% to 18% (0%)
			Annual pretax operating margin	-9% to 18% (10%)
East Bend	$ -	Discounted cash flows	Annual revenue growth	-15% to 22% (4%)
			Annual pretax operating margin	-3% to 34% (15%)

Note 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, 2013, **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	-	7.1
Heating Oil Futures	Mark to Market	Gallons	1,428.0	-	1,428.0
Forward Power Contracts	Cash Flow Hedge	MWh	140.4	(4,705.7)	(4,565.3)
Forward Power Contracts	Mark to Market	MWh	3,172.4	(2,888.5)	283.9

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	-	1,764.0
Forward Power Contracts	Cash Flow Hedge	MWh	1,021.0	(2,197.9)	(1,176.9)
Forward Power Contracts	Mark to Market	MWh	2,296.6	(4,760.4)	(2,463.8)

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:

$ in millions (net of tax)	**Year ended December 31, 2013**		Year ended December 31, 2012		Year ended December 31, 2011	
	Power	**Interest Rate Hedge**	Power	Interest Rate Hedge	Power	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI [a]	$ (4.7)	$ 7.3	$ (0.8)	$ 9.8	$ (1.8)	$ 12.2
Net gains / (losses) associated with current period hedging transactions	1.0	-	(3.0)	-	(1.2)	-
Net gains reclassified to earnings:						
Interest Expense	-	(2.1)	-	(2.5)	-	(2.4)
Revenues	1.4	-	(1.1)	-	1.2	-
Purchased Power	3.3	-	0.2	-	1.0	-
Ending accumulated derivative gain / (loss) in AOCI	$ 1.0	$ 5.2	$ (4.7)	$ 7.3	$ (0.8)	$ 9.8

Net gains or losses associated with the ineffective portion of the hedging transactions were immaterial in the years ended December 31, 2013, 2012 and 2011.

Portion expected to be reclassified to earnings in the next twelve months [a]	$ (2.2)	$ (1.1)				
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	36	0				

(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.

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 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, 2013, 2012 and 2011.

Year ended December 31, 2013

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ -	$ -	$ 0.3	$ (1.2)	$ (0.9)
Realized gain	-	0.1	1.2	1.6	2.9
Total	$ -	$ 0.1	$ 1.5	$ 0.4	$ 2.0
Recorded on Balance Sheet:					
Partners' share of loss	$ -	$ -	$ -	$ -	$ -
Regulatory asset	-	-	-	-	-
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	0.2	0.2
Purchased Power	-	-	1.5	0.2	1.7
Fuel	-	0.1	-	-	0.1
O&M	-	-	-	-	-
Total	$ -	$ 0.1	$ 1.5	$ 0.4	$ 2.0

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)

The following tables show the fair value and balance sheet classification of **DP&L's** derivative instruments at December 31, 2013 and 2012.

Fair Values of Derivative Instruments
December 31, 2013

			Gross Amounts Not Offset in the Balance Sheets		
$ in millions	Hedging Designation	Gross Fair Value as presented in the Balance Sheets	Financial Instruments with Same Counterparty in Offsetting Position	Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Cash Flow	$ 0.5	$ (0.2)	$ -	$ 0.3
Forward power contracts	MTM	4.9	(4.2)	-	0.7
FTRs	MTM	0.2	-	-	0.2
Heating oil futures	MTM	0.2	-	(0.2)	-
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Cash Flow	3.0	-	(3.0)	-
Forward power contracts	MTM	5.0	(0.3)	-	4.7
Total assets		$ 13.8	$ (4.7)	$ (3.2)	$ 5.9
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Cash Flow	$ 2.7	$ (0.2)	$ (2.3)	$ 0.2
Forward power contracts	MTM	6.6	(4.2)	(2.3)	0.1
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	MTM	1.3	(0.3)	(1.0)	-
Total liabilities		$ 10.6	$ (4.7)	$ (5.6)	$ 0.3

Fair Values of Derivative Instruments
December 31, 2012

$ in millions	Hedging Designation	Gross Fair Value as presented in the Balance Sheets	Gross Amounts Not Offset in the Balance Sheets: Financial Instruments with Same Counterparty in Offsetting Position	Gross Amounts Not Offset in the Balance Sheets: Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Cash Flow	$ 0.5	$ (0.5)	$ -	$ -
Forward power contracts	MTM	2.8	(1.5)	-	1.3
Heating oil futures	MTM	0.2	-	(0.2)	-
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Cash Flow	0.5	(0.5)	-	-
Forward power contracts	MTM	3.6	(0.6)	-	3.0
Total assets		$ 7.6	$ (3.1)	$ (0.2)	$ 4.3
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Cash Flow	$ 6.7	$ (0.5)	$ (2.1)	$ 4.1
FTRs	MTM	0.1	-	-	0.1
Forward power contracts	MTM	2.7	(1.5)	(0.5)	0.7
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Cash Flow	1.5	(0.5)	(0.9)	0.1
Forward power contracts	MTM	0.7	(0.6)	-	0.1
Total liabilities		$ 11.7	$ (3.1)	$ (3.5)	$ 5.1

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, we are 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. 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, 2013 is $10.6 million. This amount is offset by $5.6 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 $4.7 million. If **DP&L** debt were to fall below investment grade, **DP&L** could be required to post collateral for the remaining $0.3 million.

Note 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, discussed in 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):

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

(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):

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

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):

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

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):

	Year ended December 31, 2011
Performance shares:	
Outstanding at beginning of period	278,334
Granted	85,093
Dividends	(198,699)
Exercised	(66,836)
Forfeited	(97,892)
Outstanding at end of period	-
Exercisable at end of period	-

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):

$ in millions		Year ended December 31, 2011
Weighted-average grant date fair value of performance shares granted during the period	$	2.2
Intrinsic value of performance shares exercised during the period	$	6.0
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
Unrecognized compensation expense	$	-
Weighted-average period to recognize compensation expense (in years)		-

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:

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

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):

	Year ended December 31, 2011
Restricted shares:	
Outstanding at beginning of period	219,391
Granted	67,346
Exercised	(286,737)
Forfeited	-
Outstanding at end of period	-
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):

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

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):

	Year ended December 31, 2011
Restricted stock units:	
Outstanding at beginning of period	16,320
Granted	14,392
Dividends accrued	3,307
Vested and exercised	(34,019)
Vested, exercised and deferred	-
Forfeited	-
Outstanding at end of period	-
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	Year ended December 31, 2011
Weighted-average grant date fair value of non-employee Director RSUs granted during the period	$ 0.5
Intrinsic value of non-employee Director RSUs exercised during the period	$ 1.0
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
Unrecognized compensation expense	$ -
Weighted-average period to recognize compensation expense (in years)	-

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):

	Year ended December 31, 2011
Management performance shares:	
Outstanding at beginning of period	104,124
Granted	49,510
Expired	(31,081)
Exercised	(111,289)
Forfeited	(11,264)
Outstanding at end of period	-
Exercisable at end of period	-

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:

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

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):

$ in millions		Year ended December 31, 2011
Weighted-average grant date fair value of management performance shares granted during the period	$	1.3
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
Unrecognized compensation expense	$	-
Weighted-average period to recognize compensation expense (in years)		-

Note 12 – Redeemable Preferred Stock

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding as of December 31, 2013. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2013. The table below details the preferred shares outstanding at December 31, 2013 and 2012:

$ in millions except per share amounts	Preferred Stock Rate	December 31, 2013 and 2012 Redemption price ($ per share)	 Shares Outstanding	Par Value ($ in millions) December 31, 2013	 December 31, 2012
DP&L Series A	3.75%	$ 102.50	93,280	$ 9.3	$ 9.3
DP&L Series B	3.75%	$ 103.00	69,398	7.0	7.0
DP&L Series C	3.90%	$ 101.00	65,830	6.6	6.6
Total			228,508	$ 22.9	$ 22.9

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

As long as any **DP&L** preferred stock is outstanding, **DP&L's** Amended Articles of Incorporation also contain provisions restricting the payment of cash dividends on any of its common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds the net income of **DP&L** available for dividends on its common stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not impacted **DP&L's** ability to pay cash dividends and, as of December 31, 2013, **DP&L's** retained earnings of $426.8 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.

Note 13 – Common Shareholders' Equity

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 2013. 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.

Note 14 – Contractual Obligations, Commercial Commitments and Contingencies

DP&L – Equity Ownership Interest

DP&L has 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, 2013, **DP&L** could be responsible for the repayment of 4.9%, or $76.4 million, of a $1,558.4 million debt obligation comprised of both fixed and variable rate securities with maturities between 2014 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2013, 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, 2013, 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	$ 877.8	$ 0.2	$ 445.2	$ 0.2	$ 432.2
Interest payments	361.0	24.1	48.4	31.7	256.8
Pension and postretirement payments	264.5	27.2	51.9	52.3	133.1
Operating leases	0.6	0.4	0.2	-	-
Coal contracts [(a)]	625.6	216.5	270.3	138.8	-
Limestone contracts [(a)]	24.4	6.1	12.2	6.1	-
Purchase orders and other contractual obligations	85.6	48.8	18.7	18.1	-
Total contractual obligations	$ 2,239.5	$ 323.3	$ 846.9	$ 247.2	$ 822.1

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

Long-term debt:

DP&L's long-term debt as of December 31, 2013, 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, 2013.

Pension and postemployment payments:

As of December 31, 2013, **DP&L** had estimated future benefit payments as outlined in Note 8. These estimated future benefit payments are projected through 2023.

Capital leases:

As of December 31, 2013, **DP&L** had one immaterial capital lease that expires in 2014.

Operating leases:

As of December 31, 2013, **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, 2013, **DP&L** had various other contractual obligations including non-cancelable contracts to purchase goods and services with various terms and expiration dates.

Reserve for uncertain tax positions:

Due to the uncertainty regarding the timing of future cash outflows associated with our unrecognized tax benefits of $8.8 million at December 31, 2013, we are unable to make a reliable estimate of the periods of cash settlement with the respective tax authorities and have not included such amounts in the contractual obligations table above.

Contingencies
In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our 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, 2013, 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. The environmental issues that may affect us include:

- The federal CAA and state laws and regulations (including State Implementation Plans) which require compliance, obtaining permits and reporting as to air emissions,
- Litigation with federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating stations require additional permitting or pollution control technology, or whether emissions from coal-fired generating stations cause or contribute to global climate changes,
- Rules and future rules issued by the USEPA and the Ohio EPA that require substantial reductions in SO_2, particulates, mercury, acid gases, NO_x, and other air emissions. **DP&L** has installed emission control technology and is taking other measures to comply with required and anticipated reductions,
- Rules and future rules issued by the USEPA and the Ohio EPA that require reporting and may require reductions of GHGs,
- *Rules and future rules issued by the USEPA associated with the federal Clean Water Act, which prohibits* the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and
- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain waste. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion by-products. The USEPA has previously determined that fly ash and other coal combustion by-products are not hazardous waste subject to the Resource Conservation and Recovery Act (RCRA), but the USEPA is reconsidering that determination and planning to propose a new rule regulating coal combustion by-products. A change in determination or other additional regulation of fly ash or other coal combustion byproducts could significantly increase the costs of disposing of such by-products.

In addition to 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 our facilities to comply, or to determine compliance, with such regulations. We record liabilities for loss contingencies related to environmental matters when a loss is probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. Accordingly, we have accruals for loss contingencies of approximately $1.1 million for environmental matters. We also have a number of environmental matters for which we have not accrued loss contingencies because the risk of loss is not probable of a loss cannot be reasonably estimated, which are disclosed in the paragraphs below. We evaluate the potential liability related to 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 coal-fired generation units. Some of these matters could have material adverse impacts on the operation of the power stations; especially the stations that do not have SCR and FGD equipment installed to further control certain emissions. Currently, the coal-fired generation unit Beckjord Unit 6, in which **DP&L** has a 50% ownership interest, does not have such emission-control equipment installed. This unit is scheduled to be deactivated on June 1, 2015. **DPL** valued Beckjord Unit 6 at zero at the Merger date. **DP&L** is depreciating Unit 6 through December 2014 and does not believe that any additional accruals or impairment charges are needed as a result of this decision.

DP&L deactivated the coal units at Hutchings Station in September 2013 as part of a settlement with the USEPA discussed in more detail below.

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.

Clean Air Interstate Rule/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 NO_x emissions from existing power stations located in 27 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase began in 2009 and 2010 for NO_x and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions is scheduled 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 the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, CSAPR would have required significant reductions in SO_2 and NO_x emissions from covered sources, such as power stations in 28 eastern states. Once fully implemented in 2014, the rule would have required additional SO_2 emission reductions of 73% and additional NO_x 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. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that the 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 are to continue to serve as the governing program until the USEPA takes further action or the U.S. Congress intervenes. On October 5, 2012, the 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, which were denied. On June 24, 2013, the U.S. Supreme Court agreed to review the D.C. Circuit Court's decision to vacate CSAPR and heard oral arguments in the matter on December 10, 2013. Currently, 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 unit 6 will not operate on coal in 2015 due to implementation of the Mercury and Air Toxics Standards (MATS). If the USEPA issues 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.

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, on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Our affected EGUs must come into compliance with the new requirements by April 16, 2015, but may be granted an additional year to become compliant 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 January 31, 2013, the USEPA finalized a rule regulating emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers and process heaters at major and area source facilities. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulation contains emissions limitations, operating limitations and other requirements. **DP&L** expects to be in compliance with this rule and the costs are not currently expected to be material to **DP&L's** operations.

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, the USEPA redesignated Adams County, where Stuart and Killen are located, to attainment status. 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, including in counties where we have generating stations. 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.

The USEPA published the national ground level ozone standard on March 12, 2008, lowering the 8-hour level from 0.08 ppm to 0.075 ppm, which was upheld by the U.S. Circuit Court of Appeals in July 2013. No **DP&L** operations are currently located in non-attainment areas. The USEPA was expected to review the ozone NAAQS in 2013 but delayed such a review. Certain environmental groups have sued the USEPA in federal district court to force the USEPA to set a September 30, 2014 deadline for such review. It is generally expected that any revised standard resulting from such review would be more stringent than the current 0.075 ppm standard. In addition, in December 2013, eight northeastern states petitioned the USEPA to add nine upwind states, including Ohio, to the Ozone Transport Region, a group of states required to impose enhanced restrictions on ozone emissions. If the petition is granted, our facilities could be subject to such enhanced requirements.

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. Initial non-attainment designations were made July 25, 2013. Non-attainment areas will be required to meet the new standard by October 2018.

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 GHG 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, the 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, the USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under the USEPA's view, this is the final action that renders CO_2 and certain 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. Various industry groups and states petitioned the U.S. Supreme Court to review the D.C. Circuit Court's recent decision to uphold the USEPA's endangerment finding, its April 2010 GHG rule and the Tailoring Rule. On October 15, 2013, the U.S. Supreme Court agreed to review several related cases addressing the USEPA's authority to issue GHG Prevention of Significant Deterioration permits under Section 165 of the CAA. We cannot predict the outcome of this review. 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 September 20, 2013, the USEPA proposed revised GHG New Source Performance Standards for new electric generating units (EGUs) under CAA subsection 111(b), which would require new EGUs to limit the amount of CO_2 emitted per megawatt-hour. The proposal anticipates that affected coal-fired units would need to rely upon partial implementation of carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. Furthermore, President Obama directed the USEPA to propose new standards, regulations, or guidelines, as appropriate, to address GHG emissions from existing EGUs under CAA subsection 111(d) by June 1, 2014, and finalize them by June 1, 2015. These latter rules may focus on energy efficiency improvements at power stations. We cannot predict the effect of these proposed or forthcoming standards on **DP&L's** operations.

Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 14 million tons annually. Further GHG legislation or regulation implemented 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 effect 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 NO_x, 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 AEP Generation (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. The Conesville complaint was resolved in 2007 as part of a larger settlement with the USEPA. Conesville was required to install FGD and SCR at the unit by the end of 2010, and those retrofits have been completed. The Beckjord complaint was also resolved through litigation. There were no penalties or settlement agreements that affected Beckjord 6.

In June 2000, the USEPA issued an NOV to the **DP&L**-operated Stuart generating station (co-owned by **DP&L**, Duke Energy and AEP Generation) 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, the 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. 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. As a result of the cessation of operations at the Hutchings Station discussed in the next paragraph, **DP&L** believes that the USEPA is unlikely to pursue the NSR complaint.

As part of a settlement with the USEPA, **DP&L** signed a Consent Agreement and Final Order (CAFO) that was filed on September 26, 2013 and an Administrative Consent Agreement. Together, these two agreements resolved the opacity and particulate emissions NOV at the Hutchings Station and required that all six coal-fired units at Hutchings cease operating on coal by September 30, 2013, and included an immaterial penalty and the completion of a Supplemental Environmental Project of $0.2 million within one year. The units were disabled for coal operations prior to September 30, 2013.

DP&L also resolved all issues associated with the Ohio EPA NOV through a settlement signed October 4, 2013. The settlement included the payment of an immaterial penalty.

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. The USEPA is required pursuant to a settlement agreement to issue a final rule by April 17, 2014. We do not yet know the impact the final rules will have on our operations.

Clean Water Act – Regulation of Water Discharge
In December 2006, **DP&L** submitted a renewal application for the Stuart Station NPDES permit that was due to expire on June 30, 2007. The Ohio EPA issued a revised draft permit that was received on November 12, 2008. In September 2010, the USEPA formally objected to the November 12, 2008 revised permit due to questions regarding the basis for the alternate thermal limitation. At **DP&L's** request, a public hearing was held on March 23, 2011, where **DP&L** presented its position on the issue and provided written comments. 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 did not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit would 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 required **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, the 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, the 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 appeal process, the effects could be material on **DP&L's** operations.

In September 2009, the USEPA announced that it would 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. The proposed rule was released on June 7, 2013, with a deadline for a final rule on May 22, 2014, though such final rule's issuance is expected to be delayed. 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 January 2014, **DP&L** submitted an application for the renewal of the Hutchings Station NPDES permit which expires in July 2014. 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** installed sedimentation ponds as part of the runoff control measures to address this issue and worked with the various agencies to resolve their concerns. **DP&L** signed an Administrative Order from the USEPA on May 30, 2013. A final Consent Agreement and Final Order was executed on July 8, 2013, and the previously issued permit was reinstated by the Corps on October 29, 2013.

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. 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 the PRP group in performing an RI/FS. That summary judgment ruling was appealed on March 4, 2013 and the appeal is pending. **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.

Beginning in mid-2012, the USEPA began investigating whether explosive or other dangerous conditions exist under structures located at or near the South Dayton Dump landfill site. In October 2012, **DP&L** received a request from the PRP group's consultant to conduct additional soil and groundwater sampling on **DP&L's** service center property. After informal discussions with the USEPA, **DP&L** complied with this sampling request and the sampling was conducted in February 2013. On February 28, 2013, the plaintiffs group referenced above entered into an Administrative Settlement Agreement Consent Order (ASACO) that establishes procedures for further sub-slab testing under structures at the South Dayton Dump landfill site and remediation of vapor intrusion issues relating to trichloroethylene (TCE), percholorethylene (PCE), and methane. On April 16, 2013, the plaintiffs group filed a new complaint in the United States District Court for the Southern District of Ohio against **DP&L** and 34 other defendants alleging that they share liability for these costs. **DP&L** has opposed the allegations that it bears any responsibility under the February 2013 ASACO and will actively oppose any attempt that the plaintiffs group may have to expand the scope of the new complaint to resurrect issues dismissed by the Court in February 2013 under the first complaint. A motion to dismiss portions of this second complaint relating to alleged migration of chemicals from **DP&L** property to the landfill was denied February 18, 2014, as were motions filed by DP&L and others to dismiss other portions of the complaint that were viewed by defendants as identical to the allegations dismissed in the first complaint proceeding. The Judge found that there were differences in the allegations and is permitting those allegations to proceed.. Limited discovery has been permitted pending resolution of the motion including some depositions of former **DP&L** employees during 2013 and into 2014. DP&L cannot predict the outcome of this proceeding.

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 previously indicated that the official release date for a proposed rule was in April 2013, it has been delayed, likely until late 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. On March 14, 2013, **DP&L** received the final report on the inspection of the Killen Station ash pond inspection from the USEPA which included recommended actions. **DP&L** has submitted a response with its actions to the USEPA. **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 the USEPA has opposed. On January 29, 2014, the parties to the litigation entered into a consent decree setting forth the USEPA's obligation to sign, by December 19, 2014, a notice for publication in the Federal Register taking action on the Agency's proposed Subtitle D option. The decree does not require Subtitle D regulation of coal combustion byproducts – it only requires the Agency to decide by that date whether or not to adopt the Subtitle D option. 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 NPDES permit program and the station's storm water pollution prevention plan. The notice requested that **DP&L** respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on **DP&L's** results of operations, financial condition or cash flows.

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.

Note 15 – Fixed-asset Impairment

During the fourth quarter of 2013, the Company tested the recoverability of long-lived assets at Conesville, a 129 MW coal-fired station in Ohio, and East Bend, a 186 MW coal-fired station in Kentucky jointly-owned by **DP&L**. Gradual decreases in power prices, as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit of **DPL** failing step 1 of the annual goodwill impairment test were collectively determined to be an impairment indicator for the **DP&L** long-lived assets. The Company performed a long-lived asset impairment test and determined that the carrying amounts of the asset groups were not recoverable. 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. The Conesville and East Bend asset groups were each determined to have a zero fair value using discounted cash flows under the income approach. As a result, the Company recognized an asset impairment expense of $10.0 million and $76.0 million for Conesville and East Bend, respectively.

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.

Note 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

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, 2013 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, 2013.

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). Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations ("COSO") in 1992. Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2013.

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 for 2013 and 2012. Other than as set forth below, no professional services were rendered or fees billed by Ernst & Young LLP during 2013 and 2012.

	2013 fees billed	2012 fees billed
Audit fees (a)	$ 1,368,500	$ 1,826,450
Audit-related Fees (b)	461,000	391,000
Tax Fees (c)	-	-
All Other Fees	14,600	-
Total	$ 1,844,100	$ 2,217,450

(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 and services rendered under an agreed upon procedure engagement related to environmental studies..
(b) Audit-related fees relate to services rendered to us for assurance and related services.
(c) Tax fees consisted principally of tax compliance services.

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-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

2. Financial Statement Schedules

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

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	Exhibit 3(a) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-2385)
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 ended December 31, 1985 (File No. 1-2385)
X	X	4(b)	Forty-First Supplemental Indenture dated as of February 1, 1999, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4(m) to Report on Form 10-K for the year ended December 31, 1998 (File No. 1-2385)
X	X	4(c)	Forty-Second Supplemental Indenture dated as of September 1, 2003, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4(r) to Report on Form 10-K for the year ended December 31, 2003 (File No. 1-9052)
X	X	4(d)	Forty-Third Supplemental Indenture dated as of August 1, 2005, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4.4 to Report on Form 8-K filed August 24, 2005 (File No. 1-2385)
X		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 ended 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 ended 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 Corporation (File No. 1-12291)
X		4(k)	Supplemental Indenture, dated as of November 28, 2011, between DPL Inc. and Wells Fargo Bank, National Association	Exhibit 4(k) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-2385)
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	Exhibit 4(l) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-2385)
	X	4(m)	Registration Rights Agreement, dated as of September 19, 2013, by and between Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the initial purchasers	Exhibit 4.1 to Report on Form 8-K filed September 25, 2013 (File No. 1-2385)
	X	4(n)	47th Supplemental Indenture to the First and Refunding Mortgage, dated as of September 1, 2013, by and between the Bank of New York Mellon, as Trustee, and The Dayton Power and Light Company	Exhibit 4.2 to Report on Form 8-K filed September 25, 2013 (File No. 1-2385)
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, and the lenders party to the Credit Agreement	Exhibit 10.1 to Form 8-K filed April 22, 2010 (File No. 1-2385)

DPL	DP&L	Exhibit Number	Exhibit	Location
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	Exhibit 10(c) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-2385)
X	X	10(d)	Credit Agreement, dated as of August 24, 2011, among DPL Inc., PNC Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, 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(d) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-2385)
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(e) 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, 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. 1-2385)
X		10(g)	Credit Agreement, dated as of May 10, 2013, among DPL Inc., PNC Bank, National Association, as Administrative Agent, Fifth Third Bank and U.S. Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the other lenders party to the Credit Agreement	Exhibit 10.1 to Report on Form 8-K filed May 16, 2013 (File No. 1-2385)

DPL	DP&L	Exhibit Number	Exhibit	Location
X		10(h)	Credit Agreement, dated as of May 10, 2013, among DPL Inc., U.S. Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, Fifth Third Bank and PNC Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the other lenders party to the Credit Agreement	Exhibit 10.2 to Report on Form 8-K filed May 16, 2013 (File No. 1-2385)
X		10(i)	Credit Agreement, dated as of May 10, 2013, among The Dayton Power and Light Company, Fifth Third Bank, as Administrative Agent, Swing Line Lender and an L/C Issuer, U.S. Bank, National Association and PNC Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the other lenders party to the Credit Agreement	Exhibit 10.3 to Report on Form 8-K filed May 16, 2013 (File No. 1-2385)
X		31(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(a)
X		31(b)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(b)
	X	31(c)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(c)
	X	31(d)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(d)
X		32(a)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(a)
X		32(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(b)
	X	32(c)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(c)
	X	32(d)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(d)

DPL	DP&L	Exhibit Number	Exhibit	Location
X	X	101.INS	XBRL Instance	Furnished herewith as Exhibit 101.INS
X	X	101.SCH	XBRL Taxonomy Extension Schema	Furnished herewith as Exhibit 101.SCH
X	X	101.CAL	XBRL Taxonomy Extension Calculation Linkbase	Furnished herewith as Exhibit 101.CAL
X	X	101.DEF	XBRL Taxonomy Extension Definition Linkbase	Furnished herewith as Exhibit 101.DEF
X	X	101.LAB	XBRL Taxonomy Extension Label Linkbase	Furnished herewith as Exhibit 101.LAB
X	X	101.PRE	XBRL Taxonomy Extension Presentation Linkbase	Furnished herewith as Exhibit 101.PRE

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

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, we have not filed as an exhibit to this Form 10-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.

March 4, 2014 By: /s/ Kenneth J. Zagzebski
(Kenneth J. Zagzebski)
President and Chief Executive Officer
(principal executive officer)

The Dayton Power and Light Company

March 4, 2014 By: /s/ Derek A. Porter
(Derek A. Porter)
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	March 4, 2014
/s/ Philip R. Herrington (Philip R. Herrington)	Director	March 4, 2014
/s/ Willard C. Hoagland, III (Willard C. Hoagland, III)	Director	March 4, 2014
/s/ Brian A. Miller (Brian A. Miller)	Director	March 4, 2014
/s/ Thomas M. O'Flynn (Thomas M. O'Flynn)	Director	March 4, 2014
(Mary Stawikey)	Director	March 4, 2014
(Andrew M. Vesey)	Director and Chairman	March 4, 2014
/s/ Craig L. Jackson (Craig L. Jackson)	Chief Financial Officer (principal financial officer)	March 4, 2014
/s/ Kurt A. Tornquist (Kurt A. Tornquist)	Controller (principal accounting officer)	March 4, 2014
/s/ Kenneth J. Zagzebski (Kenneth J. Zagzebski)	President and Chief Executive Officer (principal executive officer)	March 4, 2014

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	March 4, 2014
/s/ Elizabeth Hackenson (Elizabeth Hackenson)	Director	March 4, 2014
/s/ Derek A. Porter (Derek A. Porter)	Director, President and Chief Executive Officer (principal executive officer)	March 4, 2014
/s/ Vincent W. Mathis (Vincent W. Mathis)	Director	March 4, 2014
/s/ Brian A. Miller (Brian A. Miller)	Director	March 4, 2014
/s/ Britaldo Pedrosa Soares (Britaldo Pedrosa Soares)	Director	March 4, 2014
(Andrew M. Vesey)	Director and Chairman	March 4, 2014
/s/ Thomas M. O'Flynn (Thomas M. O'Flynn)	Director	March 4, 2014
/s/ Kenneth J. Zagzebski (Kenneth J. Zagzebski)	Director	March 4, 2014
/s/ Craig L. Jackson (Craig L. Jackson)	Chief Financial Officer (principal financial officer)	March 4, 2014
/s/ Kurt A. Tornquist (Kurt A. Tornquist)	Controller (principal accounting officer)	March 4, 2014

Schedule II

DPL Inc.
VALUATION AND QUALIFYING ACCOUNTS
For the years ended Year ended December 31, 2011 - 2013

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions [a]	Balance at End of Period
Successor				
Year ended December 31, 2013				
Deducted from accounts receivable -				
Provision for uncollectible accounts	$ 1,084	$ 6,156	$ 6,080	$ 1,160
Deducted from deferred tax assets -				
Valuation allowance for deferred tax assets	$ 12,349	$ 2,159	$ 787	$ 13,721
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
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				
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

[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, 2011 - 2013

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions [a]	Balance at End of Period
Year ended December 31, 2013				
Deducted from accounts receivable -				
Provision for uncollectible accounts	$ 923	$ 4,924	$ 4,938	$ 909
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

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