BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 20-1651-EL-AIR
CASE NO. 20-1652-EL-AAM
CASE NO. 20-1653-EL-ATA

2020 DISTRIBUTION BASE RATE CASE

BOOK I – APPLICATION AND SUPPLEMENTAL
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Dayton Power and Light Company

DP&L Case No. 20-1651-EL-AIR

Standard Filing Requirements for Rate Increases

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THE DAYTON POWER & LIGHT COMPANY

Case No. 20-1651-EL-AIR

Supplemental Information (C)(3)

Requirement:

Provide annual reports to shareholders of the applicant, and/or parent company, if applicant is wholly-owned subsidiary, for the most recent five years and the most recent statistical supplement.

Response:

See attached DP&L's 10K filings (2015-2019).

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, 2015**

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**

Securities registered pursuant to Section 12(g) 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 ☒

The Dayton Power and Light Company is a voluntary filer that has filed all applicable reports under Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months. During 2015, DPL Inc. was a voluntary filer until its May 29, 2015 Registration Statement on Form S-4 filed with the Securities and Exchange Commission was declared effective on June 12, 2015. DPL Inc. has 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.

At December 31, 2015, 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

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Annual Report on Form 10-K
Fiscal Year Ended December 31, 2015

GLOSSARY OF TERMS

The following select terms, 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 AEP Generation, effective January 1, 2014.
AER	Alternative Energy Rider which allows DP&L to recover costs related to meeting the Ohio renewable portfolio standards.
AES	The AES Corporation, a global power company, the ultimate parent company of DPL
AES Ohio Generation	AES Ohio Generation, LLC (formerly DPLE), a wholly-owned subsidiary of DPL that owns and operates peaking generation facilities from which it makes wholesale sales
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CFTC	Commodity Futures Trading Commission
CAA	U.S. Clean Air Act
CAIR	Clean Air Interstate Rule
Capacity Market	The purpose of the capacity market is to enable PJM to obtain sufficient resources to reliably meet the needs of electric customers within the PJM footprint. PJM procures capacity, through a multi-auction structure, on behalf of the load serving entities to satisfy the load obligations. There are four 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.
CCEM	Customer Conservation and Energy Management
CO_2	Carbon Dioxide
ComEd	Commonwealth Edison
CP	In 2015, PJM adopted changes to the capacity market known as "Capacity Performance". The CP program offers the potential for higher capacity revenues, combined with substantially increased penalties for non-performance or under-performance during certain periods identified as "capacity performance hours." The DP&L units will operate under the CP construct starting June 1, 2016.
CRES	Competitive Retail Electric Service
CSAPR	Cross-State Air Pollution Rule
CWA	U.S. Clean Water Act
Dark spread	A common metric used to estimate returns over fuel costs of coal-fired electric generating units
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
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 (renamed AES Ohio Generation, LLC effective February 1, 2016)
DPLER	DPL Energy Resources, Inc., formerly a wholly-owned subsidiary of DPL which sold competitive electric energy and other energy services, including sales by a wholly-owned subsidiary, MC Squared, which DPLER sold on April 1, 2015. DPLER was sold by DPL on January 1, 2016. The DPLER sale agreement was signed on December 28, 2015.

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
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 and transmission lines in Ohio (Duke Energy Ohio, Inc.)
Dynegy	Dynegy, Inc., the parent of various subsidiaries that, along with AEP Generation and DP&L, co-owns electric generating units in Ohio
EBITDA	Earnings before interest, taxes, depreciation and amortization
EGU	Electric generating unit
ERISA	The Employee Retirement Income Security Act of 1974
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
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
kV	Kilovolts, 1,000 volts
kWh	Kilowatt hour
LIBOR	London Inter-Bank Offering Rate
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
MATS	Mercury and Air Toxics Standards
MC Squared	MC Squared Energy Services, LLC, a retail electricity supplier formerly wholly-owned by DPLER, sold on April 1, 2015
Merger	The merger of DPL and Dolphin Sub, Inc. (a wholly-owned subsidiary of AES) in accordance with the terms of an Agreement and Plan of Merger dated April 19, 2011 among DPL, AES and Dolphin Sub, Inc. a wholly-owned subsidiary of AES. On the Merger date, 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.
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
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
Non-bypassable	Charges that are assessed to all customers regardless of whom the customer selects as their retail electric generation supplier
NOV	Notice of Violation
NO_X	Nitrogen Oxide

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
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
OCI	Other Comprehensive Income
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
PPM	Parts per million
PRP	Potentially Responsible Party
Predecessor	DPL prior to the Merger date
PUCO	Public Utilities Commission of Ohio
ROE	Return on equity
RPM	The Reliability Pricing Model was PJM's capacity construct.
RTO	Regional Transmission Organization
SB 221	Ohio Senate Bill 221, is 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.
SB 310	Ohio Senate Bill 310, an Ohio electric energy bill that was passed in May 2014 that required all Ohio utilities to show on each bill the approximate cost of complying with renewable energy, energy efficiency and peak demand requirements. It froze the Ohio renewable and energy efficiency annual targets for two year and required a legislative committee to evaluate whether or not the targets should continue.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SEET	Significantly Excessive Earnings Test
Service Company	AES US Services, LLC, the shared services affiliate providing accounting, finance, and other support services to AES' U.S. SBU businesses
SFAS	Statement of Financial Accounting Standards
SIP	A State Implementation Plan is a plan for complying with the federal CAA, administered by the USEPA. The SIP consists of narrative, rules, technical documentation and agreements that an individual state will use to clean up polluted areas.
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
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

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
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
U.S. SBU	U. S. Strategic Business Unit, AES' reporting unit covering the businesses in the United States, including DPL

PART I

This report includes the combined filing of **DPL** and **DP&L. DPL** is 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;
- availability and price of capacity;
- 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 **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;
- changes in tax laws and the effects of our strategies to reduce tax payments;
- 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.

Item 1 – Business

OVERVIEW

DPL is a regional energy company incorporated in 1985 under the laws of Ohio. **DPL** was acquired by The AES Corporation on November 28, 2011 and **DPL's** stock is owned by an AES subsidiary.

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 services are still regulated. **DP&L** has the exclusive right to provide such service to its approximately 517,000 customers located in West Central Ohio. Additionally, **DP&L** procures and provides 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 five coal-fired power stations. Beginning in 2014, **DP&L** no longer supplied 100% of the generation for SSO customers and starting January 2016, SSO is now 100% competitively bid. 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 sold electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

DPLER was sold by **DPL** on January 1, 2016. DPLER sold competitive retail electric service, under contract, to residential, commercial and industrial customers. DPLER had approximately 125,000 customers located throughout Ohio. DPLER's operations included those of its wholly-owned subsidiary MC Squared through April 1, 2015, when DPLER sold MC Squared. Approximately 110,000 of DPLER's customers were also electric distribution customers of **DP&L**. DPLER did not own any transmission or generation assets, and it purchased all of its electric energy from **DP&L** 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. Effective February 1, 2016, DPLE was renamed AES Ohio Generation, LLC. **DPL** owns all of the common stock of its subsidiaries.

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 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 cost recoveries in customer rates relate to expected future costs.

EMPLOYEES

DPL and its subsidiaries employed 1,219 people at January 31, 2016. At that date, 1,189 of these employees were employed by **DP&L**. Approximately 60% of the employees of **DPL** and its subsidiaries are under a collective bargaining agreement which expires on October 31, 2017.

SERVICE COMPANY

Effective January 1, 2014, the Service Company began providing services including accounting, legal, human resources, information technology and other services of a similar nature on behalf of companies that are part of the U.S. SBU, including, among other companies, **DPL** and **DP&L**. The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable allocations. This includes ensuring that the regulated businesses served, including **DP&L**, are not subsidizing costs incurred for the benefit of other businesses.

ELECTRIC OPERATIONS AND FUEL SUPPLY

2015 Summer Generating Capacity
(in MW)

Summer Generating Capacity	Coal fired	Combustion Turbines, Diesel Units and Solar	Total
DPL	2,078	988	3,066
DP&L	2,078	432	2,510

DPL's present summer generating capacity, including peaking units, is 3,066 MW. Of this capacity, 2,078 MW, or 68%, is derived from coal-fired steam generating stations and the balance of 988 MW, or 32%, consists of combustion turbines, diesel peaking units and solar.

DP&L's present summer generating capacity, including peaking units, is 2,510 MW. Of this capacity, 2,078 MW, or 83%, is derived from coal-fired steam generating stations and the balance of 432 MW, or 17%, 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 Dynegy, Inc. 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. 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 2015, Duke Energy finalized its sale of its interest in the Killen, Stuart, Conesville Unit 4, Miami Fort 7 and 8 and Zimmer generating stations to various subsidiaries of Dynegy, Inc.

In 2015, we generated 97% of our electric output from coal-fired units and 3% 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: **DPL** Portion (b)	Approximate Summer MW Rating: Total
Coal Units					
Killen - Unit 2	C	DP&L	Wrightsville, OH	402	600
Stuart - Units 1 through 4	C	DP&L	Aberdeen, OH	808	2,308
Conesville - Unit 4	C	AEP Generation	Conesville, OH	129	780
Miami Fort - Units 7 & 8	C	Dynegy	North Bend, OH	368	1,020
Zimmer - Unit 1	C	Dynegy	Moscow, OH	371	1,320
Sub-total coal				2,078	6,028
Solar, Combustion Turbines (CT) or Diesel					
Hutchings CT Unit 7	W	DP&L	Miamisburg, OH	25	25
Yankee Units 1 - 7	W	DP&L	Centerville, OH	101	101
Yankee Solar	W	DP&L	Centerville, OH	1	1
Monument Diesels	W	DP&L	Dayton, OH	12	12
Tait Diesels	W	DP&L	Dayton, OH	10	10
Sidney Diesels	W	DP&L	Sidney, OH	12	12
Tait CT Units 1 - 3	W	DP&L	Moraine, OH	256	256
Killen CT	C	DP&L	Wrightsville, OH	12	18
Stuart Diesels	C	DP&L	Aberdeen, OH	3	10
Montpelier CT Units 1 - 4	W	DPLE	Poneto, IN	236	236
Tait CT Units 4 - 7	W	DPLE	Moraine, OH	320	320
Sub-total solar, CT or diesel				988	1,001
Total approximate summer generating capacity				3,066	7,029

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

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.

On December 30, 2014, after receipt of all necessary regulatory approvals, **DP&L** sold its 31% ownership interest (186 MW) in East Bend Unit 2 to Duke Energy, Kentucky, Inc., which is the operator of the Unit and was the 69% owner.

We have all of the coal volume needed to meet our wholesale sales obligations for 2016 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 2016.

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

	Average cost of Fuel Consumed (cents per kWh)		
	2015	2014	2013
DPL	**2.48**	2.52	2.43
DP&L	**2.42**	2.45	2.40

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.

MARKET STRUCTURE

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

DP&L's delivery service to all retail customers as well as the provisions of its SSO service are regulated by the PUCO. In addition, certain 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 the customer's retail electric supplier. **DP&L's** transmission rates and wholesale electric rates 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 changes, the cost basis upon which the rates are set and other service-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 of both **DPL** and **DP&L**. See Note 3 – Regulatory Assets and Liabilities of Notes to **DPL's** Consolidated Financial Statements and Note 3 – Regulatory Assets and Liabilities of Notes to **DP&L's** Financial Statements.

COMPETITION AND REGULATION

Ohio Matters

Ohio Retail Rates
Ohio law requires that all Ohio distribution utilities file either an ESP or MRO to establish rates for SSO service. The terms and conditions of **DP&L's** current SSO are provided under the ESP that was decided by PUCO order dated September 4, 2013 (2012 ESP). Although it has been in effect since January 2014, **DP&L's** 2012 ESP remains on appeal before the Ohio Supreme Court.

The 2012 ESP allows **DP&L** to collect a non-bypassable SSR equal to $110 million per year from 2014 - 2016. It allowed for **DP&L** to recover its PJM-related transmission charges, alternative energy costs, fuel and purchased power costs, and established a SEET threshold of 12% ROE. It also required **DP&L** to conduct competitive bid auctions to procure generation supply for SSO service. **DP&L's** own generation was phased-out of supplying SSO service over the three-year period. Beginning January 1, 2016, **DP&L's** SSO will be 100% sourced through the competitive bid.

On October 30, 2015, **DP&L** publicly announced its intent to file an application to increase its distribution rates at the PUCO. On November 30, 2015, **DP&L** filed its distribution rate case using a 12-month test year of June 1, 2015 to May 31, 2016 to measure revenue and expenses and a date certain of September 30, 2015 to measure its asset base. **DP&L** is seeking an increase to distribution revenues of $65 million per year. **DP&L** has asked for recovery of certain regulatory assets as well as two new riders that would allow **DP&L** to recover certain costs on an ongoing basis. It has proposed a modified straight-fixed variable rate design in an effort to decouple distribution revenues from electric sales. If approved as filed, the rates are expected to have an effect of approximately 4% on a typical residential customer bill based on rates in effect at the time of the filing.

On February 22, 2016 **DP&L** filed an ESP that would go into effect beginning January 1, 2017. As part of this filing, **DP&L** is seeking a Reliable Electricity Rider for 10 years, based on the variance between the proposed revenue requirement and the actual revenues net of operating costs of the generation units. This plan establishes the terms and conditions for **DP&L's** SSO beginning June 1, 2017 to customers that do not choose a competitive retail electric supplier. In its plan, **DP&L** recommends including renewable energy attributes as part of the product that is competitively bid, and seeks recovery of approximately $10.0 million of regulatory assets. The plan also proposes a new Distribution Investment Rider to allow **DP&L** to recover costs associated with future distribution equipment and infrastructure needs. Additionally, the plan establishes new riders set initially at zero, related to energy reductions from **DP&L's** energy efficiency programs, and certain environmental liabilities **DP&L** may incur. There can be no assurance that the ESP will be approved as filed or on a timely basis, and if the ESP is not approved on a timely basis or if the final ESP provides for terms that are more adverse than those submitted in **DP&L's** application, our results of operations, financial condition and cash flows could be materially impacted.

As directed by the PUCO, **DP&L** filed a corporate separation plan in December 2013 stating its plan to transfer or sell its generation assets. In July 2014, **DP&L** publicly announced its decision not to sell **DP&L's** generation assets at this time, but to maintain its plans to transfer or sell the assets in accordance with PUCO orders by January 1, 2017. The PUCO approved **DP&L's** plan to separate its generation assets with minor modifications.

The costs associated with providing high voltage transmission service and wholesale electric sales and ancillary services are subject to FERC jurisdiction. While **DP&L** has market-based rate authority for wholesale electric sales, **DP&L** would be required to file an application at FERC under section 101 of Title 18 of the Code of Federal Regulations to change any of its cost-based transmission or ancillary service rates.

Ohio law and the PUCO rules contain targets relating to renewable energy, peak 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. **DP&L** is in full compliance with energy efficiency and peak demand reduction targets. **DP&L** is reported to be in full compliance with all renewable targets. DPLER was also reported to be in full compliance.

Ohio Senate Bill 310 (SB 310) was introduced in 2014 and became effective September 12, 2014. The new law changes several aspects of the renewable energy and energy efficiency sections of Ohio law. The law freezes the renewable energy requirements at 2014 levels for 2015 and 2016 and the energy efficiency requirements if a utility modifies its portfolio plan. SB 310 removed the advanced energy requirement and removed the requirement that renewable energy had to be procured through facilities located within the state. **DP&L** did not file an amended portfolio plan, thereby extending its current plan through 2016. **DP&L** recovers the costs of its compliance with Ohio energy efficiency and renewable energy standards through separate riders which are reviewed and audited by the PUCO.

As a member of PJM, **DP&L** receives revenues from the RTO related to **DP&L's** transmission and generation assets and incurs costs associated with its load obligations for retail customers. Ohio law 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 associated with the portion of SSO **DP&L** supplied with its generation. Beginning January 1, 2016, **DP&L's** generation will no longer be used to supply SSO, therefore **DP&L** will no longer recover its PJM RPM and market based transmission costs through retail rates. It will continue to recover non-market based transmission costs through its TCRR-N. RPM capacity costs and revenues are discussed further in Item 1A - Risk Factors.

DP&L is subject to a SEET threshold and is required to apply general rules for calculating earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings during a given calendar year. Through the 2012 ESP, the PUCO established **DP&L's** ROE SEET threshold at 12%. On May 15, 2015, **DP&L** filed its application to demonstrate that it did not have significantly excessive earnings for calendar year 2014. A stipulation was reached with the PUCO staff agreeing that **DP&L** did not exceed the SEET threshold for 2014. A hearing was held and the PUCO issued an order approving the SEET Stipulation. In future years, the SEET could have a material effect on results of operations, financial condition and cash flows.

Competitive Generation
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 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. Beginning January 1, 2016, 100% of SSO load will be supplied through the competitive bid auction. After that date, customer switching will no longer have an effect on **DP&L's** margin.

Like other electric utilities and energy marketers, **DP&L** and DPLE may sell or purchase electric products in 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.

Capacity Auction Price
The PJM capacity base residual auction for the 2018/19 period cleared at a price of $165/MW-day for our RTO area. The prices for the periods 2017/18, 2016/17 and 2015/16 were $152/MW-day, $134/MW-day and $136/MW-day, respectively, based on previous auctions. As discussed below, a new CP program was approved by the FERC, which will phase in and replace RPM as of the 2018/19 period. During the phase-in period, the RPM auction results were modified based on transitional auctions that were conducted in the third quarter of 2015. We cannot predict the outcome of future auctions but based on actual results attained, we estimate that a hypothetical increase or decrease of $10/MW-day in the capacity auction price would result in an annual impact to net income of approximately $6.9 million and $5.6 million for **DPL** and **DP&L**, respectively. These estimates do not, however, take into consideration the other factors that may affect capacity revenues and costs such as our generation capacity, the levels of wholesale revenues and our retail customer load. These estimates are discussed further within Commodity Pricing Risk under the Item 7A - Quantitative and Qualitative disclosures about Market Risk.

On June 9, 2015, the FERC approved a proposal made by PJM to implement a new CP program. The FERC's conditions on approval include requiring PJM to make additional filings to change certain energy market rules to coordinate better with the new CP program and to make annual filings on the CP performance hours used in its calculations. The FERC's order approved transitional mechanisms under which the results of the auctions under the RPM program for the 2016/17 and 2017/18 periods would be modified based on transitional CP auctions that were held in the third quarter of 2015. The first full CP auction was also held in the third quarter of 2015 for the 2018/19 period.

The PJM CP base residual auction for the 2018/19 period cleared at a price of $165/MW-day for our RTO area. PJM also conducted CP transition auctions for the 2016/17 and 2017/18 periods to give market participants the option to upgrade to the new CP product. The CP transition auction for the 2016/17 period cleared at a price of $134/MW-day and the auction for the 2017/18 period cleared at a price of $152/MW-day.

As approved, the CP program offers the potential for higher capacity revenues, combined with substantially increased penalties for non-performance or under-performance during certain periods identified as "capacity performance hours". This linkage between non- or under-performance during certain specific hours means that a generation unit that is generally performing well on an annual basis, may incur substantial penalties if it happens to be unavailable for service during some capacity performance hours. Similarly, a generation unit that is generally performing poorly on an annual basis may avoid such penalties if its outages happen to occur only during hours that are not capacity performance hours. An annual "stop-loss" provision exists that limits the size of penalties to 150% of the net Cost of New Entry, which is a value computed by PJM. This level is likely to be larger than the capacity price established under the CP program, so that the potential exists that participation in the CP program could result in capacity penalties that exceed capacity revenues.

At present, **DP&L** is unable to project whether the CP program will be beneficial or negative to **DP&L's** operations, but the results could be material to **DP&L's** operations.

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 SIPs) 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 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.

  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 $0.9 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 or a loss cannot be reasonably estimated. 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. See Note 12 – Contractual Obligations, Commercial Commitments and Contingencies – "Environmental Matters" of Notes to **DPL's** Consolidated Financial Statements and Note 11 – Contractual Obligations, Commercial Commitments and Contingencies – "Environmental Matters" of Notes to **DP&L's** Financial Statements for more information regarding environmental risks, laws and regulations and legal proceedings to which we are and may be subject to in the future.

  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.

Environmental Matters Related to Air Quality

Clean Air Act Compliance

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

Cross-State Air Pollution Rule

On July 6, 2011, the EPA announced a rule to require further reduction of SO_2 and NO_X emissions from power plants in 28 states, including Ohio, that contribute to ozone and/or fine particle pollution in other states. This rule, known as CSAPR, required initial compliance by January 1, 2012 for SO_2 and annual NO_X reductions, and May 1, 2012 for ozone season reductions. In August 2012, the D.C. Circuit Court issued a ruling vacating CSAPR.

In April 2014, the U.S. Supreme Court reversed the 2012 decision by the D.C. Circuit Court, reinstating CSAPR, and remanded the case to the D.C. Circuit Court for further proceedings consistent with the U.S. Supreme Court decision. In June 2014, the U.S. Department of Justice, on behalf of the USEPA, filed a motion with the D.C. Circuit Court to lift the stay on CSAPR and on October 23, 2014, the D.C. Circuit Court lifted the stay. On November 21, 2014, EPA announced a Notice of Data Availability (NODA) and a final interim rule that addresses allocations of emission allowances to certain units for compliance with the CSAPR. These allowance allocations, which supersede the allocations announced in a 2011 NODA, reflect the changes to CSAPR made in subsequent rulemakings, as well as "re-vintaging" of previously recorded allowances so as to account for the impact of the tolling of the CSAPR deadlines pursuant to an order issued by the D.C. Circuit Court. On July 28, 2015, the D.C. Circuit Court held invalid the 2014 SO_2 emissions budgets for Alabama, Georgia, South Carolina and Texas, as well as the 2014 ozone-season NO_X budgets for Florida, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia, and West Virginia. It rejected all of the petitioners' other challenges to the rule. The budgets remain in place pending reconsideration. On December 3, 2015, the USEPA published the proposed CSAPR Update Rule to address interstate air quality impacts with respect to the 2008 Ozone NAAQS. While we are currently unable to determine the full impact of the reinstatement of CSAPR, the rule and future revisions may have a material impact on **DP&L**.

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, with a compliance date of April 16, 2015. All of our operating EGUs are currently achieving compliance through control technologies in place.

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** is in material compliance with this rule.

National Ambient Air Quality Standards

On January 25, 2013, the USEPA published the 2012 PM 2.5 standard of 12.0 micrograms per cubic meter. On January 15, 2015, USEPA published its final designations for the 2012 standard. No counties containing **DP&L** operated generating facilities were designated as non-attainment; however, several co-owned units are located in non-attainment counties. Attainment in those counties will be required by the end of 2021. We cannot predict the effect the revisions to the PM 2.5 standard will have on **DP&L's** financial condition or results of operations.

On October 1, 2015, the USEPA released a final rule lowering the 8-hour ozone standard from 0.075 to 0.070 ppm. Ozone attainment determinations are expected by October 1, 2017. 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. We cannot predict the effect the revisions of the ozone standard will have on **DP&L's** financial condition or results of operations.

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

Effective August 23, 2010, the USEPA implemented its revisions to its primary NAAQS for SO_2 replacing the previous 24-hour standard and annual standard with a one-hour standard. Non-attainment areas will be required to meet the 2010 standard by October 2018. On August 21, 2015, the USEPA finalized a data requirements rule for air agencies to ascertain attainment characterization more extensively across the country by additional modeling and/or monitoring requirements of areas with sources that exceed specified thresholds of SO_2 emissions. The rule could require the installation of monitors at one or more of **DP&L's** coal-fired power plants and result in additional non-attainment designations that could impact our operations. **DP&L** is unable to determine the effect of the rule on its operations.

On May 5, 2004, the USEPA issued its proposed regional haze rule, which addresses how states should determine the Best Available Retrofit Technology (BART) for sources covered under the regional haze rule. Final rules were published July 6, 2005, providing states with several options for determining whether sources in the state should be subject to BART. Numerous units owned and operated by us will be affected by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

Carbon Dioxide and Other Greenhouse Gas Emissions

In January 2014, the USEPA proposed revised GHG New Source Performance Standards (NSPS) for new EGUs under CAA subsection 111(b), which would require new EGUs to limit the amount of CO_2 emitted per megawatt-hour. The final NSPS was published in the Federal Register on October 23, 2015, and regulates CO_2 emissions from new, modified and reconstructed fossil-fuel-fired power plants. The final rules are effective immediately.

On October 23, 2015, the USEPA's final CO2 emission rules for existing power plants (called the Clean Power Plan or "CPP") were published in the Federal Register with an effective date of December 22, 2015. The CPP provides for interim emissions performance rates that must be achieved beginning in 2022 and final emissions performance rates that must be achieved by 2030. Prior to the rule's publication in the Federal Register, fifteen states, including Ohio, filed a petition in the D.C. Circuit Court seeking a stay of the CPP, which was denied by the D.C. Circuit Court in September 2015. On October 23, 2015, several states and industry groups filed petitions in the D.C. Circuit Court challenging the CPP as published in the Federal Register, including a twenty-four state consortium that includes Ohio. These state petitioners, as well as industry groups separately challenging the rule, have filed motions with the D.C. Circuit Court requesting a stay of the rule. On January 21, 2016, the D.C. Circuit Court issued an order denying motions for stay of the rule, however on February 9, 2016, the U.S. Supreme Court stayed the rule pending action by the D.C. Circuit Court, and the stay will continue until the U.S. Supreme Court renders a decision if the D.C. Circuit Court action is appealed. The D.C. Circuit Court has also issued orders consolidating the current pending challenges to the CPP under the lead case, West Virginia v. EPA. On October 23, 2015, North Dakota filed a petition for review of the Greenhouse Gas NSPS in the D.C. Circuit Court, and a coalition of environmental groups have moved to intervene on behalf of EPA in both the CPP and NSPS litigation. Additional legal challenges to the CPP and NSPS are expected. It is too early to determine how the stay will impact implementation of the CPP. We are currently reviewing the CPP and Greenhouse Gas NSPs and assessing the impact on our operations. Our business, financial condition or results of operations could be materially and adversely affected by these rule.

Approximately 97% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 11 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

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 startups. 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 June 2000, the USEPA issued an NOV to the **DP&L**-operated Stuart generating station (co-owned by **DP&L**, Dynegy 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 Dynegy) 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 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. In addition, Zimmer received an NOV from the USEPA dated December 16, 2014 alleging violations in opacity on two dates in 2014. **DP&L** is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of these matters. Dynegy 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.

In January 2015, **DP&L** received NOVs from the USEPA alleging violations in opacity at the Stuart and Killen generating stations in 2014. **DP&L** is in the process of discussions with the USEPA on these NOVs. **DP&L** is unable to predict the outcome of these matters.

Notices of Violation Involving Wholly-Owned Stations

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 of the six coal-fired units at the Hutchings Station, **DP&L** believes that the USEPA is unlikely to pursue the NSR complaint.

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

Clean Water Act – Regulation of Water Intake

On May 19, 2014, the USEPA finalized new regulations pursuant to the CWA governing existing facilities that have cooling water intake structures. The rules require an assessment of impingement and/or entrainment of organisms as a result of cooling water withdrawal. Although we do not yet know the full impact the final rules will have on our operations, the final rules may require material changes to the intake structure at Stuart Station to reduce impingement with the possibility of additional site specific requirements for reducing entrainment. We do not believe the final rules will have a material impact on operations at any of the other **DP&L**-operated facilities.

Clean Water Act – Regulation of Water Discharge

In December 2006, **DP&L** submitted a renewal application for the Stuart generating 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. A hearing before the Commission is scheduled for March 2016. Depending on the outcome of the appeal process, the effects on **DP&L's** operations could be material.

In September 2009, the USEPA announced that it would be revising technology-based regulations governing water discharges from steam electric generating facilities. The proposed rule was released on June 7, 2013, and a final rule was published on November 3, 2015 with an effective date of January 4, 2016. Under the provisions of the final rule, discharges from fly ash ponds and bottom ash ponds will eventually be prohibited and treatment will be required for water discharges associated with flue gas desulfurization equipment. While we are still evaluating the impacts of the final rule, we anticipate that implementation of the requirements will have a material adverse effect on our results of operations, financial condition and cash flows.

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. On August 16, 2006, an Administrative Settlement Agreement and Order on Consent (ASAOC) for the site was executed and became effective among a group of PRPs, not including **DP&L**, and the USEPA. 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 (the District Court) against **DP&L** and numerous other defendants alleging that **DP&L** and the other defendants contributed to the contamination at the 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 District Court judge 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 District Court judge, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from **DP&L** that were allegedly delivered by truck directly to the landfill. Discovery, including depositions of past and present **DP&L** employees, was conducted in 2012. On February 8, 2013, the District Court judge 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 under the August 15, 2006 ASAOC. That summary judgment ruling was appealed on March 4, 2013, and on July 14, 2014, a three-judge panel of the U.S. Court of Appeals for the 6th Circuit affirmed the lower Court's ruling and subsequently denied a request by the PRP group for rehearing. On November 14, 2014, the PRP group appealed the decision to the U.S. Supreme Court, but the writ of certiorari was denied by the Court on January 20, 2015. On April 5, 2013, the PRP group entered into a second ASAOC (the "2013 ASAOC") relating primarily to vapor intrusion from under some of the buildings at the landfill site. On April 13, 2013, as amended July 30, 2013, the PRP group filed another civil complaint against **DP&L** and numerous other defendants alleging that each defendant contributed to the contamination of the site by delivering hazardous waste to the site or by releasing hazardous waste on other sites that migrated to the landfill site.

On February 18, 2014, after considering various motions and alternative grounds to dismiss, the District Court judge dismissed some of the alleged grounds for relief that the PRP group had made, but ruled in the PRP group's favor with respect to motions to dismiss the case in its entirety finding, among other things, that the 2013 ASAOC involved a different scope of work and thus the contributions sought were not seeking the same remedy that had been dismissed in the first civil suit. Appeals of this ruling are pending before the 6th Circuit Court of Appeals.

On January 14, 2015, the PRP group served **DP&L** and other defendants a request for production of documents related to any waste management or waste disposal surveys. Information responsive to this request was provided on February 17, 2015. In addition, on January 16, 2015, the USEPA issued a Special Notice Letter and Section 104(e) Information Request to **DP&L** and other defendants, requesting historical information related to waste management practices that may be relevant to the site. **DP&L** responded to this request on March 27, 2015. In June 2015, **DP&L** was again requested to grant access to the **DP&L** service building property for the purpose of collecting groundwater samples from selected monitoring wells. **DP&L** granted access and groundwater sampling took place in June 2015. As a result of an August 11, 2015 meeting among the parties, the parties agreed to stay the case in order to explore the possibility of a negotiated resolution of some or all of the issues. The stay ended February 7, 2016 without resolution of claims against **DP&L**. A trial date has not been set. **DP&L** is unable to predict the outcome of these actions by the plaintiffs and USEPA. Additionally, the District Court's 2013 ruling and the Court of Appeals' affirmation of that ruling in 2014 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 and any future matters, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on its business, financial condition or results of operations.

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

On April 7, 2010, the USEPA published an Advance Notice of Proposed Rulemaking announcing that it is reassessing existing regulations governing the use and distribution in commerce of polychlorinated biphenyls (PCBs). While this reassessment is in the early stages and the USEPA is seeking information from potentially affected parties on how it should proceed, the outcome may have a material effect on **DP&L**. A proposed rule is expected in 2016, with a final rule expected in 2017. At present, **DP&L** is unable to predict the impact this initiative will have on its results of operations, financial condition or cash flows.

Regulation of Ash Ponds

The USEPA released a final rule on December 19, 2014, designating coal combustion residuals that are not beneficially reused as non-hazardous solid waste under the Resource Conservation Recovery Act (RCRA) Subtitle D. The rule became effective on October 19, 2015, and applies new detailed management practices to new and existing landfills and surface impoundments, including lateral expansions of such units. In 2015, **DP&L** increased the ARO related to ash ponds by a net $40.3 million as a result of this rule.

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 CWA 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.

Capital Expenditures for Environmental Matters

DP&L's environmental capital expenditures were approximately $6.5 million, $3.6 million and $2.0 million in 2015, 2014 and 2013, respectively. **DP&L** has projected $14.0 million in environmental-related capital expenditures for 2016.

ELECTRIC SALES AND REVENUES

DPL was structured in two operating segments, **DP&L** and DPLER, prior to the DPLER sale agreement. See Note 14 – Business Segments of Notes to **DPL's** Consolidated Financial Statements for more information on **DPL's** segments. The following table sets forth **DPL's, DP&L's** and DPLER's electric sales for the years ended December 31, 2015, 2014 and 2013, as well as billed electric customers as of December 31, 2015, 2014 and 2013.

	Year ended December 31, 2015		Year ended December 31, 2014		Year ended December 31, 2013	
	Electric sales (millions of kWh)	Billed electric customers (end of period)	Electric sales (millions of kWh)	Billed electric customers (end of period)	Electric sales (millions of kWh)	Billed electric customers (end of period)
DPL [(a)]	14,738	516,708	14,695	515,622	15,702	514,926
DP&L [(b)]	16,424	516,708	18,613	515,622	19,423	514,926
DPLER [(c)]	5,928	124,866	9,717	260,097	9,733	308,047

(a) Electric sales excludes 1,976 million kWh, 4,068 million kWh and 3,859 kWh relating to DPLER for the years ended December 31, 2015, 2014 and 2013, respectively, and Billed electric customers excludes DPLER customers outside of the **DP&L** service territory of 14,147 customers, 128,861 customers, and 177,744 customers for the years ended December 31, 2015, 2014 and 2013, respectively.

(b) Included within this line are 3,952 million kWh, 5,649 million kWh and 5,874 million kWh of power that **DP&L** sold to DPLER within the **DP&L** service territory for the years ended December 31, 2015, 2014 and 2013, respectively.

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

HOW TO CONTACT DPL AND DP&L

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'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.

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 that we face.

Our electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and/or maintenance expenses, increased fuel or purchased power costs and other significant liabilities for which we may not have adequate insurance coverage.

We operate coal, oil and natural gas generating facilities, which involve certain risks that can adversely affect energy costs, output and efficiency levels. These risks include:

- increased prices for fuel and fuel transportation as existing contracts expire or as such contracts are adjusted through price re-opener provisions or automatic adjustments;
- unit or facility outages due to a breakdown or failure of equipment or processes;
- disruptions in the availability or delivery of fuel and lack of adequate inventories;
- shortages of or delays in obtaining equipment;
- loss of cost-effective disposal options for solid waste generated by the facilities;
- labor disputes or work stoppages by employees;
- accidents and injuries;
- reliability of our suppliers;

- inability to comply with regulatory or permit requirements;
- operational restrictions resulting from environmental permit limitations or governmental interventions;
- construction delays and cost overruns;
- disruptions in the delivery of electricity;
- the availability of qualified personnel;
- events occurring on third party systems that interconnect to and affect our system;
- operator error; and
- catastrophic events such as fires, explosions, cyber-attacks, terrorist acts, sabotage acts of war, pandemic events, or natural disasters such as floods, earthquakes, tornadoes, severe winds, ice or snow storms, droughts, or other similar occurrences affecting our generating facilities, as well as our transmission and distribution systems.

The above risks could result in unscheduled plant outages, unanticipated operation and/or maintenance expenses, increased capital expenditures, and/or increased fuel and purchased power costs, any of which could have a material adverse effect on our financial condition, results of operations and cash flows. If unexpected plant outages occur frequently and/or for extended periods of time, this could result in adverse regulatory action and/or reduced wholesale revenues.

Additionally, as a result of the above risks and other potential hazards associated with the power generation industry, we may from time to time become exposed to significant liabilities for which we may not have adequate insurance coverage. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. The control and management of these risks depend upon adequate development and training of personnel and on the existence of operational procedures, preventative maintenance plans and specific programs supported by quality control systems which reduce, but do not eliminate, the possibility of the occurrence and impact of these risks.

The hazardous activities described above can also cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. We maintain an amount of insurance protection that we believe is adequate, but there can be no assurance that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A successful claim for which we are not fully insured could hurt our financial results and materially harm our financial condition. Further, due to rising insurance costs and changes in the insurance markets, we cannot provide assurance that insurance coverage will continue to be available on terms similar to those presently available to us or at all. Any such losses not covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows.

In addition, 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 decreased revenues and/or increased expenses that could have a material adverse effect on our results of operations, financial condition and cash flows.

We have constructed and placed into service FGD facilities and other equipment to better monitor environmental compliance at our base-load generating stations. If there is significant operational failure of such equipment at the generating stations, we may not be able to meet emission requirements at such generating stations. 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 increased operating costs, 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.

We are reliant upon the performance of co-owned generation stations which are operated by our co-owners for approximately 42% of our base-load generation.

Since approximately 42% 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 with our own, or lack of control over costs (such as fuel costs) incurred at these stations could have an adverse effect on us. In addition, certain of our co-owners have either taken steps to sell their co-ownership interest in these co-owned generation stations or have expressed an interest in selling such generation facilities. Any sale of these co-owned generation stations by a co-owner to a third party could enhance the risk of a misalignment of interests, lack of cost control and other operational failures.

We may not always be able to recover our costs to deliver electricity to our retail customers. 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, requires all Ohio distribution utilities to file either an ESP or MRO, and established a significantly excessive earnings test for Ohio public utilities that compares a utility's earnings to the earnings of other companies with similar business and financial risks. The PUCO order in the 2012 ESP case changed **DP&L's** rate structure and the ability to recover certain costs, which affects our results of operations, cash flows and financial condition. On February 22, 2016, **DP&L** filed a new ESP with the PUCO. There can be no assurance that the ESP will be approved as filed or on a timely basis, and if the ESP is not approved on a timely basis or if the final ESP provides for terms that are more adverse than those submitted in **DP&L's** application, our consolidated results of operations, financial condition and cash flows could be materially impacted. **DP&L's** current ESP, new ESP filing and certain filings made by us in connection with our ESPs are further discussed in Item 1 - Business - Competition and Regulation.

In Ohio, retail generation rates are no longer subject to cost-based regulation, while the distribution and transmission businesses are still regulated. Even though 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 also is 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. 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 the recovery of these 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. Please see Item 1 - Business - Competition and Regulation for additional information about the regulatory framework.

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

SB 221 contained targets relating to renewable energy, renewable energy, peak demand reduction and energy efficiency standards. SB 310 was passed in 2014 and modified the energy efficiency and renewable targets. It eliminated the advanced energy targets and the "in state" requirement for renewable energy. 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 2027. Peak demand reduction targets began in 2009 with increases in required percentages each year, up to 7.75% by 2020. The renewable energy standards have increased our costs and are expected to continue to increase (and could materially increase) these costs. **DP&L** is entitled to recover costs associated with its renewable 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.

The availability and cost of fuel and other commodities have experienced and could continue to experience significant volatility and we may not be able to hedge the entire exposure of our operations from availability and price volatility, and substantially all of our electricity is generated by coal and a majority of our supply of coal comes from one supplier.

Our business is sensitive to changes in the price of coal, the primary fuel we use to produce electricity, and to changes in the prices of natural gas, and other fuels that are combusted in generation facilities. In addition, changes in the prices of steel, copper and other raw materials can have a significant impact on our costs. We also are dependent on purchased power, in part, to meet our seasonal planning reserve margins. Any changes in fuel prices could affect the prices we charge, our operating costs and our competitive position with respect to our products and services.

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. In addition, market prices for power sales are volatile and not subject to control by any market participant. If market prices for power sales do not fully recover the costs of fuel, we would take steps to reduce our contract takes of fuel, but contractual requirements to take minimum amounts could cause an increase in fuel inventories and adverse financial effects. If in the future we are unable to timely or fully recover our fuel and purchased power costs from the market, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Approximately 97% of the energy we produced in 2015 was generated by coal. While we have a majority of our coal requirements for the three-year period ending December 31, 2018 under long-term contracts, the balance is yet to be purchased and will be purchased under a combination of long-term contracts, short-term contracts and on the spot market. Prices can be highly volatile in both the short-term market and on the spot market. The coal market 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 developments such as 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. In addition, pricing provisions in some of our coal contracts with terms of one year or more allow for price changes under certain circumstances.

Because of our substantial dependence on coal to meet customer demand for electricity, our business and operations could be materially adversely affected by unexpected price volatility in the coal market, price increases pursuant to the provisions of certain of our long-term coal contracts, and the continued regulatory and political scrutiny of coal. As discussed below, regulators, politicians and non-governmental organizations have expressed concern about GHG emissions and are taking actions which, in addition to the potential physical risk associated with climate change, could have a material adverse impact on our results of operations, financial condition and cash flows. Our dependence on coal also means that the output of our generation fleet can be greatly affected by the costs of other fuels combusted by generation facilities that compete with our coal-fired EGUs. Natural gas prices over the last several years have been relatively low and some gas-fired generators that previously were primarily used during periods of peak and intermediate electric demand are now running even during periods of relatively low demand. This has caused many coal-fired generators, including ours, to run fewer hours during these periods of base-load demand. If natural gas prices continue to remain low relative to their historic levels, it could have a material adverse effect on our results of operations, financial condition and cash flows.

In addition, all of our coal supply is mined by unaffiliated suppliers or third parties. Our goal is to carry a 25 - 35 day system supply of coal to offset unforeseen occurrences such as equipment breakdowns and transportation or mine delays. Moreover, a majority of our coal under contract for the three-year period ending December 31, 2018 comes from a single supplier. In recent years, the coal industry has undergone significant restructuring as a result of debt restructurings, bankruptcy proceedings and other factors. Further restructuring may result in a failure of our suppliers to fulfill their contractual obligations or fewer suppliers and, consequently, increased dependency on any one supplier. Any significant disruption in the ability of our suppliers, particularly our most significant suppliers, to mine or deliver coal or other fuel, or any failure on the part of our suppliers to fulfill their contractual obligations could have a material adverse effect on our business. In the event of disruptions or failures, there can be no assurance that we would be able to purchase power or find another supplier of fuel on similarly favorable terms.

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 of such costs, and we are responsible for our proportionate share of any increase in actual fuel costs.

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 CSAPR. 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.

Regulators, politicians and non-governmental organizations have expressed concern about GHG emissions and are taking actions which, in addition to the potential physical risks associated with climate change, could have a material adverse impact on our results of operations, financial condition and cash flows.

One byproduct of burning coal and other fossil fuels is the emission of GHGs, including CO_2. At the federal, state and regional levels, policies are under development or have been developed to regulate GHG emissions, including by effectively putting a cost on such emissions to create financial incentives to reduce them. In 2015, **DP&L** emitted approximately 11 million tons of CO_2 from its power plants. **DP&L** uses CO_2 emission estimation methodologies supported by "The Greenhouse Gas Protocol" reporting standard on GHG emissions. **DP&L's** CO_2 emissions are calculated from actual fuel heat inputs and fuel type CO_2 emission factors.

Any existing or future international, federal, state or regional legislation or regulation of GHG emissions could have a material adverse impact on our financial performance. The actual impact on our financial performance will depend on a number of factors, including among others, the degree and timing of GHG emissions reductions required under any such legislation or regulations, the price and availability of offsets, the extent to which market-based compliance options are available, the extent to which we would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the impact of such legislation or regulation on our ability to recover costs incurred through rate increases or otherwise. As a result of these factors, our cost of compliance could be substantial and could have a material adverse impact on our results of operations, financial condition and cash flows. 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.

Furthermore, according to the Intergovernmental Panel on Climate Change, physical risks from climate change could include, but are not limited to, increased runoff and earlier spring peak discharge in many glacier and snow-fed rivers, warming of lakes and rivers, an increase in sea level, changes and variability in precipitation and in the intensity and frequency of extreme weather events. Physical impacts may have the potential to significantly affect our business and operations. For example, extreme weather events could result in increased downtime and operation and maintenance costs at our electric power generation facilities and our support facilities. Variations in weather conditions, primarily temperature and humidity, would also be expected to affect the energy needs of customers. A decrease in energy consumption could decrease our revenues. In addition, while revenues would be expected to increase if the energy consumption of customers increased, such increase could prompt the need for additional investment in generation capacity. Changes in the temperature of lakes and rivers and changes in precipitation that result in drought could adversely affect the operations of our fossil-fuel fired electric power generation facilities. If any of the foregoing risks materialize, costs may increase or revenues may decrease and there could be a material adverse effect on our results of operations, financial condition and cash flows.

In addition to the rules already in effect, regulatory initiatives regarding GHG emissions may be implemented in the future, although at this time we cannot predict if, how, or to what extent such initiatives would affect us. Generally, costs to comply with any regulations implemented to reduce GHG emissions, including those already promulgated, are part of the costs of providing electricity to our customers. While we might seek recovery for such costs, there can be no assurance that the PUCO will approve such requests or that we will be able to recover such costs. Finally, concerns over GHG emissions and their effect on the environment could lead to reduced demand for coal-fired power, which could have a material adverse effect on our results of operations, financial condition and cash flows. Please see Item 1 - Business - Environmental Matters for addition information of environmental matters impacting us, including those relating to regulation of GHG emissions.

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.
We are subject to various federal, state, regional and local environmental protection and health and safety laws and regulations governing, among other things, the generation, storage, handling, use, disposal and transportation of ash and other materials, some of which may be defined as hazardous materials; the use and discharge of water used in generation boilers and for cooling purposes; the emission and discharge of hazardous and other materials into the environment; and the health and safety of our employees. 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) and further reductions in GHG emissions as discussed in more detail in the previous risk factor) and limits on water use and discharge. These laws and regulations often require a lengthy and complex process of obtaining and renewing permits and other governmental authorizations from federal, state and local agencies. A violation of these laws, regulations or permits can result in substantial fines, other sanctions, permit revocation and/or facility shutdowns. 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. With respect to our largest generation station, the Stuart generating 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. **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. Under certain environmental laws, we could also be held responsible for costs relating to contamination at our past or present facilities and at third-party waste disposal sites. We could also be held liable for human exposure to such hazardous substances or for other environmental damage. From time to time we are subject to enforcement and litigation actions for claims of noncompliance with environmental laws and regulations. **DP&L** cannot assure that it will be successful in defending against any claim of noncompliance. Any alleged violation of these laws, regulations and other requirements may require us to expend significant resources to defend against any such alleged violations. Our costs and liabilities relating to environmental matters could have a material adverse effect on our results of operations, financial condition and cash flows. For example, the amount of capital expenditures required to comply with environmental laws or regulations could be impacted by the outcome of the EPA's NOVs described in this Annual Report on Form 10-K. Please see Item 1 - Business - Environmental Matters for a more comprehensive discussion of these and other environmental matters impacting us.

The use of non-derivative and derivative instruments in the normal course of business could result in losses that could negatively impact our results of operations, financial position and cash flows.
We sometimes use non-derivative and derivative instruments, such as swaps, options, futures and forwards, to manage commodity and financial risks. 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. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these instruments can involve management's judgment or the 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, a counterparty failing to perform, or the underlying transactions which the instruments are intended to hedge failing to materialize, 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 (the 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.

Our business is sensitive to weather and seasonal variations.
Weather conditions significantly affect the demand for electric power, and accordingly, our business is affected by variations in general weather conditions and unusually severe weather. As a result of these factors, our operating revenues and associated operating expenses are not generated evenly by month during the year. We forecast electric sales on the basis of normal weather, which represents a long-term historical average. Significant variations from normal weather (such as warmer winters and cooler summers) could have a material impact on our revenue, operating income and net income 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, 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.

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 retail customers through the TCRR-N 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.

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.
DP&L filed an application for authority to transfer or sell its generation assets no later than January 1, 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. Although the initial PUCO order approved our separation plan, 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.

If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.
As an owner 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 may subject us to higher operating costs or increased capital expenditures. Although 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 could have a material adverse effect on our results of operations, financial condition and cash flows.

We rely on access to the financial markets. General economic conditions and disruptions in the financial markets could adversely affect our ability to raise capital on favorable terms, or at all, and cause increases in our interest expense.

From time to time we rely on access to the capital and credit markets as a source of liquidity for capital requirements not satisfied by operating cash flows. These capital and credit markets experience volatility and disruption from time to time and the ability of corporations to raise capital can be negatively impacted. Disruptions in the capital and credit markets make it harder and more expensive to raise capital. It is possible that our ability to raise capital on favorable terms, or at all, could be adversely affected by future market conditions, and we may be unable to access adequate funding to refinance our debt as it becomes due or finance capital expenditures. The extent of any impact will depend on several factors, including our operating cash flows, the overall supply and demand in the credit markets, our credit ratings, credit capacity, the cost of financing, and other general economic and business conditions. It may also depend on the performance of credit counterparties and financial institutions with which we do 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. See Note 8 – Debt of Notes to **DPL's** Consolidated Financial Statements and Note 7 – Debt of Notes to **DP&L's** Financial Statements for information regarding indebtedness. See also Item 7A - Quantitative and Qualitative Disclosure about Market Risk for information related to market risks.

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 capacity 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, non-market based costs are being recovered from all retail customers through the TCRR-N. If in the future, however, we are unable to recover all of these costs in a timely manner 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.

Wholesale power marketing activities may add volatility to earnings.

We engage in wholesale power marketing activities that primarily involve the offering of utility-owned or contracted generation into the PJM day-ahead and real-time markets. As part of these strategies, we may also execute energy contracts that are integrated with portfolio requirements around power supply and delivery. The earnings from our wholesale marketing activities may vary based on fluctuating prices for electricity and the amount of electric generating capacity, beyond that needed to meet firm service requirements. In order to reduce the risk of volatility in earnings from wholesale marketing activities, we may at times enter into forward contracts to hedge such risk. If our hedging procedures do not operate as planned we may experience losses. In addition, the introduction of additional renewable energy, demand response or other energy supply into the PJM market could have the effect of reducing the demand for wholesale energy from other sources. This additional generation could have the impact of reducing market prices for energy and could reduce our opportunity to sell coal-fired and gas generation into the PJM market, thereby reducing our wholesale sales. Additionally, decreases in natural gas prices in the U.S. have the impact of reducing market prices for electricity, which can reduce our ability to sell excess generation on the wholesale market, as well as reduce our profit margin on wholesale sales.

Under the PJM Capacity Performance program, we could be subject to substantial changes in capacity income and/or penalties.

As the owner of generation that is a "capacity resource" within PJM, **DP&L** is subject to mandatory requirements to participate in PJM markets. The Capacity Performance program offers the potential for higher capacity prices paired with higher penalties for non-performance during times of high electricity demand. Any such penalties could have a material adverse effect on our results of operations, financial condition and cash flows. Please see Item 1 - Business - Competition and Regulation for additional information about the PJM program.

Our transmission and distribution system is subject to reliability and capacity risks.

The ongoing reliable performance of our transmission and distribution system is subject to risks due to, among other things, weather damage, intentional or unintentional damage, fires and/or explosions, plant outages, labor disputes, operator error, or inoperability of key infrastructure internal or external to us. The failure of our transmission and distribution system to fully deliver the energy demanded by customers could have a material adverse effect on our results of operations, financial condition and cash flows, and if such failures occur frequently and/or for extended periods of time, could result in adverse regulatory action. In addition, the advent and quick adaptation of new products and services that require increased levels of electrical energy cannot be predicted and could result in insufficient transmission and distribution system capacity.

Current and future conditions in the economy may adversely affect our customers, suppliers and other counterparties, which may adversely affect our results of operations, financial condition and cash flows.

Our business, results of operations, financial condition and cash flows have been and will continue to be affected by general economic conditions. Slowing global economic growth, credit market conditions, fluctuating consumer and business confidence, fluctuating commodity prices, and other challenges currently affecting the general economy, have caused and may continue to cause some of our customers to experience deterioration of their businesses, cash flow shortages, and difficulty obtaining financing. As a result, existing customers may reduce their electricity consumption and may not be able to fulfill their payment obligations to us in the normal, timely fashion. In addition, some existing commercial and industrial customers may discontinue their operations. 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. For example, 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. Furthermore, projects which may result in potential new customers may be delayed until economic conditions improve. 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. In particular, the projected economic growth and total employment in **DP&L's** service territory are important to the realization of our forecasts for annual energy sales.

Some of our suppliers, customers and other counterparties, and others with whom we transact business may be experiencing financial difficulties, which may impact their ability to fulfill their obligations to us. For example, our counterparties on forward purchase contracts and financial institutions involved in our credit facility may become unable to fulfill their contractual obligations. We may not be able to enter into replacement agreements on terms as favorable as our existing agreements. If the general economic slowdown continues for significant periods or deteriorates significantly, our results of operations, financial condition and cash flows could be materially adversely affected.

The level of our indebtedness, and the security provided for this indebtedness, could adversely affect our financial flexibility, and a material change in market interest rates could adversely affect our results of operations, financial condition and cash flows.

As of December 31, 2015, **DPL** had $2,009.4 million of indebtedness. As of December 31, 2015, **DP&L** had $762.9 million of indebtedness and total common shareholder's equity of $1,212.7 million. Of **DP&L's** indebtedness, there was $745.0 million of first mortgage bonds and tax-exempt pollution control bonds outstanding as of December 31, 2015, which are secured by the pledge of substantially all of the assets of **DP&L** under the terms of **DP&L's** First & Refunding Mortgage. This level of indebtedness and related security could have important consequences, including the following:

- increasing our vulnerability to general adverse economic and industry conditions;
- requiring us to dedicate a substantial portion of our cash flow from operations to make payments on our indebtedness, thereby reducing the availability of our cash flow to fund other corporate purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- limiting, along with the financial and other restrictive covenants in our indebtedness, our ability to borrow additional funds, as needed.

We expect to incur additional debt in the future, subject to the terms of our debt agreements and regulatory approvals for any additional **DP&L** debt. To the extent we become more leveraged, the risks described above would increase. Further, actual cash requirements in the future may be greater than expected. Accordingly, our cash flow from operations may not be sufficient to repay at maturity all of the outstanding debt as it becomes due and, in that event, we may not be able to borrow money, sell assets or otherwise raise funds on acceptable terms or at all to refinance our debt as it becomes due. For a further discussion of outstanding debt, see Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations - Financial Condition, Liquidity and Capital Requirements and Note 8 – Debt of Notes to **DPL's** Consolidated Financial Statements and Note 8 – Debt of Notes to **DP&L's** Financial Statements.

DP&L has variable rate debt that bears interest based on a prevailing rate that is reset based on a market index that can be affected by market demand, supply, market interest rates and other market conditions. We also maintain both cash on deposit and investments in cash equivalents from time to time that could be impacted by interest rate fluctuations. As such, any event which impacts market interest rates could have a material effect on our results of operations, financial condition and cash flows. In addition, ratings agencies issue ratings on our credit 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.

Economic conditions relating to the asset performance and interest rates of our pension and postemployment benefit plans could materially and adversely impact our results of operations, financial condition and cash flows.

Pension costs are based upon a number of actuarial assumptions, including an expected long-term rate of return on pension plan assets, level of employer contributions, the expected life span of pension plan beneficiaries and the discount rate used to determine the present value of future pension obligations. Any of these assumptions could prove to be wrong, resulting in a shortfall of our pension and postemployment benefit plan assets compared to obligations under our pension and postemployment benefit plans. Further, 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. We are responsible for funding any shortfall of our pension and postemployment benefit plans' assets compared to obligations under the pension and postemployment benefit plans, and a significant increase in our pension liabilities could materially and adversely impact our results of operations, financial condition, and cash flows. We are subject to the Pension Protection Act of 2006, which 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.

Counterparties providing materials or services may fail to perform their obligations, which could harm our results of operations, financial condition and cash flows.

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. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than relief provided by these mitigation provisions. Any of the foregoing could result in regulatory actions, cost overruns, delays or other losses, any of which (or a combination of which) could have a material adverse effect on our results of operations, financial condition and cash flows.

Further, from time to time our construction program may call for extensive expenditures for capital improvements and additions, including the installation of environmental upgrades, improvements to generation, transmission and distribution facilities, as well as other initiatives. As a result, we may engage contractors and enter into agreements to acquire necessary materials and/or obtain required construction related services. In addition, some contracts may provide for us to assume the risk of price escalation and availability of certain metals and key components. This could force us to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and cause construction delays. It could also subject us to enforcement action by regulatory authorities to the extent that such a contractor failure resulted in a failure by **DP&L** to comply with requirements or expectations, particularly with regard to the cost of the project. As a result of these events, we might incur losses or delays in completing construction.

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

We are subject to extensive laws and local, state and federal regulation, as well as litigation and other proceedings that could affect our operations and costs.
As an electric utility, we are subject to extensive regulation at both the federal and state level. For example, at the federal level, we are regulated by the FERC and the NERC and, at the state level, we are regulated by the PUCO. The regulatory power of the PUCO over **DP&L** is both comprehensive and typical of the traditional form of regulation generally imposed by state public utility commissions. We face the risk of unexpected or adverse regulatory action. Regulatory discretion is reasonably broad in Ohio. We are subject to regulation by the PUCO as to our services and facilities, the valuation of property, the construction, purchase, or lease of electric generating facilities, the classification of accounts, rates of depreciation, the increase or decrease in retail rates and charges, the issuance of securities and incurrence of debt, the acquisition and sale of some public utility properties or securities and certain other matters.

As a result of the Energy Policy Act of 2005 and subsequent legislation affecting the electric utility industry, we have been required to comply with rules and regulations in areas including mandatory reliability standards, cyber security, transmission expansion and energy efficiency. We are currently unable to predict the long-term impact, if any, to our results of operations, financial condition and cash flows as a result of these rules and regulations. Complying with the regulatory environment to which we are subject 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.

We may be subject to material litigation, regulatory proceedings, administrative proceedings, audits, settlements, investigations and claims from time to time which may require us to expend significant funds to address. There can be no assurance that the outcome of these matters will not have a material adverse effect on our business, 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 expected to be 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. Please see Item 1 - Business - Competition and Regulation, Item 1 - Business - Environmental Matters, and Item 3 - Legal Proceedings for a summary of significant regulatory matters and legal proceedings involving us.

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 that could adversely affect our business, results of operations, financial condition and cash flows.
We are subject to collective bargaining agreements with employees who are members of a union. Over half of our employees are represented by a collective bargaining agreement that is in effect until October 31, 2017. 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. We may not be able to successfully train new personnel as current workers with significant knowledge and expertise retire. We also may be unable to staff our business with qualified personnel in the event of significant absenteeism related to a

pandemic illness. Work stoppages by, or poor relations or ineffective negotiations with, our employees or other workforce issues 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 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 with no material assets other than the common stock of its subsidiaries, and accordingly all cash is generated by the operating activities of its subsidiaries, principally **DP&L**. As such, **DPL's** cash flow is largely 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. See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity for a discussion of these restrictions. See Note 8 – Debt of Notes to Notes to **DPL's** Consolidated Financial Statements and Note 7 – Debt of Notes to Notes to **DP&L's** Financial Statements for information regarding indebtedness. 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. The PUCO could impose additional 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.

Our ownership by AES subjects us to potential risks that are beyond our control.
All of **DP&L's** common stock is owned by **DPL**, and **DPL** is a wholly owned subsidiary of AES. Due to our relationship with AES, any adverse developments and announcements concerning them may impair our ability to access the capital markets and to otherwise conduct business. In particular, downgrades in AES's credit ratings could result in **DPL's** or **DP&L's** credit ratings being downgraded.

Impairment of long-lived assets would negatively affect our consolidated results of operations and net worth.
Long-lived assets are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present. The recoverability assessment of long-lived assets requires making estimates and assumptions to determine fair value, as described above. See Note 15 "Fixed-asset Impairment" of Notes to **DPL's** Consolidated Financial Statements and Note 13 "Fixed-asset Impairment" 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 – Business – Electric Operations and Fuel Supply and Note 4 – Property, Plant and Equipment of Notes to **DPL's** Consolidated Financial Statements and Note 4 – Property, Plant and Equipment 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

DPL and **DP&L** are involved in certain claims, suits and legal proceedings in the normal course of business. **DPL** and **DP&L** have accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. **DPL** and **DP&L** believe, based upon information they currently possess and taking into account established reserves for estimated liabilities and insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on their financial statements. It is reasonably possible, however, that some matters could be decided unfavorably and could require **DPL** or **DP&L** to pay damages or make expenditures in amounts that could be material but cannot be estimated as of December 31, 2015.

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.

The following additional information is incorporated by reference into this Item: information about the legal proceedings contained in Item 1 - Business - Competition and Regulation and Item 1 - Business - Environmental Matters.

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 2015, 2014 and 2013, 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 years ended December 31, 2015, 2014 and 2013, **DPL** paid no dividends to AES. During the year ended December 31, 2013, **DPL's** Board of Directors amended the prior 2012 dividend declaration of $70.0 million to be equal to the amount paid, $64.1 million, reversing $5.9 million of the 2012 dividend. **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 $50.0 million, $159.0 million and $190.0 million were declared and paid in the years ended December 31, 2015, 2014 and 2013, 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, 2015, 2014 and 2013.

As of December 31, 2015, **DPL's** leverage ratio was at 1.03 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, as of December 31, 2015, **DPL** was prohibited under its Articles of Incorporation from making a distribution to its shareholder or making a loan to any of its affiliates (other than its subsidiaries).

DPL's secured revolving credit agreement, secured term loan and senior unsecured notes due 2019 include provisions substantially similar to **DPL's** Articles of Incorporation. As a result, as of December 31, 2015, **DPL** was also prohibited under each of these documents from making a distribution to its shareholder or making a loan to any of its affiliates (other than its subsidiaries).

As long as **DP&L** preferred stock is outstanding, **DP&L's** Amended Articles of Incorporation contain provisions which could limit the payment of cash dividends on any of its common stock. Please see Note 10 – Equity of Notes to **DP&L's** Consolidated Financial Statements.

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's** common stock is wholly-owned by an indirect subsidiary of AES and therefore **DPL** 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. The information for **DPL** for 2012 and 2011 is not comparable to the information for 2015, 2014 and 2013 as 2012 and 2011 have not been adjusted to reflect the sale of DPLER and its reclassification as a discontinued operation.

DPL						
	Successor [a]					Predecessor [a]
$ in millions except per share amounts or as indicated	**Year ended December 31, 2015**	Year ended December 31, 2014	Year ended December 31, 2013	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011
Basic earnings per share of common stock [b]	**N/A**	N/A	N/A	N/A	N/A	$ 1.31
Diluted earnings per share of common stock [b]	**N/A**	N/A	N/A	N/A	N/A	$ 1.31
Dividends declared per share of common stock [c]	**N/A**	N/A	N/A	N/A	N/A	$ 1.54
Dividend payout ratio [c]	**N/A**	N/A	N/A	N/A	N/A	117.6%
Total electric sales (millions of kWh)	**14,738**	14,695	15,702	16,454	1,361	15,021
Statements of Operations Data						
Revenues	**$ 1,612.8**	$ 1,716.5	$ 1,579.0	$ 1,668.4	$ 156.9	$ 1,670.9
Goodwill impairment [d]	**$ 317.0**	$ —	$ 306.3	$ 1,817.2	$ —	$ —
Fixed-asset impairment [f]	**$ —**	$ 11.5	$ 26.2	$ —	$ —	$ —
Operating income / (loss)	**$ (109.9)**	$ 230.7	$ (77.4)	$ (1,559.4)	$ 6.1	$ 327.8
Net income / (loss) from continuing operations	**$ (251.4)**	$ 57.2	$ (225.6)	$ (1,729.8)	$ (6.2)	$ 150.5
Net income / (loss) from discontinued operations, net of tax	**$ 12.4**	$ (131.8)	$ 3.6	$ —	$ —	$ —
Net income / (loss) [b]	**$ (239.0)**	$ (74.6)	$ (222.0)	$ (1,729.8)	$ (6.2)	$ 150.5
Total construction additions	**$ 132.0**	$ 116.0	$ 114.0	$ 180.0	$ 201.0	N/A
Balance sheet data (end of period):						
Total assets	**$ 3,340.8**	$ 3,577.8	$ 3,721.5	$ 4,247.3	$ 6,136.2	N/A
Long-term debt [e]	**$ 1,434.5**	$ 2,139.6	$ 2,284.2	$ 2,025.0	$ 2,628.9	N/A
Redeemable preferred stock of subsidiary	**$ 18.4**	$ 18.4	$ 18.4	$ 18.4	$ 18.4	N/A
Total common shareholder's equity	**$ (80.6)**	$ 148.2	$ 239.5	$ 426.8	$ 2,230.7	N/A

DP&L					
$ in millions except per share amounts or as indicated	**Year ended December 31, 2015**	Year ended December 31, 2014	Year ended December 31, 2013	Year ended December 31, 2012	Year ended December 31, 2011
Total electric sales (millions of kWh)	**16,424**	**18,613**	19,423	15,606	15,599
Statements of Operations Data					
Revenues	$ **1,552.3**	$ **1,668.3**	$ 1,551.5	$ 1,531.8	$ 1,677.7
Fixed-asset impairment [(f)]	$ —	$ —	$ 86.0	$ 80.8	$ —
Operating income	**177.8**	188.8	139.9	$ 185.0	$ 319.9
Earnings on common stock [(g)]	$ **105.5**	$ **114.1**	$ 82.7	$ 90.3	$ 192.3
Total construction additions	$ **124.0**	$ 112.0	$ 111.0	$ 177.0	$ 199.0
Balance sheet data (end of period):					
Total assets	$ **3,365.8**	$ 3,338.7	$ 3,313.1	$ 3,464.2	$ 3,538.3
Long-term debt [(e)]	$ **318.0**	$ 877.0	$ 876.9	$ 332.7	$ 903.0
Redeemable preferred stock	$ **22.9**	$ 22.9	$ 22.9	$ 22.9	$ 22.9
Total common shareholder's equity	$ **1,212.7**	$ 1,143.4	$ 1,204.0	$ 1,299.1	$ 1,357.9
Number of shareholders - preferred stock	**180**	**186**	196	209	223

(a) "Predecessor" refers to the operations of **DPL** and its subsidiaries prior to the Merger date. "Successor" refers to the operations of **DPL** and its subsidiaries subsequent to the Merger date.

(b) **DPL** incurred merger-related costs of $37.9 million ($24.6 million net of tax) and $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 impairments of $317.0 million, $306.3 million and $1,817.2 million were recorded in 2015, 2013 and 2012, respectively. The goodwill impairment of $135.8 million in 2014 related to DPLER has been reclassified to discontinued operations.

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

(f) For **DPL**, fixed-asset impairments of $11.5 million ($7.5 million net of tax) and $26.2 million ($17.0 million net of tax) were recorded in 2014 and 2013, respectively. 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) were 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

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 of Terms at the beginning of this Form 10-K.

BUSINESS OVERVIEW

DPL is a regional electric energy and utility company. **DPL** previously had two reporting segments which were the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary. DPLER had a subsidiary, MC Squared that was sold on April 1, 2015. On December 28, 2015, an agreement was signed to sell DPLER. As of December 31, 2015, DPLER met the criteria to be recorded as a Discontinued Operation. As a result, **DPL** now has one reportable segment. See Note 14 – Business Segments of Notes to **DPL's** Consolidated Financial Statements for more information relating to our reportable segment and

Note 16 – Discontinued Operations of Notes to **DPL's** Consolidated Financial Statements. **DP&L** does not have any reportable segments. **DPL** is a wholly-owned subsidiary of AES.

DP&L is primarily engaged in the generation, transmission and distribution of electricity in West Central Ohio and, prior to its sale in January 2016, 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 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.

REGULATORY ENVIRONMENT

For a comprehensive discussion of the market structure and regulation of **DPL** and **DP&L**, see Part I, Item 1 - Business – Competition and Regulation.

DPL, **DP&L** and our subsidiaries' facilities and operations are subject to a wide range of regulatory oversight as well as 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.

Retail Rate Regulation

Ohio law allows retail customers to choose their electric generation supplier and requires an electric distribution utility to provide SSO for any customer that does not choose an alternative generation supplier. The generation and market-based transmission of SSO service is procured through a layering of competitive bid auctions whereby winning bidders are awarded the right and contractual obligation to supply generation service to a portion of the SSO within the utility's service territory over a certain period of time (generally one, two or three years). Winning bidders are awarded a number of tranches (each tranche is equal to 1% of SSO load) based on the lowest bid price in a reverse clock auction. The PUCO oversees the competitive bid and must certify the results each time the bid process is complete.

DP&L's SSO price is set based on the blended combination of the results of the competitive bid auctions, and thus reflects wholesale market prices. **DP&L** bills and collects competitive bid rates from SSO customers and pays the winning bidders based on actual energy supplied. Beginning January 1, 2016, **DP&L's** SSO price will be set based on 100% competitive bid results. Notwithstanding impacts to **DP&L's** wholesale activities, market prices will have less of a direct impact on **DP&L** retail margins in the future since any decrease in market price will result in a decrease of SSO revenues and an offsetting decrease of costs of providing SSO service.

Ohio law allows for pass through of certain costs to retail customers. For example, compliance costs associated with the renewable and energy efficiency laws are recovered through separate riders, or trackers, and are reset on an annual basis. Other costs such as the non-market based transmission and ancillary costs are also passed through in the form of an annual tracker. Costs recovered through a tracker are deferred and carrying costs are applied to any over or under recovered balances. Costs associated with excise tax, low income programs, economic development, storm costs, and other costs may be recovered through a tracker that is trued-up on an annual or periodic basis. The PUCO reviews, audits and must authorize all rate tracker rate changes prior to implementation.

Ohio distribution utilities are permitted to file distribution rate case applications in accordance with the rate making provisions of the Ohio Revised Code and Ohio Administrative Code. **DP&L** filed a distribution rate case on November 30, 2015. See Item 1 - Business – Competition and Regulation for further details.

The costs associated with providing high voltage transmission service and wholesale electric sales and ancillary services are subject to FERC jurisdiction. While **DP&L** has market-based rate authority for wholesale electric sales, **DP&L** would be required to file an application at FERC under section 101 of Title 18 of the Code of Federal Regulations to change any of its cost-based transmission or ancillary service rates.

As directed by the PUCO, **DP&L** filed a corporate separation plan in December 2013 stating its plan to transfer or sell its generation assets. In July 2014, **DP&L** publicly announced its decision not to sell **DP&L's** generation assets at this time, but to maintain its plans to transfer or sell the assets in accordance with PUCO orders by January 1, 2017. The PUCO approved **DP&L's** plan to separate its generation assets with minor modifications.

Ohio Competition

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 procure and provide SSO 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 resulted in increased levels of competition to provide retail generation services. This in turn led to CRES providers, including DPLER, having approximately 72% of 2015 total electric sales in **DP&L's** service territory. DPLER, an affiliated company and one of the registered CRES providers marketing generation services to **DP&L** customers, was sold on January 1, 2016. As discussed in Item 1, beginning January 1, 2016, customer switching will have no effect on **DP&L's** margins. See Item 1A – Risk Factors for more information.

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, 2015, 2014 and 2013:

	Year ended December 31, 2015		**Year ended December 31, 2014**		**Year ended December 31, 2013**	
	Electric Customers	Sales (in millions of kWh)	Electric Customers	Sales (in millions of kWh)	Electric Customers	Sales (in millions of kWh)
Supplied by DPLER	110,739	3,952	131,236	5,649	130,303	5,874
Supplied by non-affiliated CRES providers	128,728	6,019	110,536	4,365	87,951	3,471
Total supplied by CRES providers in **DP&L's** service territory	239,467	9,971	241,772	10,014	218,254	9,345
Distribution customers/sales by **DP&L** in our service territory [(a)]	516,708	13,866	515,622	14,006	514,926	13,877

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

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 wholesale sales requirements for 2016 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 2016. 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.

FINANCIAL OVERVIEW
The results of operations of 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, 2015, 2014 and 2013:

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Revenues	**$ 1,612.8**	$ 1,716.5	$ 1,579.0
Cost of revenues:			
Fuel	**259.8**	304.5	366.7
Purchased power	**562.6**	587.9	383.0
Total cost of revenues	**822.4**	892.4	749.7
Gross margin [(a)]	**790.4**	824.1	829.3
Operating expenses:			
Operation and maintenance	**361.3**	362.4	365.7
Depreciation and amortization	**134.6**	135.6	129.2
General taxes	**87.0**	87.8	76.8
Goodwill impairment	**317.0**	—	306.3
Fixed-asset impairment	**—**	11.5	26.2
Other	**0.4**	(3.9)	2.5
Total operating expenses	**900.3**	593.4	906.7
Operating income / (loss)	**(109.9)**	230.7	(77.4)
Other expense, net			
Investment income	**0.2**	0.9	1.4
Interest expense	**(118.3)**	(126.6)	(124.0)
Charge for early redemption of debt	**(2.1)**	(30.9)	(2.8)
Other deductions	**(1.3)**	(1.5)	(3.0)
Other expense, net	**(121.5)**	(158.1)	(128.4)
Earnings (loss) from continuing operations before income tax	**(231.4)**	72.6	(205.8)
Income tax expense from continuing operations	**$ 20.0**	$ 15.4	$ 19.8
Net income / (loss) from continuing operations	**$ (251.4)**	$ 57.2	$ (225.6)
Discontinued operations (Note 16)			
Income / (loss) from discontinued operations	**$ 11.4**	$ (129.2)	$ 6.0
Income tax expense / (benefit)	**$ (1.0)**	$ 2.6	$ 2.4
Discontinued operations	**$ 12.4**	$ (131.8)	$ 3.6
Net loss	**$ (239.0)**	$ (74.6)	$ (222.0)

(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.

Income Statement Highlights – DPL

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Revenues:			
Retail	$ **785.2**	$ 832.5	$ 780.1
Wholesale	**598.2**	685.0	683.7
RTO revenue	**70.1**	81.9	77.9
RTO capacity revenues	**150.4**	107.9	28.7
Other revenues	**8.8**	9.2	8.9
Mark-to-market gains / (losses)	**0.1**	—	(0.3)
Total revenues	**1,612.8**	1,716.5	1,579.0
Cost of revenues:			
Cost of Fuel:			
Fuel	**263.1**	305.4	366.0
Losses / (gains) from sale of coal	**(3.0)**	(1.3)	0.7
Mark-to-market losses / (gains)	**(0.3)**	0.4	—
Net fuel cost	**259.8**	304.5	366.7
Purchased power:			
Purchased power	**336.1**	323.7	236.5
RTO charges	**97.9**	154.2	111.9
RTO capacity charges	**122.5**	107.5	34.0
Mark-to-market losses	**6.1**	2.5	0.6
Net purchased power	**562.6**	587.9	383.0
Total cost of revenues	**822.4**	892.4	749.7
Gross margins [(a)]	$ **790.4**	$ 824.1	$ 829.3
Gross margins as % of revenue	**49%**	48%	53%
Operating income / (loss)	$ **(109.9)**	$ 230.7	$ (77.4)

(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.

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,		
	2015	2014	2013
Heating degree days [(a)]	**5,163**	5,950	5,542
Cooling degree days [(a)]	**1,060**	977	1,062

(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 have historically utilized our internal generating capacity to supply the needs of our retail customers within the **DP&L** service territory first, increases in on-system retail demand may have decreased the volume of internal generation available to be sold in the wholesale market and vice versa. Beginning in 2016, **DP&L** retail demand is sourced 100% through a competitive auction. 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 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	**2015 vs. 2014**	2014 vs. 2013
Retail		
Rate	$ **(28.7)**	$ 108.4
Volume	**(13.0)**	(55.7)
Other	**(5.6)**	(0.3)
Total retail change	**(47.3)**	52.4
Wholesale		
Rate	**4.1**	11.3
Volume	**(90.9)**	(10.0)
Total wholesale change	**(86.8)**	1.3
RTO capacity and other		
RTO capacity and other	**30.7**	83.2
Other		
Other	**(0.3)**	0.6
Total revenue changes	$ **(103.7)**	$ 137.5

During the year ended December 31, 2015, Revenues decreased $103.7 million, or 6%, to $1,612.8 million from $1,716.5 million in the same period of the prior year. This decrease was primarily the result of lower wholesale sales, lower average retail rates and lower retail volume, partially offset by increased RTO capacity and other revenues.

- Retail revenues decreased $47.3 million primarily due to lower retail prices driven by decreased retail revenue for SSO customers as the competitive auction rate, which represents 60% of **DP&L** SSO load in 2015 as compared to 10% in 2014, is lower than our non-auction generation rate, a decrease in the USF program recovery rate in 2015, and higher recovery of transmission costs in the prior year. These decreases were partially offset by a price increase driven by recovery of deferred storm costs in 2015. Sales volume also decreased due to milder winter weather in 2015. The aforementioned impacts resulted in an unfavorable $28.7 million retail price variance and an unfavorable $13.0 million retail volume variance.
- Wholesale revenues decreased $86.8 million primarily as a result of an unfavorable $90.9 million wholesale volume variance and a favorable $4.1 million wholesale price variance. Although **DP&L** had excess generation available to be sold in the wholesale market in 2015 resulting from 60% of its SSO load being

served through the competitive bid process compared to 10% during 2014, there was also a 17% decrease in net generation from **DP&L's** co-owned and operated plants due to the 2014 sale of East Bend, the closing of Beckjord and increased outages. **DPL** also had decreased full requirements sales to DPLER, as a result of the sale of MC Squared and decreased customers at DPLER in 2015 compared to 2014. These sales were previously eliminated in consolidation prior to DPLER becoming a discontinued operation. The price increase of $4.1 million was due to higher prices on sales to DPLER, partially offset by lower market prices.

- 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, increased $30.7 million compared to the prior year. This increase was primarily the result of a $42.5 million increase in revenue realized from the PJM capacity auction. The capacity prices that became effective in June of 2015 were $136/MW/day, compared to $126/MW/day in June 2014 and $28/MW/day in June 2013. This increase was offset by an $11.8 million decrease in RTO transmission and congestion revenue, as 2014 congestion revenue charges were higher due to extreme weather.

During the year ended December 31, 2014, Revenues increased $137.5 million, or 9%, to $1,716.5 million from $1,579.0 million in the same period of the prior year. This increase was primarily the result of higher average retail rates and increased RTO capacity revenues; partially offset by lower retail and wholesale sales volume.

- Retail revenues increased $52.4 million primarily due to a 9.5% increase in average retail rates which resulted from the PUCO approved service stability rider and recovery of various costs through regulatory riders. **DP&L** sales volume also decreased by 7.4% from the prior year due to customer switching. The above resulted in a favorable $108.4 million retail price variance and an unfavorable $55.7 million retail volume variance.
- Wholesale revenues only increased $1.3 million, or 0.2%, due to an $11.3 million favorable wholesale price variance, partially offset by a $10.0 million unfavorable wholesale volume variance. Although customer switching in the **DP&L** service territory resulted in increased generation available to sell in the wholesale market, there was a 13% decrease in net generation available from **DP&L's** co-owned and operated generation plants due to higher outages which resulted in the decrease in wholesale sales volume. The price increase of $11.3 million was due to higher prices on sales to DPLER, partially offset by lower market prices.
- 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, increased $83.2 million. This increase was primarily a result of a $79.2 million increase in revenues realized from the PJM capacity auction and an increase of $4.0 million in RTO transmission and congestion revenues.

DPL – Cost of Revenues

During the year ended December 31, 2015, Total cost of revenues decreased $70.0 million, or 8% compared to the prior year. This decrease was a result of:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $44.7 million, or 15%, compared to the prior year primarily due to a 16% decrease in internal generation as a result of increased outages and plant closures or sales, partially offset by a 2.4% increase in average fuel cost per MWh.
- Net purchased power decreased $25.3 million, or 4%, compared to the prior year. This decrease was driven by the following factors:
    - Purchased power increased $12.4 million, or 4%, primarily due to a $23.9 million increase as a result of a 6.5% increase in average purchased power price, and also due to increased purchases for our SSO load through the competitive bid process. These increases were partially offset by an $11.5 million volume decrease driven by decreased power purchased to source DPLER customers throughout 2015 due to the sale of MC Squared along with customer switching. The price increase above also includes a partial offset resulting from a $10 million regulatory deferral of OVEC costs that are probable for future recovery. We purchase power for our SSO load sourced through the competitive bid process and to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages, when market prices are below the marginal costs associated with our generating facilities, or to meet high customer demand.

- RTO charges decreased $56.3 million, or 37%, as a result of higher transmission and congestion charges incurred in 2014 as well as decreased load obligations as a result of increased SSO sales being sourced through the competitive auction. RTO charges are incurred as a member of PJM and include costs associated with **DP&L's** load obligations.
- RTO capacity charges increased $15.0 million, or 14%, driven by a $7.3 million PJM penalty associated with low plant availability in 2015 compared to an approximate $2.4 million penalty recorded in 2014 and higher RTO capacity prices, partially offset by decreased load obligations for retail customers in 2015. As noted above, RTO capacity prices are set by an annual auction.
- Mark-to-market losses increased $3.6 million.

During the year ended December 31, 2014, Total cost of revenues increased $142.7 million, or 19% compared to the prior year. This increase was a result of:

- Net fuel costs decreased $62.2 million, or 17%, compared to the prior year, primarily due to a 13% decrease in internal generation as a result of increased outages combined with lower average fuel prices.
- Net purchased power increased $204.9 million, or 53%, compared to the prior year. This increase was driven by the following factors:
    - Purchased power increased $87.2 million, or 37%, due to increased volume of $58.6 million and $28.6 million due to higher average market prices for purchased power. We purchase power for our SSO load sourced through the competitive bid process and to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages, when market prices are below the marginal costs associated with our generating facilities, or to meet high customer demand.
    - RTO charges increased $42.3 million, or 38%, as a result of higher transmission and congestion charges incurred in 2014 due to extreme weather. RTO charges are incurred as a member of PJM and include costs associated with **DP&L's** load obligations for retail customers.
    - RTO capacity charges increased $73.5 million due to higher RTO capacity prices. RTO capacity prices are set by an annual auction.
    - Mark-to-market losses increased $1.9 million.

DPL - Operation and Maintenance

$ in millions		2015 vs. 2014
Low-income payment program [(a)]	$	(20.1)
Deferred storm costs [(a)]		17.5
Alternative energy and energy efficiency programs [(a)]		3.9
Other, net		(2.4)
Total operation and maintenance expense	$	(1.1)

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

During the year ended December 31, 2015, Operation and maintenance expense decreased $1.1 million compared to the prior year. This variance was primarily the result of:

- decreased expenses for the low-income payment program which are funded by the USF revenue rate rider.

These decreases were partially offset by:

- increased storm costs, which were previously deferred but were recognized as they were recovered through customer rates in 2015; and
- increased expenses related to alternative energy and energy efficiency programs.

$ in millions		2014 vs. 2013
Low-income payment program [(a)]	$	(10.1)
Health insurance and disability		(4.3)
Deferred compensation liability		(1.5)
Generating facilities operating and maintenance expenses		2.8
Maintenance of overhead transmission and distribution facilities		5.3
Alternative energy and energy efficiency programs [(a)]		2.7
Other, net		1.8
Total operation and maintenance expense	$	(3.3)

(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, 2014, Operation and maintenance expense decreased $3.3 million, or 1%, compared to the prior year. This variance was primarily the result of:

- decreased expenses for the low-income payment program which are funded by the USF revenue rate rider;
- decreased health insurance due to cost decreases as well as a reduction in the disability reserve as a result of the 2014 actuarial study; and
- decreased deferred compensation costs.

These decreases were partially offset by:

- increased maintenance expenses at our generation facilities;
- increased expenses related to the maintenance of overhead transmission and distribution lines; and
- increased expenses related to alternative energy and energy efficiency programs.

DPL – Depreciation and Amortization

During the year ended December 31, 2015, Depreciation and amortization expense decreased $1.0 million, or 1%, compared to the prior year. The decrease is primarily due to the sale of East Bend and the retirement of Beckjord, partially offset by increased depreciation associated with increased ARO assets and net plant additions.

During the year ended December 31, 2014, Depreciation and amortization expense increased $6.4 million, or 5%, compared to the prior year. The increase primarily reflects additional investments in fixed assets.

DPL – General Taxes

During the year ended December 31, 2015, General taxes changed an immaterial amount compared to the prior year.

During the year ended December 31, 2014, General taxes increased $11.0 million, or 14%, compared to the prior year. This increase was primarily due to an adjustment to the 2013 estimated property tax liability to adjust estimates to actual payments that were made in 2014, higher property tax accruals for 2014 compared to 2013 and a favorable determination of $1.6 million from the Ohio gross receipts appeal in 2013.

DPL – Goodwill Impairment

During the year ended December 31, 2015, **DPL** recorded an impairment of goodwill of $317.0 million compared to $0.0 million the prior year. Our goodwill impairment test indicated that the fair value of the DP&L Reporting Unit was less than its carrying amount, primarily due to a decrease in dark spreads that were driven by decreases in forward power prices, and lower revenues from the new CP product. See Note 7 – Goodwill and Other Intangible Assets of Notes to **DPL's** Consolidated Financial Statements.

The goodwill impairment in 2014 has been reclassified to Discontinued operations. See Note 16 – Discontinued Operations of Notes to **DPL's** Consolidated Financial Statements

DPL – Fixed Asset Impairment

During the year ended December 31, 2014, **DPL** recorded an impairment of fixed-assets of $11.5 million related to **DP&L's** East Bend facility, which was sold in 2014. See Note 15 – Fixed-asset Impairment of Notes to **DPL's** Consolidated financial Statements.

DPL – Interest Expense

During the year ended December 31, 2015, Interest expense decreased $8.3 million, or 7%, compared to the prior year due primarily to a reduction of debt at **DP&L** and **DPL**, as well as decreased interest rates on **DP&L's** senior secured pollution control bonds, partially offset by increased carrying costs on regulatory assets.

During the year ended December 31, 2014, Interest expense increased $2.6 million, or 2%, compared to the prior year due primarily to reduced amortization of debt premium (which increases interest expense) partially offset by decreased interest due to reductions in debt at **DPL** and decreased full year effective interest rates on **DP&L's** senior secured first mortgage bonds.

DPL – Income Tax Expense

During the year ended December 31, 2015, Income tax expense increased $4.6 million compared to the prior year primarily due to higher pre-tax income (excluding the effect of the 2015 goodwill impairment). This increase was partially offset by an anticipated refund from the IRS for the filing of an amended 2011 predecessor tax return, a deferred tax adjustment related to the expiration of the statute of limitations in 2014 that did not occur in 2015 and an increase in the tax benefits of Internal Revenue Code Section 199 in 2015.

During the year ended December 31, 2014, Income tax expense decreased $4.4 million compared to the prior year primarily due to lower pre-tax income (excluding the effect of the 2013 goodwill impairment), a 2014 deferred tax adjustment related to the expiration of the statute of limitations on the 2010 tax year and a decrease in the tax benefits of Internal Revenue Code Section 199 in 2014.

Discontinued Operations

Total discontinued operations included net income of $12.4 million, net loss of $131.8 million, and net income of $3.6 million for the years ended December 31, 2015, 2014 and 2013, respectively. See Note 16 – Discontinued Operations in Notes to **DPL's** Consolidated Financial Statements.

RESULTS OF OPERATIONS – Utility Segment (DP&L)

Income Statement Highlights – DP&L

$ in millions	Years ended December 31, 2015	2014	2013
Revenues:			
Retail	**$ 786.7**	$ 834.2	$ 782.0
Wholesale	**576.2**	666.0	671.3
RTO revenues	**65.7**	77.6	74.5
RTO capacity revenues	**123.6**	90.5	24.0
Mark-to-market gains / (losses)	**0.1**	—	(0.3)
Total revenues	**1,552.3**	1,668.3	1,551.5
Cost of revenues:			
Cost of fuel:			
Fuel	**248.0**	315.8	361.8
Losses / (gains) from sale of coal	**(3.1)**	(1.3)	0.7
Mark-to-market (gains) / losses	**(0.2)**	0.4	—
Net fuel costs	**244.7**	314.9	362.5
Purchased power:			
Purchased power	**336.5**	322.9	237.6
RTO charges	**94.1**	150.4	109.8
RTO capacity charges	**119.1**	106.7	33.9
Mark-to-market losses	**6.0**	2.4	0.6
Net purchased power	**555.7**	582.4	381.9
Total cost of revenues	**800.4**	897.3	744.4
Gross margins [(a)]	**$ 751.9**	$ 771.0	$ 807.1
Gross margins as a % of revenues	**48%**	46%	52%
Operating income	**$ 177.8**	$ 188.8	$ 139.9

(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:

$ in millions	**2015 vs. 2014**	2014 vs. 2013
Retail		
Rate	$ **(28.7)**	$ 108.4
Volume	**(13.0)**	(55.7)
Other	**(5.8)**	(0.5)
Total retail change	**(47.5)**	52.2
Wholesale		
Rate	**5.8**	6.6
Volume	**(95.6)**	(11.9)
Total wholesale change	**(89.8)**	(5.3)
RTO capacity and other		
RTO capacity and other revenues	**21.2**	69.6
Other		
Unrealized MTM	**0.1**	0.3
Total revenues change	$ **(116.0)**	$ 116.8

During the year ended December 31, 2015, Revenues decreased $116.0 million, or 7%, to $1,552.3 million from $1,668.3 million in the prior year. This decrease was primarily the result of lower retail rates and volume, and lower wholesales volume; partially offset by higher RTO capacity and other revenues.

- Retail revenues decreased $47.5 million primarily due to lower retail prices driven by decreased retail revenue for SSO customers as the competitive auction rate, which represents 60% of our SSO load in 2015 as compared to 10% in 2014, is lower than our non-auction generation rate, a decrease in the USF program recovery rate in 2015, and higher recovery of transmission costs in the prior year. These decreases were partially offset by a price increase driven by recovery of deferred storm costs in 2015. Further, heating degree days decreased by 787, or 13%, while cooling degree days increased by 83, or 8.5%, compared to 2014, which contributed to a volume decrease. The above resulted in an unfavorable $28.7 million retail price variance and an unfavorable $13.0 million retail volume variance.

- Wholesale revenues decreased $89.8 million as a result of an unfavorable $95.6 million wholesale volume variance and a favorable $5.8 million wholesale price variance. Although **DP&L** had excess generation available to be sold in the wholesale market in 2015 resulting from 60% of its SSO load being served through the competitive bid process compared to 10% during 2014, there was a 17% decrease in net generation from **DP&L's** co-owned and operated plants due to the 2014 sale of East Bend, the closing of Beckjord and increased unplanned outages. **DP&L** also had decreased full requirements sales to DPLER, as a result of the sale of MC Squared and decreased customers at DPLER in 2015 compared to 2014. The price increase was due to higher prices on sales to DPLER, partially offset by lower market prices.

- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, as well as capacity revenues under the RPM construct, increased $21.2 million. This increase was primarily the result of a $33.1 million increase in revenue realized from the PJM capacity auction. The capacity prices that became effective in June of 2015 were $136/MW/day, compared to $126/MW/day in June 2014 and $28/MW/day in June 2013. This increase was offset by an $11.9 million decrease in RTO transmission and congestion revenue, as 2014 congestion revenue charges were higher due to extreme weather.

During the year ended December 31, 2014, Revenues increased $116.8 million, or 8%, to $1,668.3 million from $1,551.5 million in the prior year. This increase was primarily the result of higher average retail rates and increased RTO capacity revenues; partially offset by lower retail and wholesale volume.

- Retail revenues increased $52.2 million due to a 15% increase in average retail rates which resulted from the PUCO approved service stability rider and recovery of various costs through regulatory riders. Retail volume decreased 7.4% overall due to a 26% increase in the percentage of volume in the **DP&L** service territory being supplied by the third-party CRES providers. **DP&L** continues to provide distribution services to these customers but volumes are not recorded. Heating degree days increased by 408, or 7%, while cooling degree days decreased by 85, or 8%, compared to 2013. During 2014, 31% of **DP&L's** distribution sales were supplied by third-party CRES providers. As we only have distribution revenue on these sales, the weather impact is less than the weather impact on SSO sales. The above resulted in a favorable $108.4 million retail price variance and an unfavorable $55.7 million retail volume variance

- Wholesale revenues decreased $5.3 million as a result of an $11.9 million decrease in wholesale sales volume, partially offset by a favorable $6.6 million price variance. Although customer switching in the **DP&L** service territory resulted in increased generation available to sell in the wholesale market, there was a 13% decrease in net generation available from **DP&L's** co-owned and operated generation plants due to higher outages which resulted in an overall decrease in wholesale sales volume.
- 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, increased $69.6 million. This increase was primarily the result of a $66.5 million increase in revenues realized from the PJM capacity market auction and an increase of $3.1 million in RTO transmission and congestion revenues.

DP&L – Cost of Revenues

During the year ended December 31, 2015 total cost of revenues decreased $96.9 million, or 11%, compared to the prior year. This decrease was primarily due to:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $70.2 million, or 22%, driven by a 17% decrease in internal generation at our plants combined with lower average fuel prices.
- Net purchased power decreased $26.7 million, or 5%, compared to the prior year. This decrease was driven by the following factors:
    - Purchased power increased $13.6 million, or 4%, primarily due to a $24.3 million price increase, partially offset by a $10.7 million volume decrease. We purchase power for our SSO load sourced through the competitive bid process and to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages, when market prices are below the marginal costs associated with our generating facilities, or to meet high customer demand. The increase above includes a partial offset resulting from a $10 million regulatory deferral of OVEC costs that are probable for future recovery.
    - RTO charges decreased $56.3 million, or 37%, as a result of higher transmission and congestion charges incurred in 2014 due to severe weather and decreased load obligations is 2015. RTO charges are incurred as a member of PJM and include costs associated with **DP&L's** load obligations for retail customers.
    - RTO capacity and other costs increased $12.4 million, or 12%, driven by a $7.3 million PJM penalty associated with low plant availability in 2015 and higher RTO capacity prices, partially offset by decreased load obligations for retail customers in 2015. As noted above, RTO capacity prices are set by an annual auction.
    - Mark-to-market losses increased $3.6 million.

During the year ended December 31, 2014 total cost of revenues increased $152.9 million, or 21%, compared to the prior year. This increase was primarily due to:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $47.6 million, or 13% primarily due to a 13% decrease in internal generation due to increased outages combined with lower average fuel prices, partially offset by costs associated with the early termination of a fuel contract.
- Net purchased power increased $200.5 million, or 53% compared to the prior year. This increase was driven by the following factors:
    - Purchased power costs increased $85.3 million, primarily due to a volume increase of 21% as a result of increased outages at our generating stations during 2014 and average purchased power prices increased 12%. We purchase power for our SSO load sourced through the competitive bid process and to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages, when market prices are below the marginal costs associated with our generating facilities, or to meet high customer demand.

  - RTO charges increased $40.6 million, or 37%, as a result of higher transmission and congestion charges incurred in 2014 due to severe weather. RTO charges are incurred as a member of PJM and include costs associated with **DP&L's** load obligations for retail customers.
  - RTO capacity and other costs increased $72.8 million driven by higher RTO capacity prices. As noted above, RTO capacity prices are set by an annual auction.
  - Mark-to-market losses increased $1.8 million.

DP&L – Operation and Maintenance

$ in millions		2015 vs. 2014
Low-income payment program [(a)]	$	(20.1)
Generating facilities operating and maintenance expenses		(5.7)
Deferred storm costs [(a)]		17.5
Alternative energy and maintenance expense [(a)]		3.9
Other, net		(0.3)
Total operation and maintenance expense	$	(4.7)

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

During the year ended December 31, 2015, Operation and maintenance expense decreased $4.7 million, or 1%, compared to the prior year. This variance was primarily the result of:

- decreased expenses for the low-income payment program which is funded by the USF revenue rate rider; and
- decreased maintenance expenses at our generating facilities.

These decreases were partially offset by:

- increased storm costs, which were previously deferred but were recognized as they were recovered through customer rates in 2015; and
- increased expenses related to alternative energy and energy efficiency programs.

$ in millions		2014 vs. 2013
Low-income payment program [(a)]	$	(10.1)
Health Insurance and disability		(4.7)
Pension		(1.5)
Deferred compensation liability		(1.5)
Generating facilities operating and maintenance expenses		5.7
Maintenance of overhead transmission and distribution		5.2
Alternative energy and energy efficiency programs [(a)]		1.6
Other, net		(3.7)
Total operation and maintenance expense	$	(9.0)

(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, 2014, Operation and maintenance expense decreased $9.0 million, or 2%, compared to the prior year. This variance was primarily the result of:

- decreased expenses for the low-income payment program which is funded by the USF revenue rate rider;
- decreased health insurance due to cost decreases as well as a reduction in the disability reserve as a result of the 2014 actuarial study;
- lower pension expenses primarily related to changes in plan assumptions, specifically a higher discount rate; and
- decreased deferred compensation costs.

These decreases were partially offset by:

- increased maintenance expenses at our generating facilities;
- increased expenses related to the maintenance of overhead transmission and distribution lines; and
- increased expenses relating to alternative energy and energy efficiency programs.

DP&L – Depreciation and Amortization

During the year ended December 31, 2015, Depreciation and amortization expense decreased $6.6 million, or 5%, compared to the prior year. The decrease is primarily due to the sale of the East Bend Plant and the retirement of the Beckjord Plant, partially offset by increased depreciation associated with increased ARO assets and net plant additions.

During the year ended December 31, 2014, Depreciation and amortization expense increased $4.6 million, or 3%, compared to the prior year. The increase primarily reflects additional investments in fixed assets.

DP&L – General Taxes

During the year ended December 31, 2015, General taxes changed an immaterial amount compared to the prior year.

During the year ended December 31, 2014, General taxes increased $11.4 million, or 15%, compared to the prior year. This increase was primarily due to an adjustment to the 2013 estimated property tax liability to adjust estimates to actual payments that were made in 2014, higher property tax accruals for 2014 compared to 2013 and a favorable determination of $1.6 million from the Ohio gross receipts tax appeal in 2013.

DP&L – Fixed-asset Impairment and gain on asset sale

During the year ended December 31, 2015, **DP&L** did not have any fixed-asset impairment or significant gains on asset sales.

During the year ended December 31, 2014, **DP&L** recorded a gain of $4.5 million on the sale of its interest in the East Bend generating station. See Note 13 – Fixed-asset Impairment of Notes to **DP&L's** Financial Statements for more information on the impairment.

DP&L – Interest Expense

During the year ended December 31, 2015, interest expense decreased $3.0 million, or 9%, compared to the prior year due to a reduction in outstanding debt and lower interest rates on **DP&L's** senior secured bonds.

During the year ended December 31, 2014, interest expense decreased $3.3 million, or 9%, compared to the prior year due to a reduction in outstanding debt and lower interest rates on **DP&L's** senior secured bonds.

DP&L – Income Tax Expense

During the year ended December 31, 2015, Income tax expense decreased $4.6 million compared to the prior year primarily due to decreases in pre-tax income, an anticipated refund from the IRS for the filing of an amended 2011 predecessor tax return and an increase in the tax benefits of Internal Revenue Code Section 199 in 2015. Partially offsetting the decrease is a deferred tax adjustment related to the prior year expiration of the statute of limitations that did not occur in 2015.

During the year ended December 31, 2014, Income tax expense increased $21.1 million compared to the prior year primarily due to increases in pre-tax income, a 2014 deferred tax adjustment related to the expiration of the statute of limitations on the 2010 tax year and a decrease in the tax benefits of Internal Revenue Code Section 199 in 2014.

CAPITAL RESOURCES AND LIQUIDITY

Cash and cash equivalents for **DPL** and **DP&L** was $32.4 million and $5.4 million, respectively, at December 31, 2015. At that date, neither **DPL** nor **DP&L** had short-term investments. **DPL** and **DP&L** had aggregate principal amounts of debt outstanding of $2,013.7 million and $763.1 million, respectively.

Approximately $574.9 million of **DPL's** debt matures within the next twelve months, which we expect to repay using a combination of cash on hand, net cash provided by operating activities and/or net proceeds from the issuance of new debt.

Given our long-term debt obligations, we are subject to interest rate risk on debt balances that accrue interest at variable rates. When prudent, we will borrow funds at fixed interest rates or hedge its variable rate debt to fix its interest costs on such obligations.

We depend on timely and continued access to capital markets to manage our liquidity needs. The inability to raise capital on favorable terms, to refinance existing indebtedness or to fund operations and other commitments during times of political or economic uncertainty may have material adverse effects on our financial condition and results of operations. In addition, changes in the timing of tariff increases or delays in the regulatory determinations could affect the cash flows and results of operations of our business.

CASH FLOWS

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 tables provide summaries of the cash flows for **DPL** and **DP&L**:

DPL	Years ended December 31,		
$ in millions	**2015**	2014	2013
Net cash from operating activities	**$ 308.5**	$ 244.1	$ 302.8
Net cash from investing activities	**(136.7)**	(112.6)	(123.9)
Net cash from financing activities	**(156.4)**	(167.7)	(317.8)
Net increase / (decrease) in cash	**15.4**	(36.2)	(138.9)
Balance at beginning of period	**17.0**	53.2	192.1
Cash and cash equivalents at end of period	**$ 32.4**	$ 17.0	$ 53.2

DP&L	Years ended December 31,		
$ in millions	**2015**	2014	2013
Net cash from operating activities	**$ 256.7**	$ 251.7	$ 335.3
Net cash from investing activities	**(122.5)**	(108.5)	(114.5)
Net cash from financing activities	**(134.2)**	(160.7)	(226.4)
Net increase / (decrease) in cash	**—**	(17.5)	(5.6)
Balance at beginning of period	**5.4**	22.9	28.5
Cash and cash equivalents at end of period	**$ 5.4**	$ 5.4	$ 22.9

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

DPL – Net cash from operating activities

During the year ended December 31, 2015, Net cash from operating activities was primarily a result of Net loss adjusted for depreciation and amortization, the impairment of goodwill, deferred income taxes, and other non-cash adjustments, as well as collections of accounts receivable and collections of deferred regulatory costs.

During the year ended December 31, 2014, Net cash from operating activities was primarily a result of Net loss adjusted for depreciation and amortization, the impairment of goodwill and fixed-assets, deferred income taxes, a charge for the early redemption of debt, and other non-cash adjustments.

During the year ended December 31, 2013, Net cash from operating activities was primarily a result of Net loss adjusted for depreciation and amortization, the impairment of goodwill and fixed-assets and deferred income taxes.

DP&L – Net cash from operating activities

During the year ended December 31, 2015, the significant components of **DP&L's** Net cash from operating activities were primarily the result of Net income adjusted for depreciation and amortization.

During the year ended December 31, 2014, the significant components of **DP&L's** Net cash from operating activities were primarily the result of Net income adjusted for depreciation and amortization.

During the year ended December 31, 2013, the significant components of **DP&L's** Net cash from operating activities were primarily a result of Net income adjusted for depreciation and amortization, as well as a non-cash charge related to the impairment of certain generation facilities.

DPL – Net cash from investing activities

During the year ended December 31, 2015, **DPL's** cash from investing activities was primarily related to capital expenditures, partially offset by proceeds from the sale of property.

During the year ended December 31, 2014, **DPL's** cash from investing activities was primarily related to capital expenditures, partially offset by proceeds from the sale of property.

During the year ended December 31, 2013, **DPL's** cash from investing activities was primarily related to capital expenditures.

DP&L – Net cash from investing activities

During the year ended December 31, 2015, **DP&L's** cash from investing activities was primarily related to capital expenditures, partially offset by insurance proceeds.

During the year ended December 31, 2014, **DP&L's** cash from investing activities was primarily related to capital expenditures, partially offset by proceeds from the sale of property.

During the year ended December 31, 2013, **DP&L's** cash from investing activities was primarily related to capital expenditures. 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.

DPL – Net cash from financing activities

During the year ended December 31, 2015, **DPL's** Net cash from financing activities primarily relates to the retirement of $474.5 million of debt, partially offset by a $325.0 million issuance of new debt.

During the year ended December 31, 2014, **DPL's** Net cash used for financing activities primarily relates to the redemption of $335.0 million of debt and associated redemption premiums, partially offset by a $200.0 million issuance of new debt.

During the year ended December 31, 2013, **DPL's** Net cash from financing activities primarily relates to the payment at maturity of $470.0 million of **DP&L's** senior secured bonds, early redemption of $475.1 million of debt and debt issuance costs, partially offset by the issuance of $445.0 million of new senior secured bonds and the issuance of $200.0 million of new debt.

DP&L – Net cash from financing activities

During the year ended December 31, 2015, **DP&L's** Net cash from financing activities primarily relates to the retirement of $314.5 million of long-term debt, partially offset by the issuance of $200.0 million of new debt.

During the year ended December 31, 2014, **DP&L's** Net cash from financing activities primarily relates to $159.0 million in dividends.

During the year ended December 31, 2013, **DP&L's** Net cash from financing activities primarily relates to $190.0 million in dividends and the issuance of $445.0 million of senior secured bonds, the proceeds of which were used to redeem **DP&L's** senior secured bonds at maturity.

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 2016 and subsequent years, we expect to satisfy these requirements with a combination of cash from operations and funds from 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, 2015
DPL	Revolving	July 2020	205.0	202.0
DP&L	Revolving	July 2020	$ 175.0	$ 173.6
			$ 380.0	$ 375.6

DP&L has an unsecured revolving credit agreement with a syndicated bank group. Prior to refinancing the facility on July 31, 2015, as discussed below, this facility had a $300.0 million borrowing limit, a five-year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature that provided **DP&L** the ability to increase the size of the facility by an additional $100.0 million.

On July 31, 2015, **DP&L** refinanced its revolving credit facility, reducing the total size from $300.0 million to $175.0 million, with a $50.0 million letter of credit sublimit and a feature that provides **DP&L** the ability to increase the size of the facility by an additional $100.0 million, and extending the term of the facility from May 2018 to July 2020. At December 31, 2015, **DP&L** had no draws under this facility and had two letters of credit in the aggregate amount of $1.4 million outstanding, with the remaining $173.6 million available to **DP&L**. Fees associated with this facility were not material during the years ended December 31, 2015 or 2014.

DPL has a revolving credit facility. This facility has a letter of credit sublimit and a feature that provides **DPL** the ability to increase the size of the facility. Prior to refinancing the facility on July 31, 2015, as discussed below, this facility was unsecured and had a borrowing limit of $100.0 million with a $100.0 million letter of credit sublimit, was able to be increased in size by **DPL** by an additional $50.0 million, and had a five year term expiring on May 10, 2018; with a springing maturity, meaning that if **DPL** had not refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then the maturity of this facility would have been July 15, 2016.

On July 31, 2015, **DPL** refinanced its revolving credit facility, increasing the total size from $100.0 million to $205.0 million, with a $200.0 million letter of credit sublimit and a feature that provides **DPL** the ability to increase the size of the facility by an additional $95.0 million This facility is secured by a pledge of common stock that **DPL** owns in **DP&L**, limited to the amount permitted to be pledged under certain Indentures dated October 3, 2011 and October 6, 2014 between **DPL** and Wells Fargo Bank, NA and U.S. Bank National Association, respectively, as Trustee and a limited recourse guarantee by DPLE secured by mortgages on assets of DPLE. The refinancing extended the life of the facility from May 2018 to July 2020. **DPL's** new credit facility has a springing maturity feature, replacing the previous springing maturity feature, providing that if, before July 1, 2019, **DPL** has not refinanced its senior unsecured bonds due October 2019 to have a maturity date that is at least six months later than July 31, 2020, then the maturity of this facility shall be July 1, 2019.

Capital Requirements

Construction Additions

	Actual			Projected		
$ in millions	2013	2014	2015	2016	2017	2018
DPL	$ 114	$ 116	$ 132	$ 150	$ 151	$ 138
DP&L	$ 111	$ 112	$ 124	$ 134	$ 86	$ 86

Planned construction additions for 2016 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. As discussed previously, **DP&L** must separate its generation assets by January 1, 2017. Accordingly, estimated capital expenditures related to the generation assets of $104.0 million are not included in **DP&L's** estimated spending for 2017 and 2018 in the table above. Those estimated costs are included in the **DPL** amounts.

DPL, primarily through its subsidiary **DP&L**, is projecting to spend an estimated $439.0 million in capital projects for the period 2016 through 2018. **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 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 $6.7 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

The **DPL** revolving credit facility and term loan agreement 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 agreements is not to exceed 7.25 to 1.00 for any fiscal quarter ending September 30, 2015 through December 31, 2018; it then steps down to not exceed 6.25 to 1.00 for any fiscal quarter ending March 31, 2019 through December 31, 2019; and it then steps down not to exceed 5.75 to 1.00 for any fiscal quarter ending March 31, 2020 through July 31, 2020. As of December 31, 2015, this financial covenant was met with a ratio of 5.71 to 1.00.

The **DPL** revolving credit facility and term loan agreement also 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 agreements, is to be not less than 2.10 to 1.00 for any fiscal quarter ending September 30, 2015 through December 31, 2018; it then steps up to be not less than 2.25 to 1.00 for any fiscal quarter ending March 31, 2019 through July 31, 2020. As of December 31, 2015, this financial covenant was met with a ratio of 3.04 to 1.00.

DP&L's revolving credit facility and Bond Purchase and Covenants Agreement (financing document entered into in connection with the sale of the new $200 million of variable rate pollution control bonds, dated as of August 1, 2015, containing representations, warranties, covenants and defaults consistent with those contained in the revolving credit facilities loan documents of **DP&L**) have two financial covenants. First, prior to the date of completion of the separation of **DP&L's** generation assets from its transmission and distribution assets, **DP&L's** Total Debt to Total Capitalization may not be greater than 0.65 to 1.00 at any time; and, on and after the date of completion of the separation of **DP&L's** generation assets from its transmission and distribution assets, **DP&L's** Total debt to Total Capitalization may not be greater than 0.75 to 1.00 at any time, except that required compliance with this financial covenant shall be suspended if **DP&L** maintains a rating of BBB- (or in the case of Moody's Baa3) or higher with a stable outlook from at least one of Fitch Investors Service Inc., Standard & Poor's Ratings Services or Moody's Investors Service, Inc., as determined in accordance with the terms of the revolving credit facility. This covenant shall be suspended between January 1, 2017 and December 31, 2017, if during this same time, **DP&L's** long-term indebtedness (as determined by the PUCO) is less than or equal to $750.0 million. The Total Debt to Capitalization covenant is calculated at the end of each fiscal quarter as the sum of **DP&L's** current and long-term portion of debt, divided by the total of **DP&L's** shareholder's equity and total debt. As of December 31, 2015, **DP&L** met this financial covenant with a Total Debt to Total Capitalization ratio of 0.39 to 1.00.

The second financial covenant measures **DP&L's** EBITDA to Interest Expense ratio. Both prior to and after completion of the separation of **DP&L's** generation assets from its transmission and distribution assets, **DP&L's** EBITDA to Interest Expense ratio cannot be less than 2.50 to 1.00. The ratio is calculated at the end of each fiscal quarter, by dividing EBITDA for the four prior fiscal quarters by the interest charges for the same period. As of December 31, 2015, **DP&L** met this financial covenant with an EBITDA to Interest Expense ratio of 11.22 to 1.00.

Debt Ratings

During 2015, Fitch downgraded **DPL's** senior unsecured debt rating. Standard & Poor's and Moody's ratings did not change.

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

	DPL	DP&L	Outlook	Effective
Fitch Ratings	BB[(a)] / BB-[(b)]	BBB [(c)]	Stable	August 2015 / September 2014 [(d)]
Moody's Investors Service, Inc.	Ba3 [(b)]	Baa2 [(c)]	Stable	October 2015
Standard & Poor's Financial Services LLC	BB [(b)]	BBB- [(c)]	Stable	May 2014

Credit Ratings

The following table outlines the credit ratings (issuer/corporate rating) and outlook for each company, along with the effective dates of each rating and outlook for **DPL** and **DP&L**.

	DPL	DP&L	Outlook	Effective
Fitch Ratings	B+	BB+	Stable	August 2015 / September 2014 [(d)]
Moody's Investors Service, Inc.	Ba3	Baa3	Stable	October 2015
Standard & Poor's Financial Services LLC	BB	BB	Stable	May 2014

(a) Rating relates to **DPL's** Senior secured debt.
(b) Rating relates to **DPL's** Senior unsecured debt.
(c) Rating relates to **DP&L's** Senior secured debt.
(d) **DPL** ratings were updated in August 2015; **DP&L** ratings have not been updated since September 2014.

On August 7, 2015, Fitch downgraded **DPL's** senior unsecured debt rating from BB Stable to BB- Stable, and assigned the rating of BB Stable to **DPL's** newly issued secured debt.

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 certain 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, 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, 2015, **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, 2015, **DPL** had $17.3 million of guarantees to third parties for future financial or performance assurance under such agreements on behalf of DPLE. In addition, **DPL** had $1.9 million of guarantees on behalf of DPLER which were released in January 2016 as a result of the sale of DPLER. The guarantee arrangements entered into by **DPL** with these third parties cover present and future obligations of DPLE and present obligations of DPLER to such beneficiaries and are terminable at any time by **DPL** upon written notice to the beneficiaries. The carrying amount of obligations for commercial transactions covered by these guarantees and recorded in our Consolidated Balance Sheets was $0.5 million at December 31, 2015 and $1.6 million at December 31, 2014.

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. At December 31, 2015, **DP&L** could be responsible for the repayment of 4.9%, or $74.5 million, of a $1,519.9 million debt obligation comprised of both fixed and variable rate securities with maturities between 2016 and 2040. This would only happen if this electric generation company defaulted on its debt payments. At December 31, 2015, 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, 2015, 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	$ 2,013.7	$ 575.1	$ 50.2	$ 475.4	$ 913.0
Interest payments	576.0	99.4	164.1	146.6	165.9
Pension and postretirement payments	276.7	26.3	54.1	55.8	140.5
Coal contracts [(a)]	374.2	186.9	187.3	—	—
Purchase orders and other contractual obligations	83.8	24.4	30.0	29.4	—
Total contractual obligations	$ 3,324.4	$ 912.1	$ 485.7	$ 707.2	$ 1,219.4

	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	$ 763.1	$ 445.1	$ 0.2	$ 200.4	$ 117.4
Interest payments	142.3	16.3	15.8	14.8	95.4
Pension and postretirement payments	276.7	26.3	54.1	55.8	140.5
Coal contracts [(a)]	374.2	186.9	187.3	—	—
Purchase orders and other contractual obligations	83.8	24.4	30.0	29.4	—
Total contractual obligations	$ 1,640.1	$ 699.0	$ 287.4	$ 300.4	$ 353.3

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

Long-term debt:

DPL's Long-term debt at December 31, 2015 consists of **DPL's** unsecured notes and secured term loan, along with **DP&L's** first mortgage bonds, tax-exempt pollution control bonds 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 at December 31, 2015 consists of its first mortgage bonds, tax-exempt pollution control bonds and the WPAFB note. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 8 – Debt of the Notes to **DPL's** Consolidated Financial Statements and Note 7 – Debt 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, 2015.

Pension and postretirement payments:
At December 31, 2015, **DPL**, through its principal subsidiary **DP&L**, had estimated future benefit payments as outlined in Note 10 – Benefit Plans of Notes to **DPL's** Consolidated Financial Statements and Note 9 – Benefit Plans of Notes to **DP&L's** Financial Statements. These estimated future benefit payments are projected through 2025.

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.

Purchase orders and other contractual obligations:
At December 31, 2015, **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 $3.0 million at December 31, 2015, 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.

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; the valuation of goodwill; 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
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 7 – Goodwill and Other Intangible Assets of Notes to **DPL's** Consolidated Financial Statements discussing the impairment of goodwill at **DPL** in 2015, 2014 and 2013.

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 – Fixed-asset Impairment of Notes to **DPL's** Consolidated Financial Statements and Note 13 – Fixed-asset Impairment of Notes to **DP&L's** Financial Statements discussing the impairment of long-lived assets in 2014 and 2013.

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

We are subject to federal and state income taxes. Our income tax provision requires significant judgment and is based on calculations and assumptions that are subject to examination by the U.S. Internal Revenue Service and other tax authorities. We regularly assess the potential outcome of tax examinations when determining the adequacy of our income tax provisions by considering the technical merits of the filing position, case law, and results of previous tax examinations. Accounting guidance for uncertainty in income taxes prescribes a more-likely-than-not recognition threshold and measurement requirements for financial statement reporting of our income tax positions. Tax reserves have been established, which we believe to be adequate in relation to the potential for additional assessments. Once established, reserves are adjusted only when there is more information available or when an event occurs necessitating a change to the reserves. While we believe that the amount of the tax reserves is reasonable, it is possible that the ultimate outcome of current or future examinations may be materially different than the reserve amounts.

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. We establish a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized.

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 non-regulated 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 non-regulated 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 3 – Regulatory Assets and Liabilities of Notes to **DPL's** Consolidated Financial Statements and Note 3 – Regulatory Assets and Liabilities 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.

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.

Effective January 1, 2016 we will apply a disaggregated discount rate approach for determining service cost and interest cost for our defined benefit pension plans and post-retirement plans. Refer to Note 1 – Overview and Summary of Significant Accounting Policies of Notes to **DPL's** Consolidated Financial Statements and Note 1 – Overview and Summary of Significant Accounting Policies of Notes to **DP&L's** Financial Statements. Also see Note 10 – Benefit Plans of Notes to **DPL's** Consolidated Financial Statements and Note 9 – Benefit Plans of Notes to **DP&L's** Financial Statements for more information.

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

Discussions of legal and other matters are provided in Item 1 – Business "Environmental Matters", Item 1 – Business "Competition and Regulation" and Item 3 – Legal Proceedings. 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 – Overview and Summary of Significant Accounting Policies of Notes to **DPL's** Consolidated Financial Statements and Note 1 – Overview and Summary of Significant Accounting Policies 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

We are subject to certain market risks including, but not limited to, changes in commodity prices for electricity, coal, environmental emission allowances, and 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 stations, 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. 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 2016 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.

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 natural gas, 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. At December 31, 2015, there are no coal derivatives.

The following table provides information regarding the volume and average market price of our power forward derivative contracts at December 31, 2015 and the effect to Net income if the market price were to increase or decrease by 10%:

Power Forwards	Contract Volume (in millions of MWh)	Weighted Average Market Price per MWh	Increase / decrease in Net income (in millions)
2016 - Net purchase/(Sale) position	(5.1)	$ 33.42	$ (11.5)
2017 - Net purchase/(Sale) position	(1.1)	$ 34.16	$ (2.6)
2018 - Net purchase/(Sale) position	0.1	$ 33.14	$ 0.2

Wholesale revenues

Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins (**DP&L's** electric revenues in the wholesale market include sales to DPLER).

Approximately 46% of **DPL's** and 45% of **DP&L's** electric revenues for the year ended December 31, 2015 were from sales of excess energy and capacity in the wholesale market.

Approximately 46% of **DPL's** and 45% of **DP&L's** electric revenues for the year ended December 31, 2014 were from sales of excess energy and capacity in the wholesale market.

Approximately 45% 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.

The table below provides the effect on annual Net income (net of an estimated income tax at 35%) as of December 31, 2015 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:

$ in millions	DPL	DP&L
Effect of 10% change in price per MWh	$ 10.1	$ 10.5

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 that runs from June 1 to May 31, has conducted auctions for capacity through the 2018/19 delivery year. The clearing prices for capacity during the PJM delivery periods from 2014/15 through 2018/19 are as follows:

($/MW-day)	PJM Delivery Year				
	2014/15	2015/16	2016/17	2017/18	2018/19
Capacity clearing price	$ 126	$ 136	$ 134	$ 152	$ 165

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

	Calendar Year				
($/MW-day)	2014	2015	2016	2017	2018
Computed average capacity price	$ 85	$ 132	$ 135	$ 145	$ 159

The above tables reflect the capacity prices after the transitional auctions discussed earlier. Substantially all of **DP&L's** capacity cleared in the CP auction. The results of these auctions could have a significant effect on **DP&L's** revenues in the future.

Future capacity 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 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** had 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. Beginning January 2016, the RPM rider will no longer exist since SSO load will be 100% sourced through the competitive bid.

The table below provides estimates of the effect on annual Net income (net of an estimated income tax of 35%) as of December 31, 2015 of a hypothetical increase or decrease of $10/MW-day in the capacity auction price. The table shows the impact resulting from capacity revenue changes.

$ in millions	DPL	DP&L
Effect of $10/MW-day change in capacity auction pricing	$ 6.9	$ 5.6

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.

The capacity clearing prices listed above reflect the FERC's newly approved proposal made by PJM to implement a new CP program. The FERC's conditions on approval include requiring PJM to make additional filings to change certain energy market rules to coordinate better with the CP program and to make annual filings on the CP performance hours used in its calculations. The FERC's order approved transitional mechanisms under which the results of the auctions under the RPM program for the 2016/17 and 2017/18 periods would be modified based on transitional CP auctions that were held in the third quarter of 2015. The first full CP auction was also held in the third quarter of 2015 for the 2018/19 period.

As approved, the CP program offers the potential for higher capacity revenues, combined with substantially increased penalties for non-performance or under-performance during certain periods identified as "capacity performance hours". This linkage between non- or under-performance during certain specific hours means that a generation unit that is generally performing well on an annual basis, may incur substantial penalties if it happens to be unavailable for service during some capacity performance hours. Similarly, a generation unit that is generally performing poorly on an annual basis may avoid such penalties if its outages happen to occur only during hours that are not capacity performance hours. An annual "stop-loss" provision exists that limits the size of penalties to 150% of the net Cost of New Entry, which is a value computed by PJM. This level is likely to be larger than the capacity price established under the CP program, so that the potential exists that participation in the CP program could result in capacity penalties that exceed capacity revenues.

At present, **DP&L** is unable to project whether the CP program will be beneficial or negative to **DP&L's** operations, but the results could be material to **DP&L's** operations.

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, 2015, 2014 and 2013 were 59%, 42% and 45%, respectively. We have a significant portion of projected 2016 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 2016; 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 2016 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. 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.

The table below provides the effect on annual Net income (net of an estimated income tax at 35%) as of December 31, 2015, of a hypothetical increase or decrease of 10% in the prices of fuel and purchased power:

$ in millions	DPL	DP&L
Effect of 10% change in fuel and purchased power	$ 53.5	$ 52.1

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 $125 million secured term loan with a syndicated bank group. **DP&L's** variable-rate debt is comprised of $200 million of bank held pollution control bonds. Both variable-rate bonds bear interest based on an underlying interest rate index, typically LIBOR. Market indexes can be affected by market demand, supply, market interest rates and other economic conditions. See Note 8 – Debt of Notes to **DPL's** Consolidated Financial Statements and Note 7 – Debt of Notes to **DP&L's** Financial Statements.

The carrying value of **DPL's** debt was $2,009.4 million at December 31, 2015, consisting of **DPL's** unsecured notes, secured term loan, Capital Trust II securities along with **DP&L's** first mortgage bonds, tax-exempt pollution control bonds and the WPAFB note. All of **DPL's** existing debt was adjusted to fair value at the Merger date according to FASC 805. The fair value of this debt at December 31, 2015 was $1,975.3 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	2016	2017	2018	2019	2020	Thereafter	2015	2015
Long-term debt								
Variable-rate debt	$ —	$ 25.0	$ 25.0	$ 25.0	$ 250.0	$ —	$ 325.0	$ 325.0
Average interest rate	—%	2.7%	2.7%	2.7%	1.5%	—%		
Fixed-rate debt	$ 575.1	$ 0.1	$ 0.1	$ 200.2	$ 0.2	$ 913.0	1,688.7	1,650.3
Average interest rate	2.9%	4.2%	4.2%	6.7%	4.2%	6.9%		
Total							$ 2,013.7	$ 1,975.3

The carrying value of **DP&L's** debt was $762.9 million at December 31, 2015, consisting of its first mortgage bonds, tax-exempt pollution control bonds and the WPAFB note. The fair value of this debt at December 31, 2015 was $764.2 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. 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	2016	2017	2018	2019	2020	Thereafter	2015	2015
Long-term debt								
Variable-rate debt	$ —	$ —	$ —	$ —	$ 200.0	$ —	$ 200.0	$ 200.0
Average interest rate	—%	—%	—%	—%	1.2%	—%		
Fixed-rate debt	$ 445.1	$ 0.1	$ 0.1	$ 0.2	$ 0.2	$ 117.4	563.1	564.2
Average interest rate	1.9%	4.2%	4.2%	4.2%	4.2%	4.7%		
Total							$ 763.1	$ 764.2

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, 2015 and 2014 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. At December 31, 2015 and 2014, 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, 2015 (a)	Fair value at December 31, 2015	One Percent Interest Rate Risk	Carrying value at December 31, 2014 (a)	Fair value at December 31, 2014	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	$ 325.0	$ 325.0	$ 3.3	$ 260.0	$ 260.0	$ 2.6
Fixed-rate debt	1,684.4	1,650.3	16.5	1,899.7	1,944.8	19.4
Total	$ 2,009.4	$ 1,975.3	$ 19.8	$ 2,159.7	$ 2,204.8	$ 22.0

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

DP&L

$ in millions	Carrying value at December 31, 2015 (a)	Fair value at December 31, 2015	One Percent Interest Rate Risk	Carrying value at December 31, 2014 (a)	Fair value at December 31, 2014	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	$ 200.0	$ 200.0	$ 2.0	$ 100.0	$ 100.0	$ 1.0
Fixed-rate debt	562.9	564.2	5.6	777.1	782.5	7.8
Total	$ 762.9	$ 764.2	$ 7.6	$ 877.1	$ 882.5	$ 8.8

(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** $1,650.3 million of fixed-rate debt and not on **DPL's** financial condition or results of operations. On the variable-rate debt, the interest rate risk with respect to **DPL's** long-term debt represents the potential impact an increase of one percentage point in the interest rate has on **DPL's** results of operations related to **DPL's** $325.0 million variable-rate long-term debt outstanding at December 31, 2015.

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** $564.2 million of fixed-rate debt and not on **DP&L's** financial condition or **DP&L's** results of operations. On the variable-rate debt, the interest rate risk with respect to **DP&L's** long-term debt represents the potential impact an increase of one percentage point in the interest rate has on **DP&L's** results of operations related to **DP&L's** $200.0 million variable-rate long-term debt outstanding at December 31, 2015.

Equity price risk

At December 31, 2015, approximately 17% of the defined benefit pension plan assets were comprised of investments in equity securities and 83% 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

$60.3 million at December 31, 2015. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $6.0 million reduction in fair value at December 31, 2015 and approximately a $0.2 million increase to the 2016 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.

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.

We have audited the accompanying consolidated balance sheets of DPL Inc. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income/(loss), cash flows, and shareholder's equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule "Schedule II - Valuation and Qualifying Accounts" for each of the three years in the period ended December 31, 2015. 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 consolidated financial position of DPL Inc. at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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.

February 23, 2016
Indianapolis, Indiana

DPL INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

$ in millions	Years ended December 31, 2015	2014	2013
Revenues	**$ 1,612.8**	$ 1,716.5	$ 1,579.0
Cost of revenues:			
Fuel	**259.8**	304.5	366.7
Purchased power	**562.6**	587.9	383.0
Total cost of revenues	**822.4**	892.4	749.7
Gross margin	**790.4**	824.1	829.3
Operating expenses:			
Operation and maintenance	**361.3**	362.4	365.7
Depreciation and amortization	**134.6**	135.6	129.2
General taxes	**87.0**	87.8	76.8
Goodwill impairment	**317.0**	—	306.3
Fixed-asset impairment	—	11.5	26.2
Other	**0.4**	(3.9)	2.5
Total operating expenses	**900.3**	593.4	906.7
Operating income / (loss)	**(109.9)**	230.7	(77.4)
Other income / (expense), net			
Investment income	**0.2**	0.9	1.4
Interest expense	**(118.3)**	(126.6)	(124.0)
Charge for early redemption of debt	**(2.1)**	(30.9)	(2.8)
Other deductions	**(1.3)**	(1.5)	(3.0)
Other expense, net	**(121.5)**	(158.1)	(128.4)
Earnings (loss) from continuing operations before income tax	**(231.4)**	72.6	(205.8)
Income tax expense from continuing operations	**20.0**	15.4	19.8
Net income / (loss) from continuing operations	**(251.4)**	57.2	(225.6)
Discontinued operations (Note 16)			
Income / (loss) from discontinued operations	**11.4**	(129.2)	6.0
Income tax expense / (benefit)	**(1.0)**	2.6	2.4
Discontinued operations	**12.4**	(131.8)	3.6
Net loss	**$ (239.0)**	**$ (74.6)**	**$ (222.0)**

See Notes to Consolidated Financial Statements.

DPL INC.
STATEMENTS OF COMPREHENSIVE LOSS

$ in millions	Years ended December 31, 2015	2014	2013
Net loss	**$ (239.0)**	$ (74.6)	$ (222.0)
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $0.1, $0.2 and $0.6 for each respective period	**(0.1)**	(0.3)	(1.2)
Reclassification to earnings, net of income tax benefit / (expense) of $0.0, ($0.2) and ($0.7) for each respective period	**—**	0.2	1.4
Total change in fair value of available-for-sale securities	**(0.1)**	(0.1)	0.2
Derivative activity:			
Change in derivative fair value, net of income tax benefit / (expense) of ($10.3), $10.3 and ($10.6) for each respective period	**18.2**	(19.0)	19.7
Reclassification to earnings, net of income tax benefit / (expense) of $5.4, ($9.5) and ($2.3) for each respective period	**(10.0)**	16.9	3.4
Total change in fair value of derivatives	**8.2**	(2.1)	23.1
Pension and postretirement activity:			
Prior service cost for the period, net of income tax benefit / (expense) of $0.0, $1.3 and $0.0 for each respective period	**—**	(2.2)	—
Net gain / (loss) for the period, net of income tax benefit / (expense) of ($1.2), $7.1 and ($2.7) for each respective period	**1.6**	(12.7)	4.9
Reclassification to earnings, net of income tax benefit / (expense) of ($0.2), $0.0 and $0.3 for each respective period	**0.2**	—	0.3
Total change in unfunded pension and postretirement	**1.8**	(14.9)	5.2
Other comprehensive income / (loss)	**9.9**	(17.1)	28.5
Net comprehensive loss	**$ (229.1)**	$ (91.7)	$ (193.5)

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions		December 31, 2015		December 31, 2014
ASSETS				
Current assets:				
Cash and cash equivalents	$	**32.4**	$	17.0
Restricted cash		**92.7**		16.8
Accounts receivable, net (Note 2)		**120.9**		136.5
Inventories (Note 2)		**109.1**		100.2
Taxes applicable to subsequent years		**81.2**		77.8
Regulatory assets, current (Note 3)		**14.4**		44.2
Other prepayments and current assets		**46.6**		38.9
Assets held for sale - current (Note 16)		**62.2**		67.3
Total current assets		**559.5**		498.7
Property, plant and equipment:				
Property, plant and equipment		**2,909.0**		2,754.1
Less: Accumulated depreciation and amortization		**(432.3)**		(317.9)
		2,476.7		2,436.2
Construction work in process		**85.0**		76.4
Total net property, plant and equipment		**2,561.7**		2,512.6
Other non-current assets:				
Regulatory assets, non-current (Note 3)		**179.9**		167.5
Goodwill (Note 7)		**—**		317.0
Intangible assets, net of amortization (Note 7)		**5.0**		7.8
Other deferred assets		**34.7**		39.7
Assets held for sale - non-current (Note 16)		**—**		34.5
Total other non-current assets		**219.6**		566.5
Total Assets	$	**3,340.8**	$	3,577.8
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities:				
Current portion - long-term debt (Note 8)	$	**574.9**	$	20.1
Accounts payable		**97.5**		94.4
Accrued taxes		**142.4**		102.6
Accrued interest		**21.4**		27.2
Customer security deposits		**15.2**		14.4
Regulatory liabilities, current (Note 3)		**24.4**		4.4
Insurance and claims costs		**5.9**		6.4
Other current liabilities		**54.5**		46.3
Deposit received on sale of DPLER (Note 16)		**75.5**		—
Liabilities held for sale - current (Note 16)		**1.6**		17.1
Total current liabilities		**1,013.3**		332.9
Non-current liabilities:				
Long-term debt (Note 8)		**1,434.5**		2,139.6
Deferred taxes (Note 9)		**568.7**		587.3
Taxes payable		**84.1**		80.7
Regulatory liabilities, non-current (Note 3)		**127.0**		124.1
Pension, retiree and other benefits (Note 10)		**87.1**		95.9
Other deferred credits		**88.3**		50.5
Liabilities held for sale - non-current (Note 16)		**—**		0.2
Total non-current liabilities		**2,389.7**		3,078.3
Redeemable preferred stock of subsidiary (Note 11)		**18.4**		18.4
Commitments and contingencies (Note 12)				
Common shareholder's equity:				
Common stock:				
1,500 shares authorized; 1 share issued and outstanding at December 31, 2015 and 2014		**—**		—
Other paid-in capital		**2,237.7**		2,237.4
Accumulated other comprehensive income		**17.4**		7.5
Retained earnings / (deficit)		**(2,335.7)**		(2,096.7)
Total common shareholder's equity		**(80.6)**		148.2
Total Liabilities and Shareholder's Equity	$	**3,340.8**	$	3,577.8

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years ended December 31,		
$ in millions	2015	2014	2013
Cash flows from operating activities:			
Net loss	$ (239.0)	$ (74.6)	$ (222.0)
Adjustments to reconcile Net loss to Net cash from operating activities			
Depreciation and amortization	138.8	139.8	132.9
Amortization of intangibles	—	1.2	7.1
Amortization of debt market value adjustments	(1.1)	0.3	(14.4)
Amortization of deferred financing costs	5.9	6.3	5.0
Unrealized loss on derivatives	5.8	3.0	5.9
Deferred income taxes	(17.1)	17.7	24.0
Charge for early redemption of debt	2.1	30.9	2.8
Goodwill impairment [(a)]	317.0	135.8	306.3
Fixed-asset impairment	—	11.5	26.2
Loss / (Gain) on asset disposal	0.4	(3.9)	2.5
Changes in certain assets and liabilities:			
Accounts receivable	43.4	0.5	7.4
Inventories	(9.0)	(24.9)	27.4
Prepaid taxes	(1.3)	(0.9)	0.7
Taxes applicable to subsequent years	(3.4)	(7.1)	(1.4)
Deferred regulatory costs, net	21.8	5.4	7.6
Accounts payable	(5.1)	32.1	(5.8)
Accrued taxes payable	43.8	20.7	(5.5)
Accrued interest payable	(5.7)	(1.3)	(3.3)
Other current and deferred liabilities	(10.4)	(40.6)	1.5
Pension, retiree and other benefits	(0.7)	19.1	1.8
Unamortized investment tax credit	(0.5)	(0.5)	(0.5)
Insurance and claims costs	(0.5)	(0.2)	(4.8)
Other	23.3	(26.2)	1.4
Net cash from operating activities	308.5	244.1	302.8
Cash flows from investing activities:			
Capital expenditures	(137.2)	(118.1)	(124.4)
Proceeds from sale of property	1.3	10.7	0.8
Insurance proceeds	—	0.3	7.6
Purchase of renewable energy credits	(0.8)	(3.5)	(3.9)
Decrease / (increase) in restricted cash	(0.4)	(3.3)	(2.8)
Other investing activities, net	0.4	1.3	(1.2)
Net cash from investing activities	(136.7)	(112.6)	(123.9)
Cash flows from financing activities:			
Deferred financing costs	(6.9)	(3.6)	(15.3)
Retirement of debt	(474.5)	(335.0)	(945.1)
Premium paid for early redemption of debt	—	(29.1)	(2.4)
Issuance of long-term debt	325.0	200.0	645.0
Borrowings from revolving credit facilities	80.0	190.0	50.0
Repayment of borrowings from revolving credit facilities	(80.0)	(190.0)	(50.0)
Net cash from financing activities	(156.4)	(167.7)	(317.8)
Cash and cash equivalents:			
Net increase / (decrease) in cash	15.4	(36.2)	(138.9)
Balance at beginning of period	17.0	53.2	192.1
Cash and cash equivalents at end of period	$ 32.4	$ 17.0	$ 53.2
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 111.6	$ 117.3	$ 137.5
Income taxes paid / (refunded), net	$ 0.8	$ 0.7	$ (5.2)
Non-cash financing and investing activities:			
Accruals for capital expenditures	$ 18.6	$ 16.3	$ 14.7

(a) Goodwill impairment of $135.8 million in 2014 has been reclassified to Discontinued operations in the Consolidated Statement of Operations.

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED 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/ (Deficit)	Total
Year ended December 31, 2013						
Beginning balance	1	$ —	$ 2,236.7	$ (3.9)	$ (1,806.0)	$ 426.8
Net comprehensive loss				28.5	(222.0)	(193.5)
Common stock dividends					—	—
Other [(b)]			0.3		5.9	6.2
Ending balance	1	—	2,237.0	24.6	(2,022.1)	239.5
Year ended December 31, 2014						
Net comprehensive loss				(17.1)	(74.6)	(91.7)
Other			0.4		—	0.4
Ending balance	1	—	2,237.4	7.5	(2,096.7)	148.2
Year ended December 31, 2015						
Net comprehensive loss				**9.9**	**(239.0)**	**(229.1)**
Other			**0.3**			**0.3**
Ending balance	**1**	**$ —**	**$ 2,237.7**	**$ 17.4**	**$ (2,335.7)**	**$ (80.6)**

(a) 1,500 shares authorized
(b) $5.9 million of dividends declared in 2012 were reversed in 2013.

See Notes to Consolidated Financial Statements.

DPL Inc.
Notes to Consolidated Financial Statements
For the years ended December 31, 2015, 2014 and 2013

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** one reportable segment is the Utility segment, comprised of its **DP&L** subsidiary. See Note 14 – Business Segments for more information relating to 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. 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 services are still regulated. **DP&L** has the exclusive right to provide such service to its approximately 517,000 customers located in West Central Ohio. Additionally, **DP&L** procures and provides 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 five coal-fired power stations. Beginning in 2014, **DP&L** no longer supplied 100% of the generation for SSO customers and starting January 2016, SSO is now 100% competitively bid. 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 sold electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

In accordance with the ESP Order, on December 30, 2013, **DP&L** filed an application with the PUCO stating its plan to transfer or sell its generation assets. On July 14, 2014, **DP&L** announced its decision to retain **DP&L's** generation assets. On September 17, 2014 the PUCO ordered that **DP&L's** application as amended and updated was approved. **DP&L** is required to sell or transfer its generation assets by January 1, 2017 and continues to look at multiple options to effectuate the separation, including transfer into an unregulated affiliate of **DPL** or through a sale.

DPLER was sold by **DPL** on January 1, 2016. DPLER sold competitive retail electric service, under contract, to residential, commercial and industrial customers. DPLER had approximately 125,000 customers located throughout Ohio. DPLER's operations included those of its wholly-owned subsidiary MC Squared through April 1, 2015, when DPLER sold MC Squared. Approximately 110,000 of DPLER's customers were also electric distribution customers of **DP&L**. DPLER did not own any transmission or generation assets, and it purchased all of its electric energy from **DP&L** to meet its sales obligations. DPLER's sales reflect the general economic conditions and seasonal weather patterns of the area. See Note 16 – Discontinued Operations for more information.

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. Effective February 1, 2016, DPLE was renamed AES Ohio Generation, LLC. **DPL** owns all of the common stock of its subsidiaries.

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 1,219 people at January 31, 2016, of which 1,189 were employed by **DP&L**. Approximately 60% of all **DPL** employees are under a collective bargaining agreement which expires on October 31, 2017.

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 4 – Property, Plant and Equipment for more information.

All material intercompany accounts and transactions are eliminated in consolidation.

Certain immaterial amounts from prior periods 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; assets and liabilities related to employee benefits; goodwill; and intangibles.

Valuation of Goodwill
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. See Note 7 – Goodwill and Other Intangible Assets for information regarding the impairments of goodwill in 2015, 2014 and 2013.

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 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. The power sales and purchases within **DP&L's** service territory are reported on a net hourly basis as revenues or purchased power on our Consolidated Statements 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. Amounts are written off when reasonable collections efforts have been exhausted.

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 $2.0 million, $1.5 million and $1.5 million in the years ended December 31, 2015, 2014 and 2013, 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. See Note 15 – Fixed-asset Impairment for more information.

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

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 that approximated 4.6% in 2015, 5.3% in 2014 and 5.8% in 2013. Depreciation expense was $125.9 million, $128.1 million and $120.9 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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. 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 **DP&L** 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 3 – Regulatory Assets and Liabilities for more information.

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 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. Emission allowances are amortized as they are used in our operations on a FIFO basis. Renewable energy credits are carried on a weighted average cost basis and amortized as they are used or retired. See Note 7 – Goodwill and Other Intangible Assets for additional information.

Income Taxes
Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. We establish an allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. Our tax positions are evaluated under a more likely than not recognition threshold and measurement analysis before they are recognized for financial statement reporting. Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid within one year. Our policy for interest and penalties is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statement of Operations.

Income taxes payable, which are includable in allowable costs for ratemaking purposes in future years, are recorded as regulatory assets with a corresponding deferred tax liability. Investment tax credits that reduced federal income taxes in the years they arose have been deferred and are being amortized to income over the useful lives of the properties in accordance with regulatory treatment. See Note 3 – Regulatory Assets and Liabilities for additional information.

DPL and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. 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 9 – Income Taxes 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 bases for public equity security and fixed maturity investments are 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 and certain other taxes are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Operations. The amounts for the years ended December 31, 2015, 2014 and 2013, were $49.9 million, $50.8 million and $50.5 million, respectively.

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 includes restrictions imposed by agreements related to deposits held as collateral. At December 31, 2015, restricted cash also includes cash received in connection with the sale of DPLER on January 1, 2016. See Note 16 – Discontinued Operations for additional information regarding the sale of DPLER.

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, which results in changes in fair value being recorded within accumulated other comprehensive income, a component of shareholder's equity. 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 6 – Derivative Instruments and Hedging Activities 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 solely to us, our subsidiaries and, in some cases, our partners in commonly-owned facilities we operate, for workers' compensation, general liability, and property damage on an ongoing basis. MVIC maintains an active run-off policy for directors' and officers' liability and fiduciary through their expiration in 2017, which may or may not be renewed at that time. Insurance and Claims Costs on **DPL's** Consolidated Balance Sheets associated with MVIC include estimated liabilities of approximately $5.9 million and $6.4 million at December 31, 2015 and 2014, respectively. In addition, **DP&L** is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. **DP&L** has estimated liabilities for medical, life, and disability reserves for claims costs below certain coverage thresholds of third-party providers of approximately $13.7 million and $15.6 million at December 31, 2015 and 2014, 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 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.

Pension and Postretirement Benefits
We recognize, in our Consolidated Balance Sheets, an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in the funded status recognized in AOCI, except for those portions of our pension and postretirement obligations that can be recovered through future rates. All plan assets are recorded at fair value. We follow the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

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.

Effective January 1, 2016, we will apply a disaggregated discount rate approach for determining service cost and interest cost for its defined benefit pension plans and post-retirement plans. This approach is consistent with the requirements of ASC 715 and is considered to be preferential to the aggregated single rate discount approach, which has historically been used in the U.S., because it is more consistent with the philosophy of a full yield curve valuation.

The change in discount rate approach did not have an impact on the measurement of the benefit obligations at December 31, 2015, nor will it impact future remeasurements. This change in approach will impact the service cost and interest cost recorded in 2016 and future years. It will also impact the actuarial gains and losses recorded in future years, as well as the amortization thereof.

The expected 2016 service costs and interest costs included in Note 10 – Benefit Plans reflect the change in methodology described above. The impact of the change in approach on expected service costs in 2016 is shown below:

$ in millions	Expected 2016 Service Cost			Expected 2016 Interest Cost		
	Disaggregated rate approach	Aggregate rate approach	Impact of change	Disaggregated rate approach	Aggregate rate approach	Impact of change
Total Pension	$ 5.7	$ 6.1	$ (0.4)	$ 14.8	$ 17.9	$ (3.1)
Total Postretirement Benefits	$ 0.2	$ 0.2	$ —	$ 0.6	$ 0.7	$ (0.1)
Total	$ 5.9	$ 6.3	$ (0.4)	$ 15.4	$ 18.6	$ (3.2)

See Note 10 – Benefit Plans for more information.

Related Party Transactions
In the normal course of business, **DPL** enters into transactions with related parties. All material intercompany accounts and transactions are eliminated in **DPL's** Consolidated Financial Statements.

See Note 13 – Related Party Transactions for more information on Related Party Transactions.

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 $0.3 million and $0.3 million at December 31, 2015 and 2014, respectively, is included in Other deferred assets within Other noncurrent assets. **DPL** also has a note payable to the Trust amounting to $15.6 million and $15.6 million at December 31, 2015 and December 31, 2014, respectively, that was established upon the Trust's deconsolidation in 2003. See Note 8 – Debt 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.

New accounting pronouncements adopted

ASU No. 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes
Effective December 31, 2015, we prospectively adopted ASU No. 2015-17, which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. As a result, each jurisdiction will now only have one net noncurrent deferred tax asset or liability. The guidance does not change the existing requirement that only permits offsetting within a jurisdiction; that is, companies will remain prohibited from offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. Additionally, the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by the update. As we elected to apply this ASU prospectively, prior periods were not adjusted.

ASU No. 2015-13, Derivatives and Hedging (Topic 815):Derivatives and Hedging: Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Market
In August 2015, the FASB issued ASU No. 2015-13, which resolves the diversity in practice resulting from determining whether certain contracts qualify for the normal purchases and normal sales scope exception under ASC Topic 815, Derivatives and Hedging. This standard clarifies that entities would not be precluded from applying the normal purchases and normal sales exception to certain forward contracts that necessitate the transmission of electricity through, or delivery to a location within, a nodal energy market. The standard is effective upon issuance and should be applied prospectively. As we had designated qualifying contracts as normal purchase or normal sales, there was no impact on our financial statements upon adoption of this standard.

Accounting pronouncements issued but not yet effective

ASU No. 2016-01, Financial Instruments — Overall (Topic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities
In January 2016, the FASB issued ASU 2016-01, which was designed to improve the recognition and measurement of financial instruments through targeted changes to existing GAAP. The guidance requires equity investments (except those that are accounted for under the equity method of accounting or result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income; that entities use the exit price notion when measuring financial instrument fair values; that an entity separate presentation of financial assets and liabilities by measurement category and form of financial asset on the Balance Sheets or Notes to the financial statements; that an entity present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk (or "own credit") when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. Also, the standard eliminates the requirement for public entities to disclose the methods and significant assumptions used to estimate the fair value required to be disclosed for financial instruments measured at amortized cost on the Balance Sheets. The standard is effective beginning with interim periods starting after December 31, 2017 and cannot be applied early. We are currently evaluating the applicability and materiality of the standard, but we do not anticipate a material impact on our consolidated financial statements.

ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments
In September 2015, the FASB issued ASU 2015-16, which simplifies the measurement-period adjustments in business combinations. It eliminates the requirement that an acquirer in a business combination account for measurement-period adjustments retrospectively. An acquirer will recognize a measurement-period adjustment during the period in which it determines the amount of the adjustment. The standard is effective for public entities for annual reporting periods beginning after December 15, 2015, and interim periods therein. Early adoption is permitted for financial statements that have not been issued. The new guidance should be applied prospectively to adjustments to provisional amounts that occur after the effective date of this standard. We will adopt this standard on January 1, 2016, which is not expected to have a material impact on our consolidated financial statements.

ASU No. 2015-03, Interest – Imputation of Interest (Subtopic 835-30)
In April 2015, the FASB issued ASU No. 2015-03, which simplifies the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update. The standard is effective for annual reporting periods beginning after December 15, 2015 and interim periods therein, and requires the use of the full retrospective approach. Early adoption is permitted for financial statements that have not been previously issued. As of December 31, 2015, **DPL** had approximately $16.1 million in deferred financing costs classified in other current and other non-current assets that would be reclassified to reduce the related debt liabilities upon adoption of ASU No. 2015-03.

ASU No. 2015-15, Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements
In August 2015, the FASB issued ASU No. 2015-15, which clarifies that the SEC Staff would not object to an entity presenting debt issuance costs related to line-of-credit arrangements as an asset that is subsequently amortized ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. This standard should be adopted concurrent with adoption of ASU 2015-03 (which is described above). As of December 31, 2015, we had deferred financing costs related to lines of credit of approximately $3.1 million recorded within Other noncurrent assets that would not be reclassified upon adoption of this standard.

ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory
In July 2015, the FASB issued ASU No. 2015-11, which simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with a lower of cost or net realizable value test. The standard is effective for public entities for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted. The new guidance must be applied prospectively. As we already used the net realizable value to make lower of cost or market determinations, there will be no impact on our financial statements upon adoption of this standard.

ASU No. 2015-05, Intangibles – Goodwill and Other: Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued ASU No. 2015-05, which clarifies how customers in cloud computing arrangements should determine whether the arrangement includes a software license and eliminates the existing requirement for customers to account for software licenses they acquired by analogizing to the accounting guidance on leases. The standard is effective for annual reporting periods beginning after December 15, 2015 and interim periods therein. Early adoption is permitted. The standard permits the use of a prospective or retrospective approach. As all of our cloud computing arrangements will continue to be accounted for as service agreements, there will be no impact on our financial statements upon the adoption of this standard.

ASU No. 2014-05, Presentation of Financial Statements: Going Concern

The FASB recently issued ASU 2014-15 "Presentation of Financial Statements - Going Concern (Subtopic 205-40: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern)" effective for annual and interim periods ending after December 15, 2016. ASU 2014-15 requires management to evaluate whether there are conditions or events, considered in aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. There are required disclosures if substantial doubt is identified including documentation of: principal conditions or events that raised substantial doubt about the entity's ability to continue as a going concern (before consideration of management's plans), management's evaluation of the significance of those conditions or events in relation to the entity's ability to meet its obligations, and management's plans that alleviated substantial doubt about the entity's ability to continue as a going concern. This ASU is not expected to have any impact on our overall results of operations, financial position or cash flows.

ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606)

In May 2014, the FASB issued ASU No. 2014-09, which clarifies principles for recognizing revenue and will result in a common revenue standard for U.S. GAAP and International Financial Reporting Standards. The objective of the new standard is to provide a single and comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The standard requires an entity to recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contract with Customers (Topic 606): Deferral of the Effective Date, which deferred the effective date of ASU 2014-09 by one year, resulting in the new revenue standard being effective for annual reporting periods beginning after December 15, 2017 and interim periods therein. Early adoption is now permitted only as of the original effective date for public entities (that is, no earlier than 2017 for calendar year-end entities). The standard permits the use of either a full retrospective or modified retrospective approach. We have not yet selected a transition method and are currently evaluating the impact of adopting the standard on our financial statements.

ASU No. 2015-02, Consolidation – Amendments to the Consolidation Analysis (Topic 810)

In February 2015, the FASB issued ASU 2015-02, which makes targeted amendments to the current consolidation guidance and ends the deferral granted to investment companies from applying the Variable Interest Entity (VIE) guidance. The standard amends the evaluation of whether (1) fees paid to a decision-maker or service providers represent a variable interest, (2) a limited partnership or similar entity has the characteristics of a VIE and (3) a reporting entity is the primary beneficiary of a VIE. The standard is effective for annual periods beginning after December 15, 2015 and interim periods therein. Early adoption is permitted. We do not expect this standard to have an impact on our financial statements upon adoption.

Note 2 – Supplemental Financial Information

$ in millions	December 31, 2015	December 31, 2014
Accounts receivable, net		
Unbilled revenue	**$ 43.3**	$ 49.1
Customer receivables	**56.4**	70.1
Amounts due from partners in jointly-owned stations	**16.0**	15.2
Other	**6.0**	3.0
Provisions for uncollectible accounts	**(0.8)**	(0.9)
Total accounts receivable, net	**$ 120.9**	$ 136.5
Inventories		
Fuel and limestone	**$ 72.2**	$ 65.3
Plant materials and supplies	**34.9**	33.5
Other	**2.0**	1.4
Total inventories, at average cost	**$ 109.1**	$ 100.2

Accounts receivable of $31.0 million and $64.4 million as of December 31, 2015 and 2014 have been excluded from the above table as they have been reclassified as "Assets held for sale". See Note 16 – Discontinued Operations.

Accumulated Other Comprehensive Income / (Loss)

The amounts reclassified out of Accumulated Other Comprehensive Income / (Loss) by component during the years ended December 31, 2015, 2014 and 2013 are as follows:

Details about Accumulated Other Comprehensive Income / (Loss) Components	**Affected line item in the Consolidated Statements of Operations**	**Years ended December 31,**		
$ in millions		**2015**	2014	2013
Gains and losses on Available-for-sale securities activity (Note 5):				
	Other income / (deductions)	**$ —**	$ 0.4	$ 2.1
	Tax expense	**—**	(0.2)	(0.7)
	Net of income taxes	**—**	0.2	1.4
Gains and losses on cash flow hedges (Note 6):				
	Interest Expense	**(1.1)**	(1.3)	—
	Revenue	**(18.7)**	28.4	2.2
	Purchased power	**4.4**	(0.7)	3.5
	Total before income taxes	**(15.4)**	26.4	5.7
	Tax benefit / (expense)	**5.4**	(9.5)	(2.3)
	Net of income taxes	**(10.0)**	16.9	3.4
Amortization of defined benefit pension items (Note 10):				
	Operations and maintenance	**0.4**	—	—
	Tax expense	**(0.2)**	—	0.3
	Net of income taxes	**0.2**	—	0.3
Total reclassifications for the period, net of income taxes		**$ (9.8)**	$ 17.1	$ 5.1

The changes in the components of Accumulated Other Comprehensive Income / (Loss) during the years ended December 31, 2015 and 2014 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 at December 31, 2013	$ 0.6	$ 20.6	$ 3.4	$ 24.6
Other comprehensive loss before reclassifications	(0.3)	(19.0)	(14.9)	(34.2)
Amounts reclassified from accumulated other comprehensive income / (loss)	0.2	16.9	—	17.1
Net current period other comprehensive loss	(0.1)	(2.1)	(14.9)	(17.1)
Balance at December 31, 2014	0.5	18.5	(11.5)	7.5
Other comprehensive income / (loss) before reclassifications	**(0.1)**	**18.2**	**1.6**	**19.7**
Amounts reclassified from accumulated other comprehensive income / (loss)	**—**	**(10.0)**	**0.2**	**(9.8)**
Net current period other comprehensive income / (loss)	**(0.1)**	**8.2**	**1.8**	**9.9**
Balance at December 31, 2015	**$ 0.4**	**$ 26.7**	**$ (9.7)**	**$ 17.4**

Note 3 – Regulatory Assets and Liabilities

In accordance with FASC 980, we have recognized total regulatory assets of $194.3 million and $211.7 million at December 31, 2015 and 2014, respectively, and total regulatory liabilities of $151.4 million and $128.5 million at December 31, 2015 and 2014, respectively. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 1 – Overview and Summary of Significant Accounting Policies for accounting policies regarding Regulatory Assets and Liabilities.

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

$ in millions	Type of Recovery	Amortization Through	December 31, 2015	2014
Regulatory assets, current:				
Fuel and purchased power recovery costs	A	2016	$ 13.9	$ 16.3
Economic development costs	A	2016	0.5	2.1
Deferred storm costs	B	2015	—	22.3
Energy efficiency program	A	2016	—	1.8
Other miscellaneous	A	2016	—	1.7
Total regulatory assets, current			14.4	44.2
Regulatory assets, non-current:				
Pension benefits	B	Ongoing	$ 91.6	$ 99.6
Deferred recoverable income taxes	B/C	Ongoing	36.4	43.1
Fuel costs	B	Undetermined	12.7	—
Unrecovered OVEC charges	D	Undetermined	10.5	—
Unamortized loss on reacquired debt	B	Various	9.0	9.9
Smart grid and advanced metering infrastructure costs	D	Undetermined	7.3	6.6
Generation separation costs	D	Undetermined	3.9	1.6
Retail settlement system costs	D	Undetermined	3.1	3.1
Consumer education campaign	D	Undetermined	3.0	3.0
Rate case costs	D	Undetermined	1.9	—
Other miscellaneous	D	Undetermined	0.5	0.6
Total regulatory assets, non-current			179.9	167.5
Total regulatory assets			$ 194.3	$ 211.7
Regulatory liabilities, current:				
Energy efficiency program			$ 9.2	$ —
Competitive bidding			9.1	—
Transmission costs			3.7	2.9
Reconciliation rider			2.1	—
Other miscellaneous			0.3	1.5
Total regulatory liabilities, current			24.4	4.4
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated property			$ 121.8	$ 119.3
Postretirement benefits			5.2	4.8
Total regulatory liabilities, non-current			127.0	124.1
Total regulatory liabilities			$ 151.4	$ 128.5

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

Regulatory assets

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. The audit for 2014 is in process. The costs recovered through the fuel rider have decreased significantly over the past three years as more SSO supply is provided through the competitive bid. While no further fuel or purchased power costs will be recoverable through the rider, it will continue for up to six months to allow for recovery of the ending deferral amount.

Fuel costs - long-term represent unrecovered fuel costs related to **DP&L's** fuel rider from 2010 through 2015 resulting from a declining SSO customer base. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Economic development costs represent costs incurred to promote economic development within the State of Ohio. These costs are being recovered through an Economic Development Rider that is subject to a bi-annual true-up process for any over/under recovery of costs.

Deferred storm costs represent costs incurred to repair the damage to **DP&L's** distribution equipment by major storms in 2008, 2011 and 2012. All such costs have now been recovered.

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. In addition to recovery of program costs, this rider has allowed for **DP&L** to recover lost margin associated with decreases in sales as a result of the programs implemented. The authority to recover lost margin included a maximum amount, which **DP&L** reached in the fourth quarter of 2015. Consequently, we discontinued accruing an asset for lost revenues after the maximum was reached. In addition, this rider provides that **DP&L** can earn a "shared savings" incentive that is tiered depending upon the level of success the programs reach. In 2014 and 2015, the maximum shared savings was accrued based upon performance, which is equal to $4.5 million per year, after income taxes.

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 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.

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.

Unrecovered OVEC charges represent the portion of capacity charges from OVEC that were not recoverable through **DP&L's** fuel rider beginning in October 2014. **DP&L** expects to recover these costs through a future rate proceeding.

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

Smart Grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and the 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. This plan is currently under development and we plan to seek recover of these deferred costs in a regulatory rate proceeding in the near future. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

Generation separation costs represent financing, redemption and other costs related to the divestiture of **DP&L's** generation assets. The PUCO directed **DP&L** to divest its generation assets by January 1, 2017. **DP&L** requested and was granted permission by the PUCO to defer all financing, redemption and related costs it incurs to transfer its generation assets. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

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. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation. **DP&L** has requested recovery of these costs as part of its pending distribution rate case filing.

Rate case costs represent costs associated with preparing a distribution rate case. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Regulatory liabilities

Energy efficiency program costs see "*Regulatory Assets - Energy efficiency program costs*" above.

Competitive bidding represents costs associated with the development and implementation of a Competitive Bidding Process, establishing contracts to supply power for a portion of **DP&L's** Standard Service Offer load, as well as the net over/under recovery of the cost of the power purchased from the bid winners.

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.

Reconciliation rider represents the costs that exceed 10 percent of the base amount of the following riders: Fuel, RPM, Alternative Energy and Competitive Bidding. This rider is in an overcollection position and will be discontinued after this overcollection has been refunded to customers.

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 4 – Property, Plant and Equipment

The following is a summary of **DPL's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2015 and 2014:

	December 31,			
$ in millions	**2015**	**Composite Rate**	2014	Composite Rate
Regulated:				
Transmission	**$ 239.4**	**3.9%**	$ 227.5	4.1%
Distribution	**1,085.7**	**5.0%**	1,011.7	5.4%
General	**65.9**	**12.4%**	62.5	12.4%
Non-depreciable	**62.5**	**N/A**	61.6	N/A
Total regulated	**1,453.5**		1,363.3	
Unregulated:				
Production / Generation	**1,418.7**	**4.2%**	1,354.9	5.4%
Other	**17.0**	**8.1%**	16.1	5.5%
Non-depreciable	**19.8**	**N/A**	19.8	N/A
Total unregulated	**1,455.5**		1,390.8	
Total property, plant and equipment in service	**$ 2,909.0**	**4.6%**	$ 2,754.1	5.3%

DP&L and certain other Ohio utilities have undivided ownership interests in five 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. At December 31, 2015, **DP&L** had $39.0 million of construction work in process at such facilities. **DP&L's** share of the operations of such facilities is included within the corresponding line in the Statements 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.

Coal-fired facilities

DP&L's undivided ownership interest in such facilities at December 31, 2015, is as follows:

	DP&L Share		**DPL** Carrying Value		
	Ownership (%)	Summer Production Capacity (MW)	Gross Plant In Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)
Jointly-owned production units					
Conesville - Unit 4	16.5	129	$ 26	$ 4	$ 1
Killen - Unit 2	67.0	402	342	29	2
Miami Fort - Units 7 and 8	36.0	368	219	32	6
Stuart - Units 1 through 4	35.0	808	236	19	18
Zimmer - Unit 1	28.1	371	188	44	12
Transmission (at varying percentages)			43	8	—
Total		2,078	$ 1,054	$ 136	$ 39

Each of the above generating units has SCR and FGD equipment installed.

Beckjord Unit 6 was retired effective October 1, 2014, and **DP&L's** sale of its interest in East Bend closed on December 30, 2014.

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 are associated with the retirement of our long-lived assets, consisting 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, 2013	$	24.4
Calendar 2014		
Additions		3.6
Accretion expense		0.9
Settlements		(2.0)
Balance at December 31, 2014		26.9
Calendar 2015		
Additions		40.3
Accretion expense		1.9
Settlements		(3.2)
Balance at December 31, 2015	$	65.9

Asset Removal Costs

We continue to record costs of removal for our regulated transmission and distribution assets through our depreciation rates and recover those amounts in rates charged to our customers. There are no known legal AROs associated with these assets. We have recorded $121.8 million and $119.3 million in estimated costs of removal at December 31, 2015 and 2014, respectively, as regulatory liabilities for our transmission and distribution property. These amounts represent the excess of the cumulative removal costs recorded through depreciation rates versus the cumulative removal costs actually incurred. See Note 3 – Regulatory Assets and Liabilities for additional information.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		
Balance at December 31, 2013	$	115.0
Calendar 2014		
Additions		19.6
Settlements		(15.3)
Balance at December 31, 2014		119.3
Calendar 2015		
Additions		24.3
Settlements		(21.8)
Balance at December 31, 2015	$	121.8

Note 5 – Fair Value

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, 2015 and 2014. See Note 6 – Derivative Instruments and Hedging Activities for the fair values of our derivative instruments.

	December 31, 2015		December 31, 2014	
$ in millions	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets				
Money market funds	$ 0.2	$ 0.2	$ 0.1	$ 0.1
Equity securities	3.0	3.8	2.7	3.7
Debt securities	4.4	4.3	4.7	4.7
Hedge Funds	0.4	0.4	0.8	0.8
Real Estate	0.3	0.3	0.4	0.4
Total assets	$ 8.3	$ 9.0	$ 8.7	$ 9.7
Liabilities				
Debt	$ 2,009.4	$ 1,975.3	$ 2,159.7	$ 2,204.8

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); and
- 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, 2015 and 2014.

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 the carrying value, 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 $0.7 million ($0.5 million after tax) in unrealized gains and $0.1 million ($0.1 million after tax) in unrealized losses on the Master Trust assets in AOCI at December 31, 2015, and $0.8 million ($0.5 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2014.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. During the past twelve months, an immaterial amount of unrealized gains were reversed into earnings. Over the next twelve months, an immaterial amount of unrealized gains is expected to be reversed to earnings.

The fair value of assets and liabilities at December 31, 2015 and the respective category within the fair value hierarchy for **DPL** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2015 (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	3.8	—	3.8	—
Debt securities	4.3	—	4.3	—
Hedge Funds	0.4	—	0.4	—
Real Estate	0.3	—	0.3	—
Total Master trust assets	9.0	0.2	8.8	—
Derivative assets				
Forward power contracts	30.5	—	30.5	—
FTRs	0.2	—	—	0.2
Total Derivative assets	$ 30.7	$ —	$ 30.5	$ 0.2
Total assets	$ 39.7	$ 0.2	$ 39.3	$ 0.2
Liabilities				
FTRs	0.5	$ —	$ —	$ 0.5
Forward power contracts	27.0	—	23.9	3.1
Total derivative liabilities	27.5	—	23.9	3.6
Long-term debt	1,975.3	—	1,957.2	18.1
Total liabilities	$ 2,002.8	$ —	$ 1,981.1	$ 21.7

(a) Includes credit valuation adjustment.

The fair value of assets and liabilities at December 31, 2014 and the respective category within the fair value hierarchy for **DPL** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2014 (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	$ 0.1	$ 0.1	$ —	$ —
Equity securities	3.7	3.7	—	—
Debt securities	4.7	4.7	—	—
Hedge Funds	0.8	—	0.8	—
Real Estate	0.4	0.4	—	—
Total Master trust assets	9.7	8.9	0.8	—
Derivative assets				
Forward power contracts	14.9	—	13.7	1.2
Total derivative assets	14.9	—	13.7	1.2
Total assets	$ 24.6	$ 8.9	$ 14.5	$ 1.2
Liabilities				
FTRs	$ 0.6	$ —	$ —	$ 0.6
Heating oil futures	0.4	0.4	—	—
Natural gas futures	0.1	0.1	—	—
Forward power contracts	11.1	—	11.1	—
Total derivative liabilities	12.2	0.5	11.1	0.6
Long-term debt	2,204.8	—	2,186.6	18.2
Total liabilities	$ 2,217.0	$ 0.5	$ 2,197.7	$ 18.8

(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 (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.
- 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. The WPAFB note is not publicly traded. Fair value is assumed to equal carrying value. These fair value inputs are considered

Level 3 in the fair value hierarchy as there are no observable inputs. Additional Level 3 disclosures were not presented since debt is not recorded at fair value.

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

Non-recurring Fair Value Measurements
We use the cost approach to determine the fair value of our AROs, which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. AROs for asbestos, ash ponds, underground storage tanks, and river structures increased by a net amount of $39.0 million ($25.4 million after tax) and $2.5 million ($1.6 million after tax) during the 12 months ended December 31, 2015 and 2014, respectively. The majority of the increase for 2015 is due to a net increase in the ARO for ash ponds of $40.3 million ($26.2 million after tax) as a result of new rules promulgated by the USEPA that were published in the Federal Register in April 2015 and became effective in October 2015. See Note 4 – Property, Plant and Equipment for more information about AROs.

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, 2015**				
	Carrying Amount	**Fair Value Level 1**	**Fair Value Level 2**	**Fair Value Level 3**	**Gross Loss**
Goodwill [b]					
DP&L reporting unit	$ 317.0	$ —	$ —	$ —	$ 317.0

$ in millions	Year ended December 31, 2014				
	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 (East Bend)	$ 14.2	$ —	$ —	$ 2.7	$ 11.5
Goodwill [b]					
DPLER Reporting unit	$ 135.8	$ —	$ —	$ —	$ 135.8

$ 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

(a) See Note 15 – Fixed-asset Impairment for further information
(b) See Note 7 – Goodwill and Other Intangible Assets for further information

Note 6 – 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 if they qualify under FASC 815 for accounting purposes.

At December 31, 2015, **DPL** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	**Not designated**	**MWh**	**10.2**	**—**	**10.2**
Forward Power Contracts	**Designated**	**MWh**	**1,676.7**	**(7,795.8)**	**(6,119.1)**
Forward Power Contracts	**Not designated**	**MWh**	**5,049.9**	**(1,663.0)**	**3,386.9**

At December 31, 2014, **DPL** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Not designated	MWh	10.5	—	10.5
Heating Oil Futures	Not designated	Gallons	378.0	—	378.0
Natural Gas Futures	Not designated	Dths	200.0	—	200.0
Forward Power Contracts	Designated	MWh	175.0	(2,991.0)	(2,816.0)
Forward Power Contracts	Not designated	MWh	1,725.2	(2,707.8)	(982.6)

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.

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 tables set forth the gains / (losses) recognized in AOCI and earnings related to the effective portion of derivative instruments and the gains / (losses) recognized in earnings related to the ineffective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the periods indicated:

	Years ended December 31,					
	2015		2014		2013	
$ in millions (net of tax)	**Power**	**Interest Rate Hedges**	Power	Interest Rate Hedges	Power	Interest Rate Hedges
Beginning accumulated derivative gain / (loss) in AOCI	**$ 0.2**	**$ 18.3**	$ 1.4	$ 19.2	$ (3.0)	$ 0.5
Net gains / (losses) associated with current period hedging transactions	**18.2**	**—**	(19.0)	—	1.0	18.7
Net gains / (losses) reclassified to earnings:						
Interest Expense	**—**	**(0.8)**	—	(0.9)	—	—
Revenues	**(12.0)**	**—**	18.3	—	2.1	—
Purchased Power	**2.8**	**—**	(0.5)	—	1.3	—
Ending accumulated derivative gain in AOCI	**$ 9.2**	**$ 17.5**	$ 0.2	$ 18.3	$ 1.4	$ 19.2
Net gains / (losses) associated with the ineffective portion of the hedging transaction						
Interest Expense	**$ —**	**$ —**	$ —	$ —	$ —	$ 0.8
Portion expected to be reclassified to earnings in the next twelve months [(a)]	**$ 5.9**	**$ (0.8)**				
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**36**	**—**				

(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.

Derivatives not designated as hedges

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, 2015, 2014 and 2013:

	Year ended December 31, 2015				
$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized loss	**$ 0.4**	**$ 0.3**	**$ (6.4)**	**$ 0.1**	**$ (5.6)**
Realized gain / (loss)	**(0.3)**	**(0.2)**	**(9.8)**	**(0.1)**	**(10.4)**
Total	**$ 0.1**	**$ 0.1**	**$ (16.2)**	**$ —**	**$ (16.0)**
Recorded on Balance Sheet:					
Regulatory asset	**$ 0.1**	**$ —**	**$ —**	**$ —**	**$ 0.1**
Recorded in Income Statement: gain / (loss)					
Purchased Power	**—**	**0.1**	**(43.6)**	**—**	**(43.5)**
Revenue	**—**	**—**	**27.4**	**—**	**27.4**
Total	**$ 0.1**	**$ 0.1**	**$ (16.2)**	**$ —**	**$ (16.0)**

	Year ended December 31, 2014				
$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain	$ (0.6)	$ (0.8)	$ (1.5)	$ (0.1)	$ (3.0)
Realized gain	(0.1)	0.7	(3.6)	(0.1)	(3.1)
Total	$ (0.7)	$ (0.1)	$ (5.1)	$ (0.2)	$ (6.1)
Recorded on Balance Sheet:					
Regulatory asset	$ (0.1)	$ —	$ —	$ —	$ (0.1)
Recorded in Income Statement: gain / (loss)					
Purchased Power	—	(0.1)	(5.1)	(0.2)	(5.4)
Fuel	(0.6)	—	—	—	(0.6)
Total	$ (0.7)	$ (0.1)	$ (5.1)	$ (0.2)	$ (6.1)

$ in millions	Year ended December 31, 2013 Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments				
Change in unrealized gain / (loss)	$ —	$ 0.3	$ 0.6	$ 0.9
Realized gain / (loss)	0.1	1.2	1.1	2.4
Total	$ 0.1	$ 1.5	$ 1.7	$ 3.3
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

The following tables show the fair value, balance sheet classification and hedging designation of **DPL's** derivative instruments at December 31, 2015 and 2014.

Fair Values of Derivative Instruments

December 31, 2015

			Gross Amounts Not Offset in the Consolidated Balance Sheets		
$ in millions	Hedging Designation	Gross Fair Value as presented in the Consolidated Balance Sheets [(a)]	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	Designated	$ 16.2	$ (7.1)	$ —	$ 9.1
Forward power contracts	Not designated	7.3	(5.5)	—	1.8
FTRs	Not designated	0.2	(0.2)	—	—
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Designated	3.0	(2.4)	—	0.6
Forward power contracts	Not designated	4.0	(2.7)	—	1.3
Total assets		$ 30.7	$ (17.9)	$ —	$ 12.8
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Designated	$ 7.1	$ (7.1)	$ —	$ —
Forward power contracts	Not designated	14.5	(5.5)	(8.0)	1.0
FTRs	Not designated	0.5	(0.2)	—	0.3
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Designated	2.7	(2.4)	—	0.3
Forward power contracts	Not designated	2.7	(2.7)	—	—
Total liabilities		$ 27.5	$ (17.9)	$ (8.0)	$ 1.6

(a) Includes credit valuation adjustment.

Fair Values of Derivative Instruments
December 31, 2014

$ 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	Designated	$ 5.6	$ (2.0)	$ —	$ 3.6
Forward power contracts	Not designated	5.5	(3.4)	—	2.1
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Designated	0.3	(0.3)	—	—
Forward power contracts	Not designated	3.5	(0.9)	—	2.6
Total assets		$ 14.9	$ (6.6)	$ —	$ 8.3
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Designated	$ 2.1	$ (2.0)	$ —	$ 0.1
Forward power contracts	Not designated	7.5	(3.4)	(4.1)	—
FTRs	Not designated	0.6	—	—	0.6
Heating Oil Futures	Not designated	0.4	—	(0.4)	—
Natural Gas	Not designated	0.1	—	(0.1)	—
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Designated	0.6	(0.3)	(0.3)	—
Forward power contracts	Not designated	0.9	(0.9)	—	—
Total liabilities		$ 12.2	$ (6.6)	$ (4.9)	$ 0.7

(a) Includes credit valuation adjustment.

As of December 31, 2014, the above table includes Forward power contracts in a short-term asset position of $11.1 million. This table does not include a short-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.

Credit risk-related contingent features

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. 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, 2015 is $27.5 million. This amount is offset by $8.0 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 $17.9 million. Since our debt is below investment grade, we could have to post collateral for the remaining $1.6 million.

Note 7 – Goodwill and Other Intangible Assets

Goodwill

The following table summarizes the changes in Goodwill by reportable segment for the years ended December 31, 2015, 2014 and 2013:

$ in millions	DP&L Reporting Unit	DPLER Reporting Unit	Total
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
Goodwill impairments during 2014	$ —	$ (135.8)	$ (135.8)
Balance at December 31, 2014			
Goodwill	$ 2,440.5	$ 135.8	$ 2,576.3
Accumulated impairment losses	(2,123.5)	(135.8)	(2,259.3)
Net balance at December 31, 2014	$ 317.0	$ —	$ 317.0
Goodwill impairments during 2015	$ (317.0)	$ —	$ (317.0)
Balance at December 31, 2015			
Goodwill	$ 2,440.5	$ 135.8	$ 2,576.3
Accumulated impairment losses	(2,440.5)	(135.8)	(2,576.3)
Net balance at December 31, 2015	$ —	$ —	$ —

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 included **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. Goodwill represented the value assigned at the Merger date, as adjusted for subsequent changes in the purchase price allocation, less recognized impairments.

DPLER Reporting Unit

During the first quarter of 2014, we performed an interim impairment test on the $135.8 million in goodwill at our DPLER reporting unit. During the second quarter of 2014, we finalized the work to determine the implied fair value for the DPLER reporting unit. There were no further adjustments to the full impairment of $135.8 million recognized in the first quarter. DPLER was sold on January 1, 2016 and is presented in discontinued operations on the Consolidated Statement of Operations. See Note 16 – Discontinued Operations for additional information.

DP&L Reporting Unit

During the fourth quarter of 2015, **DPL** performed its annual goodwill impairment test and recognized a goodwill impairment at its DP&L reporting unit of $317.0 million. The reporting unit failed Step 1 as its fair value was less than its carrying amount, which was primarily due to a decrease forecasted in dark spreads that were driven by decreases in projected forward power prices, and lower than expected revenues from the CP product. 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 forward commodity price curves, expected revenues from the new CP product, and planned environmental expenditures. In Step 2, goodwill was determined to have no implied fair value after the hypothetical purchase price allocation under the accounting guidance for business combinations; therefore, a full impairment of the remaining goodwill balance of $317.0 million was recognized. The goodwill associated with the Merger is not deductible for tax purposes. Accordingly, there is no financial statement tax benefit related to the impairment.

During the fourth quarter of 2013, **DPL** performed its annual goodwill impairment test and recognized a goodwill impairment at its DP&L reporting unit 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.

The goodwill associated with the Merger is not deductible for tax purposes. Accordingly, there is no cash or financial statement tax benefit related to the impairment.

Note 8 – Debt

Long-term debt

$ in millions	Interest Rate	Maturity	December 31, 2015	December 31, 2014
First mortgage bonds	1.875%	2016	$ 445.0	$ 445.0
Pollution control series	4.7%	2028	—	35.3
Pollution control series	4.8%	2034	—	179.1
Pollution control series	4.8%	2036	100.0	100.0
Pollution control series - rates from: 0.02% - 0.12% and 0.04% - 0.15% (a)		2040	—	100.0
Pollution control series - rates from: 1.13% - 1.17%		2020	200.0	—
U.S. Government note	4.2%	2061	18.1	18.2
Unamortized debt discounts and premiums, net			(3.6)	(2.8)
Total long-term debt at subsidiary			759.5	874.8
Bank term loan - rates from: 2.44% - 2.67% and 2.41% - 2.44% (a)		2020	125.0	160.0
Senior unsecured bonds	6.5%	2016	130.0	130.0
Senior unsecured bonds	6.75%	2019	200.0	200.0
Senior unsecured bonds	7.25%	2021	780.0	780.0
Note to DPL Capital Trust II (b)	8.125%	2031	15.6	15.6
Unamortized debt discounts and premiums, net			(0.7)	(0.7)
Subtotal			$ 2,009.4	$ 2,159.7
Less: current portion			(574.9)	(20.1)
Total			1,434.5	2,139.6

(a) Range of interest rates for the years ended December 31, 2015 and 2014, respectively.
(b) Note payable to related party. See Note 13 – Related Party Transactions for additional information.

At December 31, 2015, maturities of long-term debt are summarized as follows:

Due within the years ending December 31, $ in millions		
2016	$	575.1
2017		25.1
2018		25.1
2019		225.2
2020		250.2
Thereafter		913.0
		2,013.7
Unamortized discounts and premiums, net		(4.3)
Total long-term debt	$	2,009.4

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

Significant transactions
On July 1, 2015, the $35.3 million of **DP&L's** 4.7% pollution control bonds due January 2028 and $41.3 million of **DP&L's** 4.8% pollution control bonds due January of 2034 were called at par and were redeemed with cash.

On July 31, 2015, **DP&L** refinanced its revolving credit facility. The new facility has a $175.0 million borrowing limit, with a $50.0 million letter of credit sublimit, a feature that provides **DP&L** the ability to increase the size of the facility by an additional $100.0 million and maturity date of July 2020. At December 31, 2015, there were two letters of credit in the amount of $1.4 million outstanding, with the remaining $173.6 million available to **DP&L**. Fees associated with this revolving credit facility were not material during the years ended December 31, 2015 or 2014. Prior to refinancing the facility on July 31, 2015, this facility had a $300.0 million borrowing limit, a five-year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature that provided **DP&L** the ability to increase the size of the facility by an additional $100.0 million.

On August 3, 2015, **DP&L** called $100.0 million of variable rate pollution control bonds due November 2040, terminated the amended standby letter of credit facilities that supported these pollution control bonds, and called $137.8 million of 4.8% pollution control bonds due January of 2034. **DP&L** also used cash to redeem $37.8 million of these bonds and refinanced the $200.0 million balance, with new variable interest rate pollution control bonds secured by first mortgage bonds in an equivalent amount. In connection with the sale of the new pollution control bonds, **DP&L** entered into a certain Bond Purchase and Covenants Agreement, dated as of August 1, 2015, containing representations, warranties, covenants and defaults consistent with those contained in the revolving credit facilities loan documents of **DP&L**.

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. Substantially concurrent with this transaction, **DP&L** redeemed $470.0 million of previously outstanding first mortgage bonds.

On July 31, 2015, **DPL** refinanced its revolving credit facility. The new facility has a total size of $205.0 million, a $200.0 million letter of credit sublimit, a feature that provides **DPL** the ability, under certain circumstances, to increase the size of the facility by an additional $95.0 million and a maturity date of July 2020. **DPL's** new credit facility also has a springing maturity feature providing that if, before July 1, 2019, **DPL** has not refinanced its senior unsecured bonds due October 2019 to have a maturity date that is at least six months later than July 31, 2020, then the maturity of this facility shall be July 1, 2019. This facility is secured by a pledge of common stock that **DPL** owns in **DP&L**, limited to the amount permitted to be pledged under certain Indentures dated October 3, 2011 and October 6, 2014 between **DPL** and Wells Fargo Bank, NA and U.S. Bank National Association, respectively, as Trustee and a limited recourse guarantee by DPLE secured by mortgages on assets of DPLE. At December 31, 2015, there were two letters of credit in the amount of $3.0 million outstanding under this facility, with the remaining

$202.0 million of the revolving credit facility remaining available to **DPL**. Fees associated with this facility were not material during the years ended December 31, 2015 or 2014.

Prior to refinancing the facility on July 31, 2015, this facility was unsecured and had a borrowing limit of $100.0 million with a $100.0 million letter of credit sublimit, was able to be increased in size by **DPL** by an additional $50.0 million and had a five-year term expiring on May 10, 2018; with a springing maturity, meaning that if **DPL** had not refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then the maturity of this facility would have been July 15, 2016.

Also on July 31, 2015, **DPL** refinanced its term loan, paying down the outstanding amount of $160.0 million using proceeds from the new term loan of $125.0 million and a combination of cash on hand and draws on short term credit facilities. The new term loan extends the term to July of 2020, pushing back required principal payments to 2017, and providing a mechanism for **DPL** to request additional term loans to refinance existing indebtedness. The new term loan has a springing maturity feature providing that if, before July 1, 2019, **DPL** has not refinanced its senior unsecured bonds due October 2019 to have a maturity date that is at least six months later than July 31, 2020, then the maturity of this facility shall be July 1, 2019. This facility is secured by a pledge of common stock that **DPL** owns in **DP&L**, limited to the amount permitted to be pledged under certain Indentures dated October 3, 2011 and October 6, 2014 between **DPL** and Wells Fargo Bank, NA and U.S. Bank National Association, respectively, as Trustee and a limited recourse guarantee by DPLE secured by mortgages on assets of DPLE. The new term loan has a springing maturity feature providing that if, before July 1, 2019, **DPL** has not refinanced its senior unsecured bonds due October 2019 to have a maturity date that is at least six months later than July 31, 2020, then the maturity of this facility shall be July 1, 2019.

In October 2014, **DPL** repaid $5.0 million of the note due to Capital Trust II, which used the funds to repurchase securities in the open market at a slight premium. Subsequent to repurchasing these securities, Capital Trust II immediately retired them.

In connection with the closing of the Merger, **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 $20.0 million of both the first and second tranche of senior unsecured notes and immediately retired them.

In October 2014, **DPL** closed a $200.0 million issuance of senior unsecured bonds. These new bonds were priced at 6.75% and mature on October 1, 2019. Proceeds from the issuance, in addition to a draw on the **DPL** revolving line of credit and cash on hand, were used to settle a tender offer for $300.0 million of the 6.50% senior unsecured notes maturing October 15, 2016. After this transaction, the DPL Inc. 6.5% Senior Notes due 2016 had an outstanding principle balance of $130.0 million

On January 6, 2016, **DPL** issued a Notice of Partial Redemption to the Trustee (Wells Fargo Bank N.A.) on the DPL Inc. 6.5% Senior Notes due 2016 (a component of the Dolphin Subsidiary II, Inc. debt). **DPL** notified the trustee that it was calling $73.0 million of the $130.0 million outstanding principal amount of these notes. The record date of this redemption was January 21, 2016, and the redemption date was February 5, 2016. These bonds were redeemed at par plus accrued interest and a make-whole premium of $2.4 million.

Debt covenants and restrictions

DP&L's unsecured revolving credit agreement and Bond Purchase and Covenants Agreement (financing document entered into in connection with the sale of the new $200.0 million of variable rate pollution control bonds, dated as of August 1, 2015, containing representations, warranties, covenants and defaults consistent with those contained in the revolving credit facilities loan documents of **DP&L**) have two financial covenants. The first measures Total Debt to Total Capitalization and 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. The second financial covenant measures EBITDA to Interest Expense. 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.

DPL's revolving credit agreement and 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.

As of December 31, 2015, **DP&L** and **DPL** were in compliance with all debt covenants, including the financial covenants described above.

DP&L does not have any meaningful restrictions in its debt financing documents prohibiting dividends to its parent, **DPL**. **DPL's** secured revolving credit agreement, secured term loan, and senior unsecured notes due 2019 restrict dividend payments from **DPL** to AES, such that **DPL** cannot make dividend payments unless at the time of, and/or as a result of, the distribution, **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, 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 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, 2015, **DPL's** leverage ratio was at 1.03 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, as of December 31, 2015, **DPL** was prohibited under each of these agreements from making a distribution to its shareholder or making a loan to any of its affiliates (other than its subsidiaries).

Note 9 – Income Taxes

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

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Computation of tax expense			
Federal income tax expense / (benefit)[(a)]	**$ (81.0)**	$ 25.4	$ (71.7)
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**(0.1)**	0.8	1.1
Depreciation of AFUDC - Equity	**(3.5)**	(3.4)	(3.2)
Investment tax credit amortized	**(0.5)**	(0.5)	(0.5)
Section 199 - domestic production deduction	**(4.1)**	(1.1)	(4.1)
Non-deductible goodwill impairment	**111.0**	—	107.2
Accrual (settlement) for open tax years	—	(6.6)	(8.8)
Other, net [(b)]	**(1.8)**	0.8	(0.2)
Total tax expense	**$ 20.0**	$ 15.4	$ 19.8
Components of tax expense			
Federal - current	**$ 30.1**	$ (5.2)	$ (2.5)
State and Local - current	**0.8**	0.4	—
Total current	**30.9**	(4.8)	(2.5)
Federal - deferred	**(9.9)**	19.6	20.6
State and local - deferred	**(1.0)**	0.6	1.7
Total deferred	**(10.9)**	20.2	22.3
Total tax expense	**$ 20.0**	$ 15.4	$ 19.8

Effective and Statutory Rate Reconciliation

The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to **DPL's** effective tax rate, as a percentage of income from continuing operations before taxes for the years ended December 31, 2015, 2014 and 2013:

	Years ended December 31,		
	2015	2014	2013
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
State taxes, net of Federal tax benefit	**0.1 %**	1.1 %	(0.6)%
AFUDC - Equity	**1.5 %**	(4.7)%	1.5 %
Amortization of investment tax credits	**0.2 %**	(0.7)%	0.2 %
Section 199 - domestic production deduction	**1.8 %**	(1.6)%	2.0 %
Non-deductible goodwill impairment	**(48.0)%**	— %	(52.1)%
Other, net	**0.8 %**	(7.9)%	4.3 %
Effective tax rate	**(8.6)%**	21.2 %	(9.7)%

Deferred Income Taxes

Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and (b) operating loss carryforwards. These items are stated at the enacted tax rates that are expected to be in effect when taxes are actually paid or recovered. Investment tax credits related to utility property have been deferred and are being amortized over the estimated useful lives of the related property.

Components of Deferred Tax Assets and Liabilities

	December 31,	
$ in millions	**2015**	2014
Net non-current Assets / (Liabilities)		
Depreciation / property basis	**$ (539.8)**	$ (548.2)
Income taxes recoverable	**(12.0)**	(14.8)
Regulatory assets	**(10.6)**	(18.0)
Investment tax credit	**0.7**	1.5
Compensation and employee benefits	**3.1**	3.2
Intangibles	**(8.4)**	(7.0)
Long-term debt	**(1.1)**	(1.5)
Other (c)	**(0.6)**	(2.5)
Net non-current liabilities	**$ (568.7)**	$ (587.3)
Net current Assets / (Liabilities) (d)		
Other	**$ —**	$ 1.1
Net current assets / (liabilities)	**$ —**	$ 1.1

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

(b) Includes expense of $0.2 million, $0.4 million and $0.0 million in the years ended December 31, 2015, 2014, and 2013, respectively, of income tax related to adjustments from prior years.

(c) The Other non-current liabilities caption includes deferred tax assets of $26.0 million in 2015 and $27.1 million in 2014 related to state and local tax net operating loss carryforwards, net of related valuation allowances of $17.2 million in 2015 and $18.9 million in 2014. These net operating loss carryforwards expire from 2016 to 2030.

(d) Amounts are included within Other prepayments and current assets and Other current liabilities on the Consolidated Balance Sheet of **DPL** at December 31, 2014.

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.

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Tax expense / (benefit)	**$ 6.3**	$ (9.1)	$ 15.4

Uncertain Tax Positions
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 December 31, 2013	$ 8.8
Calendar 2014	
Tax positions taken during prior period	2.8
Lapse of Statute of Limitations	(8.6)
Balance at December 31, 2014	3.0
Calendar 2015	
Tax positions taken during prior period	—
Lapse of Statute of Limitations	—
Balance at December 31, 2015	$ 3.0

Of the December 31, 2015 balance of unrecognized tax benefits, $0.9 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 amounts accrued as well as the expense / (benefit) recorded were not material for the years ended December 31, 2015, 2014 and 2013.

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 statute 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 in 2013.

Note 10 – Benefit Plans

Defined contribution plans
DP&L sponsors two defined contribution plans. One is for non-union employees (the management plan) and one is for collective bargaining employees (the union plan). Both plans are qualified under Section 401 of the Internal Revenue Code.

Certain non-union employees become eligible to participate in the management plan on the first day of the month following the first full calendar month of employment; provided the employee worked at least 160 hours in that calendar month. Union employees become eligible to participate in the union plan on the first day of the first month following 30 days of employment. Effective January 1, 2016, employees in both plans are eligible to participate upon date of hire.

Participants may elect to contribute up to 85% of eligible compensation to their plan. Non-union participant contributions are matched 100% on the first 1% of eligible compensation and 50% on the next 5% of eligible compensation and they are fully vested in their employer contributions after 2 years of service. Union participant contributions are matched 150% but are capped at $2,100 for 2015 and they are fully vested in their employer contributions after 3 years of service. All participants are fully vested in their own contributions.

For the years ended December 31, 2015, 2014 and 2013, **DP&L's** contributions to all defined contribution plans were $4.8 million, $4.7 million and $4.8 million per year, respectively.

Defined benefit plans
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 January 1, 2014, the Service Company began providing services including accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including among other companies, **DPL** and **DP&L**. 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 has an immaterial unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. We also include our net liability to our partners related to our share of their pension costs within Pension, retiree and other benefits on our Consolidated Balance Sheets.

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.

Postretirement benefits
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.

The following tables set forth the changes in our pension and postemployment benefit plans' obligations and assets recorded on the balance sheets at December 31, 2015 and 2014. The amounts presented in the following tables for pension obligations 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 obligations include both health and life insurance benefits.

$ in millions	Pension	
	Years ended December 31,	
	2015	2014
Change in benefit obligation		
Benefit obligation at January 1	**$ 443.8**	$ 370.5
Service cost	**7.1**	5.9
Interest cost	**17.3**	17.5
Plan amendments	**—**	6.8
Actuarial (gain) / loss	**(34.5)**	67.3
Benefits paid	**(22.9)**	(24.2)
Benefit obligation at December 31	**410.8**	443.8
Change in plan assets		
Fair value of plan assets at January 1	**371.7**	349.1
Actual return on plan assets	**(8.8)**	46.4
Contributions to plan assets	**5.4**	0.4
Benefits paid	**(22.9)**	(24.2)
Fair value of plan assets at December 31	**345.4**	371.7
Funded status of plan	**$ (65.4)**	$ (72.1)

	December 31,	
Amounts recognized in the Balance sheets	**2015**	2014
Current liabilities	**$ (0.4)**	$ (0.4)
Non-current liabilities	**(65.0)**	(71.7)
Net liability at December 31,	**$ (65.4)**	$ (72.1)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax		
Components:		
Prior service cost	**$ 12.0**	$ 14.1
Net actuarial loss	**94.7**	103.4
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 106.7**	$ 117.5
Recorded as:		
Regulatory asset	**$ 91.1**	$ 99.0
Regulatory liability	**—**	—
Accumulated other comprehensive income	**15.6**	18.5
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 106.7**	$ 117.5

$ in millions	Postretirement	
	Years ended December 31,	
	2015	2014
Change in benefit obligation		
Benefit obligation at beginning of period	**$ 19.6**	$ 19.7
Service cost	**0.2**	0.2
Interest cost	**0.6**	0.8
Actuarial (gain) / loss	**(1.1)**	0.2
Benefits paid	**(1.5)**	(1.3)
Benefit obligation at end of period	**17.8**	19.6
Change in plan assets		
Fair value of plan assets at beginning of period	**3.3**	3.7
Contributions to plan assets	**1.0**	0.9
Benefits paid	**(1.5)**	(1.3)
Fair value of plan assets at end of period	**2.8**	3.3
Funded status of plan	**$ (15.0)**	$ (16.3)

	December 31,	
	2015	2014
Amounts recognized in the Balance sheets		
Current liabilities	**$ (0.4)**	$ (0.5)
Non-current liabilities	**(14.6)**	(15.8)
Net liability at December 31,	**$ (15.0)**	$ (16.3)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax		
Components:		
Prior service cost	**$ 0.3**	$ 0.4
Net actuarial gain	**(5.5)**	(5.0)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ (5.2)**	$ (4.6)
Recorded as:		
Regulatory asset	**$ 0.3**	$ 0.4
Regulatory liability	**(5.1)**	(4.8)
Accumulated other comprehensive income	**(0.4)**	(0.2)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ (5.2)**	$ (4.6)

The accumulated benefit obligation for our defined benefit pension plans was $401.2 million and $431.0 million at December 31, 2015 and 2014, respectively.

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

Net Periodic Benefit Cost - Pension

$ in millions	Years ended December 31, 2015	2014	2013
Service cost	**$ 7.1**	$ 5.9	$ 7.2
Interest cost	**17.3**	17.5	15.6
Expected return on assets [(a)]	**(22.6)**	(22.9)	(23.3)
Amortization of unrecognized:			
Actuarial gain	**5.8**	3.4	4.9
Prior service cost	**2.0**	1.5	1.5
Net periodic benefit cost	**$ 9.6**	$ 5.4	$ 5.9

Net Periodic Benefit Cost - Postretirement

$ in millions	Years ended December 31, 2015	2014	2013
Service cost	**$ 0.2**	$ 0.2	$ 0.2
Interest cost	**0.6**	0.8	0.8
Expected return on assets [(a)]	**(0.1)**	(0.2)	(0.1)
Amortization of unrecognized:			
Actuarial loss	**(0.6)**	(0.6)	(0.5)
Prior service cost	**0.1**	—	—
Net periodic benefit cost	**$ 0.2**	$ 0.2	$ 0.4

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, 2015	2014	2013
Net actuarial loss / (gain)	**$ (3.0)**	$ 43.8	$ (12.0)
Prior service cost	**—**	6.8	—
Reversal of amortization item:			
Net actuarial loss	**(5.8)**	(3.4)	(4.9)
Prior service cost	**(2.0)**	(1.5)	(1.5)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (10.8)**	$ 45.7	$ (18.4)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (1.2)**	$ 51.1	$ (12.5)

Postretirement

$ in millions	2015	2014	2013
	Years ended December 31,		
Net actuarial loss / (gain)	$ **(1.1)**	$ 0.4	$ (2.0)
Reversal of amortization item:			
Net actuarial gain	**0.6**	0.6	0.5
Prior service cost	$ **(0.1)**	$ —	$ —
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **(0.6)**	$ 1.0	$ (1.5)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **(0.4)**	$ 1.2	$ (1.1)

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2016 are:

$ in millions	Pension	Postretirement
Actuarial gain / (loss)	$ 4.3	$ (0.6)
Prior service cost	$ 1.9	$ 0.1

Assumptions
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.

At December 31, 2015, we are maintaining our long term rate of return assumption of 6.50% for pension plan assets. In addition, we are decreasing our long-term rate of return assumption to 3.90% from 4.50% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our long-term portfolio mixes. Also, at December 31, 2015, we have increased our assumed discount rate to 4.49% from 4.02% for pension and to 4.10% from 3.71% for postemployment benefits expense to reflect current duration-based yield curve discount rates. A one percent increase in the rate of return assumption for pension would result in a decrease in pension expense of approximately $3.5 million. A one percent decrease in the rate of return assumption for pension would result in an increase in pension expense of approximately $3.5 million. A 25 basis point increase in the discount rate for pension would result in a decrease of approximately $0.2 million to 2016 pension expense. A 25 basis point decrease in the discount rate for pension would result in an increase of approximately $0.3 million to 2016 pension expense. A one percent change in the assumed health care cost trend rate would affect postemployment benefit costs by less than $1.0 million.

In determining the discount rate to use for valuing liabilities, we used a market yield curve on high-quality fixed income investments as of December 31, 2015. We project the expected benefit payments under the plan based on participant data and based on certain assumptions concerning mortality, retirement rates, termination rates, etc. The expected benefit payments for each year are then discounted back to the measurement date using the appropriate spot rate for each half-year from the yield curve, thereby obtaining a present value of all expected future benefit payments using the yield curve. Finally, an equivalent single discount rate is determined which produces a present value equal to the present value determined using the full yield curve.

Effective January 1, 2016, we will apply a disaggregated discount rate approach for determining service cost and interest cost for our defined benefit pension plans and postretirement plans. See Note 1 – Overview and Summary of Significant Accounting Policies for more information.

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.

The weighted average assumptions used to determine benefit obligations at December 31, 2015, 2014 and 2013 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2015	2014	2013	**2015**	2014	2013
Discount rate for obligations	**4.49%**	4.02%	4.86%	**4.10%**	3.71%	4.58%
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, 2015, 2014 and 2013 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2015	2014	2013	**2015**	2014	2013
Discount rate	**4.02%**	4.86%	4.04%	**3.81%**	4.51%	4.58%
Expected rate of return on plan assets	**6.50%**	6.75%	6.75%	**4.50%**	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, 2015, 2014 and 2013 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2015	2014	2013	**2015**	2014	2013
Pre - age 65						
Current health care cost trend rate	**6.97%**	7.75%	8.00%	**6.85%**	6.97%	7.75%
Year trend reaches ultimate	**2029**	2023	2019	**2036**	2029	2023
Post - age 65						
Current health care cost trend rate	**6.97%**	6.75%	7.50%	**6.85%**	6.97%	6.75%
Year trend reaches ultimate	**2029**	2021	2018	**2036**	2029	2021
Ultimate health care cost trend rate	**4.50%**	5.00%	5.00%	**4.50%**	4.50%	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	$ —
Benefit obligation	$ 0.8	$ (0.7)

Pension 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, as well as short-term tactical asset allocation guidelines, are determined by a Risk/Advisory Committee and approved by a Fiduciary Committee. These allocations take into account the Plan's long-term objectives. The long-term target allocations for plan assets are 18% – 38% for equity securities and 58% – 86% for fixed income securities. 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.

Tactically, the committees, on a short-term basis, will make asset allocations that are outside the long-term allocation guidelines. The short-term allocation positions are likely to not exceed one-year in duration. In addition to the equity and fixed income investments, the short-term allocation may also include a relatively small allocation to alternative investments. The plan currently has a small allocation to a core property fund, as well as a small allocation to a hedge fund.

Most of our Plan assets are measured using quoted, observable prices which are considered Level One inputs in the Fair Value Hierarchy. The Core property collective fund and the Common collective fund are measured using Level Two inputs that are quoted prices for identical assets in markets that are less active.

The following table summarizes our target pension plan allocation for 2015:

		Percentage of plan assets as of December 31,	
Asset category	Long-Term Mid-Point Target Allocation	2015	2014
Equity Securities	28%	17%	18%
Debt Securities	72%	67%	69%
Real Estate	—%	9%	7%
Other	—%	7%	6%

The fair values of our pension plan assets at December 31, 2015 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2015

Asset Category $ in millions	**Market Value at December 31, 2015**	**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	$ 9.2	$ 9.2	$ —	$ —
Large cap equity	20.2	20.2	—	—
International equity	18.2	18.2	—	—
Emerging markets equity	2.7	2.7	—	—
SIIT dynamic equity	10.0	10.0	—	—
Total equity securities	60.3	60.3	—	—
Debt securities [(b)]				
Emerging markets debt	6.3	6.3	—	—
High yield bond	6.3	6.3	—	—
Long duration fund	219.5	219.5	—	—
Total debt securities	232.1	232.1	—	—
Other investments [(c)]				
Core property collective fund	30.2	—	30.2	—
Common collective fund	22.8	—	22.8	—
Total other investments	53.0	—	53.0	—
Total pension plan assets	$ 345.4	$ 292.4	$ 53.0	$ —

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(b) This category includes investments in investment-grade fixed-income instruments, 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 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 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, 2014 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2014

Asset Category $ in millions	Market Value at December 31, 2014	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	$ 10.6	$ 10.6	$ —	$ —
Large cap equity	22.2	22.2	—	—
International equity	18.2	18.2	—	—
Emerging markets equity	2.8	2.8	—	—
SIIT dynamic equity	11.6	11.6	—	—
Total equity securities	65.4	65.4	—	—
Debt securities [(b)]				
Emerging markets debt	6.0	6.0	—	—
High yield bond	6.5	6.5	—	—
Long duration fund	242.7	242.7	—	—
Total debt securities	255.2	255.2	—	—
Cash and cash equivalents [(c)]				
Cash	1.6	1.6	—	—
Other investments [(d)]				
Core property collective fund	26.3	—	26.3	—
Common collective fund	23.2	—	23.2	—
Total other investments	49.5	—	49.5	—
Total pension plan assets	$ 371.7	$ 322.2	$ 49.5	$ —

(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, 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 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 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, 2015 by asset category are as follows:

Fair Value Measurements for Other Postemployment Benefit Plan Assets at December 31, 2015

Asset Category $ in millions	**Market Value at December 31, 2015**	**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)]	$ **2.8**	$ **2.8**	$ —	$ —

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

The fair values of our other postemployment benefit plan assets at December 31, 2014 by asset category are as follows:

Fair Value Measurements for Other Postemployment Benefit Plan Assets at December 31, 2014

Asset Category $ in millions	Market Value at December 31, 2014	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)]	$ 3.3	$ 3.3	$ —	$ —

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

Pension funding

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. We contributed $5.0 million, $0.0 million, and $0.0 million to the pension plan during the years ended December 31, 2015, 2014 and 2013, respectively.

We expect to make contributions of $0.4 million to our SERP in 2016 to cover benefit payments. We also expect to contribute $1.1 million to our other postemployment benefit plans in 2016 to cover benefit payments. We made contributions of $5.0 million to our pension plan during January 2016.

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 2015 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 112.54% and is estimated to be 112.54% until the 2016 status is certified in September 2016 for the 2016 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.

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
2016	$ 24.6	$ 1.7
2017	$ 25.2	$ 1.6
2018	$ 25.8	$ 1.5
2019	$ 26.3	$ 1.4
2020	$ 26.7	$ 1.4
2021 - 2025	$ 134.8	$ 5.7

Note 11 – Equity

Redeemable Preferred Stock of Subsidiary

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding at December 31, 2015 and 2014. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding at December 31, 2015 or 2014. The table below details the preferred shares outstanding at December 31, 2015:

		December 31, 2015 and 2014		Carrying Value [(a)] ($ in millions)	
	Preferred Stock Rate	Redemption price ($ per share)	Shares Outstanding	**December 31, 2015**	December 31, 2014
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 the Merger date plus cumulative accrued dividends, of which there were none at December 31, 2015 and 2014.

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, of which there were none at December 31, 2015. 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 Consolidated Balance Sheets as "Redeemable Preferred Stock" in a manner consistent with temporary equity.

Dividend Restrictions

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 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, at December 31, 2015, **DP&L's** retained earnings of $437.3 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 Operations.

Common Stock

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, 2015.

As described above, **DPL's** Amended Articles of Incorporation contain restrictions on **DPL's** ability to make dividends, distributions and affiliate loans (other than to its subsidiaries), including restrictions of making such dividends, distributions and loans if certain financial ratios exceed specified levels and **DPL's** senior long-term debt rating from a rating agency is below investment grade. As of December 31, 2015, **DPL's** leverage ratio was at 1.03

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, as of December 31, 2015, **DPL** was prohibited under its Articles of Incorporation from making a distribution to its shareholder or making a loan to any of its affiliates (other than its subsidiaries).

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 2015. 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 12 – Contractual Obligations, Commercial Commitments and Contingencies

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

At December 31, 2015, **DPL** had $17.3 million of guarantees on behalf of DPLE to third parties for future financial or performance assurance under such agreements. In addition, **DPL** had $1.9 million of guarantees on behalf of DPLER which were released in January 2016 as a result of the sale of DPLER. The guarantee arrangements entered into by **DPL** with these third parties cover present and future obligations of DPLE and present obligations of DPLER to such beneficiaries and are terminable at any time by **DPL** upon written notice to the beneficiaries. All guarantees on behalf of DPLER were terminated in January 2016. The carrying amount of obligations for commercial transactions covered by these guarantees and recorded in our Consolidated Balance Sheets was $0.5 million and $1.6 million at December 31, 2015 and 2014, respectively.

To date, **DPL** has not incurred any losses related to these guarantees 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.

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. At December 31, 2015, **DP&L** could be responsible for the repayment of 4.9%, or $74.5 million, of a $1,519.9 million debt obligation comprised of both fixed and variable rate securities with maturities between 2016 and 2040. This would only happen if this electric generation company defaulted on its debt payments. At December 31, 2015, 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, 2015, these include:

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DPL:					
Coal contracts (a)	374.2	186.9	187.3	—	—
Purchase orders and other contractual obligations	83.8	24.4	30.0	29.4	—

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

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. At December 31, 2015, 73% of our future committed coal obligations are with a single supplier. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Purchase orders and other contractual obligations:
At December 31, 2015, **DPL** had various other contractual obligations, including non-cancelable contracts, to purchase goods and services with various terms and expiration dates.

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, 2015, 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 SIPs) 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 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.

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 $0.9 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 or a loss cannot be reasonably estimated. 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.

Note 13 – Related Party Transactions

Service Company
In December 2013, an agreement was signed, effective January 1, 2014, whereby the Service Company began providing services including operations, accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including, among other companies, **DPL** and **DP&L**. The Service Company allocates the costs for these services based on cost drivers designed to result in

fair and equitable allocations. This includes ensuring that the regulated utilities served, including **DP&L**, are not subsidizing costs incurred for the benefit of other businesses.

The following table provides a summary of these transactions:

$ in millions	For the years ended December 31, 2015	2014
Transactions with the Service Company		
Charges for services provided	**$ 36.0**	$ 35.8
Charges to the Service Company	**$ 6.2**	$ 2.4
Transactions with the Service Company:	**At December 31, 2015**	At December 31, 2014
Net payable to the Service Company	**$ (0.5)**	$ (4.7)

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 $0.3 million and $0.3 million at December 31, 2015 and 2014, respectively, is included in Other deferred assets within Other noncurrent assets. **DPL** also has a note payable to the Trust amounting to $15.6 million and $15.6 million at December 31, 2015 and 2014, respectively, that was established upon the Trust's deconsolidation in 2003. See Note 8 – Debt 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.

Income taxes
AES files federal and state income tax returns which consolidate **DPL** and its subsidiaries. Under a tax sharing agreement with AES, **DPL** is responsible for the income taxes associated with its own taxable income and records the provision for income taxes using a separate return method. **DPL** had a net payable balance under this agreement of $50.5 million and $16.1 million as of December 31, 2015 and 2014, respectively, which is recorded in Accrued taxes on the accompanying Consolidated Balance Sheets.

Note 14 – Business Segments

DPL had two reportable segments consisting of the operations of two of its wholly-owned subsidiaries, **DP&L** (Utility segment) and **DPLER** (Competitive Retail segment which included DPLER's wholly-owned subsidiary, MC Squared). This is how we viewed our business and made decisions on how to allocate resources and evaluate performance.

The Competitive Retail segment, DPLER's competitive retail electric service business, was sold on January 1, 2016 (see Note 16 – Discontinued Operations). **DPL** now operates through one segment, the Utility segment. Segment disclosures for 2014 and 2013 have not been restated to show the competitive retail segment as a discontinued operation and therefore do not tie to the Statements of Operations.

The Utility segment is comprised of **DP&L's** electric generation, transmission and distribution businesses which generate and deliver electricity to residential, commercial, industrial and governmental customers. **DP&L** generates electricity at five coal-fired electric generating stations and distributes electricity to approximately 517,000 retail customers who are located in a 6,000 square mile area of West Central Ohio. **DP&L** also sold 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 its generation business is deemed competitive under Ohio law.

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 were based on fixed-price contracts for each customer; the price approximated market prices for wholesale power at the inception of each customer's contract. These agreements were terminated in connection with the sale of DPLER on January 1, 2016.

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. Certain shared and corporate costs are allocated among reporting segments.

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

$ in millions	Utility	Other	Adjustments and Eliminations	DPL Consolidated
Year ended December 31, 2015				
Revenues from external customers	$ 1,550.8	$ 62.0	$ —	$ 1,612.8
Intersegment revenues	1.5	4.2	(5.7)	—
Total revenues	1,552.3	66.2	(5.7)	1,612.8
Fuel	244.7	15.1	—	259.8
Purchased power	555.7	8.9	(2.0)	562.6
Gross margin *(a)*	$ 751.9	$ 42.2	$ (3.7)	$ 790.4
Depreciation and amortization	$ 138.2	$ (3.6)	$ —	$ 134.6
Goodwill impairment (Note 7)	$ —	$ 317.0	$ —	$ 317.0
Fixed asset impairment	$ —	$ —	$ —	$ —
Interest expense	$ 30.9	$ 87.6	$ (0.2)	$ 118.3
Income tax expense / (benefit)	$ 35.1	$ (15.1)	$ —	$ 20.0
Net income / (loss) from continuing operations	$ 106.4	$ (357.8)	$ —	$ (251.4)
Discontinued operations, net of tax	$ —	$ 12.4	$ —	$ 12.4
Net income / (loss)	$ 106.4	$ (345.4)	$ —	$ (239.0)
Cash capital expenditures	$ 127.0	$ 10.2	$ —	$ 137.2
Total assets (end of year) (b)	$ 3,365.8	$ 1,314.4	$ (1,339.4)	$ 3,340.8

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

(b) Includes assets held for sale related to the sale of DPLER.

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
Year ended December 31, 2014					
Revenues from external customers	$ 1,181.2	$ 533.6	$ 48.2	$ —	$ 1,763.0
Intersegment revenues	487.1	—	5.5	(492.6)	—
Total revenues	1,668.3	533.6	53.7	(492.6)	1,763.0
Fuel	314.9	—	(10.4)	—	304.5
Purchased power	582.4	491.8	7.5	(489.1)	592.6
Amortization of intangibles	—	—	1.2	—	1.2
Gross margin [(a)]	$ 771.0	$ 41.8	$ 55.4	$ (3.5)	$ 864.7
Depreciation and amortization	$ 144.8	$ 0.8	$ (5.8)	$ —	$ 139.8
Goodwill impairment (Note 7)	$ —	$ —	$ 135.8	$ —	$ 135.8
Fixed asset impairment	$ —	$ —	$ 11.5	$ —	$ 11.5
Interest expense	$ 33.9	$ 0.5	$ 92.9	$ (0.7)	$ 126.6
Income tax expense / (benefit)	$ 39.7	$ 2.0	$ (23.5)	$ —	$ 18.2
Net income / (loss)	$ 115.0	$ 3.2	$ (192.8)	$ —	$ (74.6)
Cash capital expenditures	$ 114.2	$ 2.5	$ 1.4	$ —	$ 118.1
Total assets (end of year)	$ 3,338.7	$ 94.9	$ 1,440.1	$ (1,295.9)	$ 3,577.8

(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.

$ 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 7)	$ —	$ —	$ 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.

Note 15 – Fixed-asset Impairment

	Years ended December 31,		
	2015	2014	2013
East Bend (**DP&L**)	$ —	$ 11.5	$ —
Conesville (**DP&L**)	—	—	26.2
Total fixed-asset impairment expense	$ —	$ 11.5	$ 26.2

East Bend (DP&L) - During the first quarter of 2014, **DPL** tested the recoverability of long-lived assets at East Bend, a 186 MW coal-fired plant in Kentucky jointly-owned by **DP&L**. Indications during that quarter that the fair value of the asset group was less than its carrying amount were determined to be impairment indicators given how narrowly these long-lived assets had passed the recoverability test during the fourth quarter of 2013. **DPL** performed a long-lived asset impairment test and determined that the carrying amount of the asset group was not recoverable. The East Bend asset group was determined to have a fair value of $2.7 million using the market approach. As a result, we recognized an asset impairment expense of $11.5 million. East Bend is reported in the Utility segment, however, this impairment is shown within Other in Note 14 – Business Segments due to acquisition adjustments at **DPL** which were not pushed down to the utility segment. In May 2014, an agreement was signed for the sale of **DP&L's** interest in the generating assets at East Bend. This transaction closed on December 30, 2014.

Conesville (DP&L) - During the fourth quarter of 2013, **DPL** tested the recoverability of the 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. **DPL** 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, **DPL** recognized an asset impairment expense of $26.2 million. Conesville is reported in the Utility segment.

Note 16 – Discontinued Operations

On January 1, 2016, **DPL** closed on the sale of DPLER, its competitive retail business. The sale agreement was signed on December 28, 2015 and **DPL** received $75.5 million of restricted cash on December 31, 2015 for the sale. This amount is shown as Restricted cash with the associated liability shown as "Deposit received on sale of DPLER" on the Balance Sheet as of December 31, 2015. As the cash received was restricted upon receipt, it is not included within the Statement of Cash Flows. Assets and liabilities related to DPLER have been reclassified to "Assets held for sale" and "Liabilities held for sale" in the December 31, 2015 and 2014 Balance Sheets. We expect to record a gain on this transaction of approximately $56.0 million, net of tax, in the first quarter of 2016. The gain includes the impact of deferred taxes and DPLER's liability to **DP&L** that transferred with the sale on January 1, 2016 but was eliminated in consolidation at December 31, 2015 and 2014. Deferred taxes and intercompany balances were not reclassified to held for sale.

Operating activities related to DPLER have been reclassified to "Discontinued operations" in the Statements of Operations for the years ended December 31, 2015, 2014 and 2013.

The following table summarizes the major categories of assets, liabilities at the dates indicated, and the revenues, cost of revenues, operating expenses and income tax of discontinued operations for the periods indicated:

$ in millions	December 31, 2015	December 31, 2014
Accounts receivable, net	$ 31.0	$ 64.4
Property, plant & equipment, net	4.6	4.9
Intangible assets, net	24.6	29.6
Other assets	2.0	2.9
Total assets of the disposal group classified as held for sale in the balance sheets	$ 62.2	$ 101.8
Accounts payable	$ 0.8	$ 14.8
Other liabilities	0.8	2.5
Total liabilities of the disposal group classified as held for sale in the balance sheets	$ 1.6	$ 17.3

	Years ended December 31, 2015	2014	2013
Revenues	$ 340.9	$ 533.6	$ 511.6
Cost of revenues	(307.0)	(493.0)	(466.8)
Operating expenses	(22.5)	(34.0)	(38.8)
Goodwill impairment	—	(135.8)	—
Profit / (loss) of discontinued operations before income taxes	11.4	(129.2)	6.0
Income tax benefit / (expense)	(1.0)	2.6	2.4
Income / (loss) on discontinued operations	$ 12.4	$ (131.8)	$ 3.6

DPLER purchased its power from **DP&L** during the periods presented. Prior to DPLER being presented as a discontinued operation, this purchased power and **DP&L's** corresponding wholesale revenue would have been eliminated in consolidation.

Cash flows related to discontinued operations are included in our Consolidated Statements of Cash Flows. Cash flows from operating activities for discontinued operations were $35.8 million, $29.6 million and $(7.7) million for the years ended December 31, 2015, 2014 and 2013, respectively. Cash flows from investing activities for discontinued operations were $0.5 million, $(2.2) million and $(2.0) million for the years ended December 31, 2015, 2014, and 2013, respectively. All cash generated from discontinued operations was paid to **DPL** through dividends for all years presented.

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, 2015 and 2014, and the related statements of operations, comprehensive income, cash flows, and shareholder's equity for each of the three years in the period ended December 31, 2015. Our audit also included the financial statement schedule "Schedule II - Valuation and Qualifying Accounts" for each of the three years in the period ended December 31, 2015. 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, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, 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.

February 23, 2016
Indianapolis, Indiana

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF OPERATIONS

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Revenues	**$ 1,552.3**	$ 1,668.3	$ 1,551.5
Cost of revenues:			
Fuel	**244.7**	314.9	362.5
Purchased power	**555.7**	582.4	381.9
Total cost of revenues	**800.4**	897.3	744.4
Gross margin	**751.9**	771.0	807.1
Operating expenses:			
Operation and maintenance	**350.5**	355.2	364.2
Depreciation and amortization	**138.2**	144.8	140.2
General taxes	**85.0**	85.7	74.3
Fixed asset impairment	**—**	—	86.0
Other	**0.4**	(3.5)	2.5
Total operating expenses	**574.1**	582.2	667.2
Operating income	**177.8**	188.8	139.9
Other income / (expense), net			
Investment income	**0.3**	0.9	2.0
Interest expense	**(30.9)**	(33.9)	(37.2)
Charge for early redemption of debt	**(5.0)**	—	—
Other deductions	**(0.7)**	(1.1)	(2.5)
Other expense, net	**(36.3)**	(34.1)	(37.7)
Earnings from operations before income tax	**141.5**	154.7	102.2
Income tax expense	**35.1**	39.7	18.6
Net income	**106.4**	115.0	83.6
Dividends on preferred stock	**0.9**	0.9	0.9
Earnings attributable to common stock	**$ 105.5**	$ 114.1	$ 82.7

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Net income	**$ 106.4**	$ 115.0	$ 83.6
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $0.1, $0.2 and $0.9 for each respective period	**(0.2)**	(0.3)	(1.6)
Reclassification to earnings, net of income tax benefit / (expense) of $0.0, ($0.2) and ($0.7) for each respective period	**—**	0.2	1.4
Total change in fair value of available-for-sale securities	**(0.2)**	(0.1)	(0.2)
Derivative activity:			
Change in derivative fair value, net of income tax benefit / (expense) of ($10.3), $10.5 and ($0.6) for each respective period	**18.2**	(18.8)	1.0
Reclassification of earnings, net of income tax benefit / (expense) of $5.6, ($11.5) and ($2.5) for each respective period	**(9.8)**	15.4	2.6
Total change in fair value of derivatives	**8.4**	(3.4)	3.6
Pension and postretirement activity:			
Prior service cost for the period, net of income tax benefit / (expense) of $0.0, $1.3 and ($0.2) for each respective period	**—**	(2.3)	0.5
Net loss for the period, net of income tax benefit / (expense) of ($1.0), $7.2 and ($1.9) for each respective period	**1.7**	(12.5)	4.3
Reclassification to earnings, net of income tax benefit / (expense) of ($1.9), ($1.5) and ($1.9) for each respective period	**3.7**	2.7	3.8
Total change in unfunded pension and postretirement obligation	**5.4**	(12.1)	8.6
Other comprehensive income / (loss)	**13.6**	(15.6)	12.0
Net comprehensive income	**$ 120.0**	$ 99.4	$ 95.6

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5.4	$ 5.4
Restricted cash	44.8	16.7
Accounts receivable, net (Note 2)	119.5	152.7
Inventories (Note 2)	108.0	99.0
Taxes applicable to subsequent years	79.2	75.4
Regulatory assets, current (Note 3)	14.4	44.2
Other prepayments and current assets	48.1	41.1
Total current assets	419.4	434.5
Property, plant and equipment:		
Property, plant and equipment	5,244.7	5,120.7
Less: Accumulated depreciation and amortization	(2,584.0)	(2,495.7)
	2,660.7	2,625.0
Construction work in process	78.0	75.4
Total net property, plant and equipment	2,738.7	2,700.4
Other non-current assets:		
Regulatory assets, non-current (Note 3)	179.9	167.5
Intangible assets, net of amortization (Note 1)	5.0	7.8
Other deferred assets	22.8	28.5
Total other non-current assets	207.7	203.8
Total Assets	$ 3,365.8	$ 3,338.7
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 7)	$ 444.9	$ 0.1
Short-term debt	35.0	—
Accounts payable	94.1	104.8
Accrued taxes	86.2	82.6
Accrued interest	4.1	9.8
Customer security deposits	15.1	34.5
Regulatory liabilities, current (Note 3)	24.4	4.4
Other current liabilities	51.0	44.8
Advance on contract termination	27.7	—
Total current liabilities	782.5	281.0
Non-current liabilities:		
Long-term debt (Note 7)	318.0	877.0
Deferred taxes (Note 8)	631.2	650.0
Taxes payable	82.1	78.4
Regulatory liabilities, non-current (Note 3)	127.0	124.1
Pension, retiree and other benefits (Note 9)	87.1	95.9
Unamortized investment tax credit	20.0	22.4
Other deferred credits	82.3	43.6
Total non-current liabilities	1,347.7	1,891.4
Redeemable preferred stock of subsidiary (Note 10)	22.9	22.9
Commitments and contingencies (Note 11)		
Common shareholder's equity:		
Common stock, par value of $0.01 per share 250,000,000 shares authorized, 41,172,173 shares issued and outstanding	0.4	0.4
Other paid-in capital	803.7	803.5
Accumulated other comprehensive loss	(28.7)	(42.3)
Retained earnings	437.3	381.8
Total common shareholder's equity	1,212.7	1,143.4
Total Liabilities and Shareholder's Equity	$ 3,365.8	$ 3,338.7

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF CASH FLOWS

$ in millions	Years ended December 31, 2015	2014	2013
Cash flows from operating activities:			
Net income	$ 106.4	$ 115.0	$ 83.6
Adjustments to reconcile Net income (loss) to Net cash from operating activities			
Depreciation and amortization	138.2	144.8	140.2
Amortization of deferred financing costs	2.9	3.1	1.5
Unrealized loss (gain) on derivatives	5.7	2.1	1.3
Deferred income taxes	(19.2)	7.5	(16.8)
Fixed-asset impairment	—	—	86.0
Loss / (Gain) on asset disposal	0.4	(3.5)	2.5
Changes in certain assets and liabilities:			
Accounts receivable	28.7	(7.1)	15.0
Inventories	(9.1)	(24.6)	27.2
Prepaid taxes	(1.3)	(1.1)	0.4
Taxes applicable to subsequent years	(3.7)	(6.9)	(1.8)
Deferred regulatory costs, net	21.8	5.4	7.8
Accounts payable	(5.8)	32.4	(5.9)
Accrued taxes payable	7.3	9.0	(9.1)
Accrued interest payable	(5.7)	0.1	(3.4)
Other current and deferred liabilities	(9.3)	(18.1)	5.9
Pension, retiree and other benefits	(0.7)	19.1	1.8
Unamortized investment tax credit	(2.4)	(2.5)	(2.5)
Other	2.5	(23.0)	1.6
Net cash from operating activities	256.7	251.7	335.3
Cash flows from investing activities:			
Capital expenditures	(127.0)	(114.2)	(122.1)
Decrease / (increase) in restricted cash	(0.3)	(3.7)	(2.3)
Purchase of renewable energy credits	(0.8)	(3.5)	(3.9)
Proceeds from sale of property	—	10.7	0.8
Insurance proceeds	5.2	0.9	14.2
Other investing activities, net	0.4	1.3	(1.2)
Net cash from investing activities	(122.5)	(108.5)	(114.5)
Cash flows from financing activities			
Dividends paid on common stock to parent	(50.0)	(159.0)	(190.0)
Dividends paid on preferred stock	(0.9)	(0.9)	(0.9)
Retirement of long-term debt	(314.4)	(0.1)	(470.1)
Issuance of long-term debt	200.0	—	445.0
Deferred financing costs	(3.9)	(0.7)	(10.4)
Borrowings from revolving credit facilities	50.0	—	—
Repayment of borrowings from revolving credit facilities	(50.0)	—	—
Borrowings from related party	35.0	15.0	—
Repayment of borrowings from related party	—	(15.0)	—
Net cash from financing activities	(134.2)	(160.7)	(226.4)
Cash and cash equivalents:			
Net increase / (decrease) in cash	—	(17.5)	(5.6)
Balance at beginning of period	5.4	22.9	28.5
Cash and cash equivalents at end of period	$ 5.4	$ 5.4	$ 22.9
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 27.5	$ 26.6	$ 41.5
Income taxes (refunded) / paid, net	$ 0.8	$ 0.7	$ (20.3)
Non-cash financing and investing activities:			
Accruals for capital expenditures	$ 16.9	$ 16.3	$ 14.7

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	$ 803.3	$ (38.7)	$ 534.1	$ 1,299.1
Year ended December 31, 2013						
Net comprehensive income				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
Year ended December 31, 2014						
Net comprehensive income				(15.6)	115.0	99.4
Common stock dividends					(159.0)	(159.0)
Preferred stock dividends					(0.9)	(0.9)
Other					(0.1)	(0.1)
Ending balance	41,172,173	0.4	803.5	(42.3)	381.8	1,143.4
Year ended December 31, 2015						
Net comprehensive income				**13.6**	**106.4**	**120.0**
Common stock dividends					**(50.0)**	**(50.0)**
Preferred stock dividends					**(0.9)**	**(0.9)**
Other			**0.2**			**0.2**
Ending balance	**41,172,173**	**$ 0.4**	**$ 803.7**	**$ (28.7)**	**$ 437.3**	**$ 1,212.7**

(a) $0.01 par value, 250,000,000 shares authorized.

See Notes to Financial Statements.

The Dayton Power and Light Company
Notes to Financial Statements
For the years ended December 31, 2015, 2014 and 2013

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 services are still regulated. **DP&L** has the exclusive right to provide such service to its approximately 517,000 customers located in West Central Ohio. Additionally, **DP&L** procures and provides 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 five coal-fired power stations. Beginning in 2014, **DP&L** no longer supplied 100% of the generation for SSO customers and starting January 2016, SSO is now 100% competitively bid. 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 sold electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

In accordance with the ESP Order, on December 30, 2013, **DP&L** filed an application with the PUCO stating its plan to transfer or sell its generation assets. On July 14, 2014, **DP&L** announced its decision to retain **DP&L's** generation assets. On September 17, 2014 the PUCO ordered that **DP&L's** application as amended and updated was approved. **DP&L** is required to sell or transfer its generation assets by January 1, 2017 and continues to look at multiple options to effectuate the separation, including transfer into an unregulated affiliate of **DPL** or through a sale.

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 1,189 people at January 31, 2016. Approximately 61% of all employees are under a collective bargaining agreement which expires on October 31, 2017.

Financial Statement Presentation

DP&L does not have any subsidiaries. **DP&L** has undivided ownership interests in five electric generating facilities and numerous transmission facilities. These undivided interests in jointly-owned facilities are accounted for on a pro rata basis in **DP&L's** Financial Statements.

Certain immaterial amounts from prior periods have been reclassified to conform to the current 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 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. The power sales and purchases within **DP&L's** service territory are reported on a net hourly basis as revenues or purchased power on our Statements 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. Amounts are written off when reasonable collections efforts have been exhausted.

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 $2.0 million, $1.5 million, and $1.5 million for the years ended December 31, 2015, 2014 and 2013, 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
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. For **DP&L's** generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 2.6% in 2015, 2.8% in 2014 and 4.4% in 2013. Depreciation was $132.7 million, $141.6 million and $136.5 million for the years ended December 31, 2015, 2014 and 2013, respectively.

During the fourth quarter of 2015, **DP&L** tested the recoverability of long-lived assets at certain generating stations. See Note 13 – Fixed-asset Impairment 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.

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. 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 **DP&L** 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 3 – Regulatory Assets and Liabilities for more information.

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 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. Emission allowances are amortized as they are used in our operations on a FIFO basis. Renewable energy credits are carried on a weighted average cost basis and amortized as they are used or retired.

Income Taxes
Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. We establish an allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. Our tax positions are evaluated under a more likely than not recognition threshold and measurement analysis before they are recognized for financial statement reporting. Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid within one year. Our policy for interest and penalties is to recognize interest and penalties as a component of the provision for income taxes in the Statement of Operations.

Income taxes payable, which are includable in allowable costs for ratemaking purposes in future years, are recorded as regulatory assets with a corresponding deferred tax liability. Investment tax credits that reduced federal income taxes in the years they arose have been deferred and are being amortized to income over the useful lives of the properties in accordance with regulatory treatment. See Note 3 – Regulatory Assets and Liabilities for additional information.

DPL and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. 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 – Income Taxes 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 bases for public equity security and fixed maturity investments are 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 and certain other taxes are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Operations. The amounts for the years ended December 31, 2015, 2014 and 2013 were $49.9 million, $50.8 million and $50.5 million, respectively.

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 includes restrictions imposed by agreements related to deposits held as collateral. At December 31, 2015, restricted cash also includes cash received in connection with the January 1, 2016 contract termination canceling **DP&L's** power sales contracts with DPLER. See Note 14 – Subsequent Event for additional information regarding this contract termination.

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, which results in changes in fair value being recorded within accumulated other comprehensive income, a component of shareholder's equity. 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 6 – Derivative Instruments and Hedging Activities 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 solely to us, other **DPL** subsidiaries and, in some cases, our partners in commonly-owned facilities we operate, for workers' compensation, general liability, and property damage on an ongoing basis. MVIC maintains an active run-off policy for directors' and officers' liability and fiduciary through their expiration in 2017, which may or may not be renewed at that time. **DP&L** is responsible for claim costs below certain coverage thresholds of MVIC and third party insurers for the insurance coverage noted above. **DP&L** has estimated liabilities for medical, life, and disability reserves for claims costs below certain coverage thresholds of MVIC and third-party providers. We recorded these additional insurance and claims costs of approximately $13.7 million and $15.6 million at December 31, 2015 and 2014, 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 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.

Pension and Postretirement Benefits
We recognize, in our Balance Sheets, an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in the funded status recognized in AOCI, except for those portions of our pension and postretirement obligations that can be recovered through future rates. All plan assets are recorded at fair value. We follow the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

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.

Effective January 1, 2016, we will apply a disaggregated discount rate approach for determining service cost and interest cost for its defined benefit pension plans and post-retirement plans. This approach is consistent with the requirements of ASC 715 and is considered to be preferential to the aggregated single rate discount approach, which has historically been used in the U.S., because it is more consistent with the philosophy of a full yield curve valuation.

The change in discount rate approach did not have an impact on the measurement of the benefit obligations at December 31, 2015, nor will it impact future remeasurements. This change in approach will impact the service cost and interest cost recorded in 2016 and future years. It will also impact the actuarial gains and losses recorded in future years, as well as the amortization thereof.

The expected 2016 service costs and interest costs included in Note 9 – Benefit Plans reflect the change in methodology described above. The impact of the change in approach on expected service costs in 2016 is shown below:

$ in millions	Expected 2016 Service Cost			Expected 2016 Interest Cost		
	Disaggregated rate approach	Aggregate rate approach	Impact of change	Disaggregated rate approach	Aggregate rate approach	Impact of change
Total Pension	$ 5.7	$ 6.1	$ (0.4)	$ 14.8	$ 17.9	$ (3.1)
Total Postretirement Benefits	$ 0.2	$ 0.2	$ —	$ 0.6	$ 0.7	$ (0.1)
Total	$ 5.9	$ 6.3	$ (0.4)	$ 15.4	$ 18.6	$ (3.2)

See Note 9 – Benefit Plans for more information.

Related Party Transactions
In the normal course of business, **DP&L** enters into transactions with other subsidiaries of **DPL** or AES.

See Note 12 – Related Party Transactions for additional information on Related Party Transactions.

New accounting pronouncements adopted

ASU No. 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes
Effective December 31, 2015, we prospectively adopted ASU No. 2015-17, which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. As a result, each jurisdiction will now only have one net noncurrent deferred tax asset or liability. The guidance does not change the existing requirement that only permits offsetting within a jurisdiction; that is, companies will remain prohibited from offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. Additionally, the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by the update. As we elected to apply this ASU prospectively, prior periods were not adjusted.

ASU No. 2015-13, Derivatives and Hedging (Topic 815):Derivatives and Hedging: Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Market
In August 2015, the FASB issued ASU No. 2015-13, which resolves the diversity in practice resulting from determining whether certain contracts qualify for the normal purchases and normal sales scope exception under ASC Topic 815, Derivatives and Hedging. This standard clarifies that entities would not be precluded from applying the normal purchases and normal sales exception to certain forward contracts that necessitate the transmission of electricity through, or delivery to a location within, a nodal energy market. The standard is effective upon issuance and should be applied prospectively. As we had designated qualifying contracts as normal purchase or normal sales, there was no impact on our financial statements upon adoption of this standard.

Accounting pronouncements issued but not yet effective

ASU No. 2016-01, Financial Instruments — Overall (Topic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities
In January 2016, the FASB issued ASU 2016-01, which was designed to improve the recognition and measurement of financial instruments through targeted changes to existing GAAP. The guidance requires equity investments (except those that are accounted for under the equity method of accounting or result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income; that entities use the exit price notion when measuring financial instrument fair values; that an entity separate presentation of financial assets and liabilities by measurement category and form of financial asset on the Balance Sheets or Notes to the financial statements; that an entity present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk (or "own credit") when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. Also, the standard eliminates the requirement for public entities to disclose the methods and significant assumptions used to estimate the fair value required to be disclosed for financial instruments measured at amortized cost on the Balance Sheets. The standard is effective beginning with interim periods starting after December 31, 2017 and cannot be applied early. We are currently evaluating the applicability and materiality of the standard, but we do not anticipate a material impact on our financial statements.

ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments
In September 2015, the FASB issued ASU 2015-16, which simplifies the measurement-period adjustments in business combinations. It eliminates the requirement that an acquirer in a business combination account for measurement-period adjustments retrospectively. An acquirer will recognize a measurement-period adjustment during the period in which it determines the amount of the adjustment. The standard is effective for public entities for annual reporting periods beginning after December 15, 2015, and interim periods therein. Early adoption is permitted for financial statements that have not been issued. The new guidance should be applied prospectively to adjustments to provisional amounts that occur after the effective date of this standard. We will adopt this standard on January 1, 2016, which is not expected to have a material impact on our

ASU No. 2015-03, Interest – Imputation of Interest (Subtopic 835-30)
In April 2015, the FASB issued ASU No. 2015-03, which simplifies the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update. The standard is effective for annual reporting periods beginning after December 15, 2015 and interim periods therein, and requires the use of the full retrospective approach. Early adoption is permitted for financial statements that have not been previously issued. As of December 31, 2015 **DP&L** had approximately $6.3 million in deferred financing costs classified in other current and other non-current assets that would be reclassified to reduce the related debt liabilities upon adoption of ASU No. 2015-03.

ASU No. 2015-15, Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements
In August 2015, the FASB issued ASU No. 2015-15, which clarifies that the SEC Staff would not object to an entity presenting debt issuance costs related to line-of-credit arrangements as an asset that is subsequently amortized ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. This standard should be adopted concurrent with adoption of ASU 2015-03 (which is described above). As of December 31, 2015, we had deferred financing costs related to lines of credit of approximately $0.7 million recorded within Other noncurrent assets that would not be reclassified upon adoption of this standard.

ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory
In July 2015, the FASB issued ASU No. 2015-11, which simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with a lower of cost or net realizable value test. The standard is effective for public entities for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted. The new guidance must be applied prospectively. As we already used the net realizable value to make lower of cost or market determinations, there will be no impact on our financial statements upon adoption of this standard.

ASU No. 2015-05, Intangibles – Goodwill and Other: Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement
In April 2015, the FASB issued ASU No. 2015-05, which clarifies how customers in cloud computing arrangements should determine whether the arrangement includes a software license and eliminates the existing requirement for customers to account for software licenses they acquired by analogizing to the accounting guidance on leases. The standard is effective for annual reporting periods beginning after December 15, 2015 and interim periods therein. Early adoption is permitted. The standard permits the use of a prospective or retrospective approach. As all of our cloud computing arrangements will continue to be accounted for as service agreements, there will be no impact on our financial statements upon the adoption of this standard.

ASU No. 2014-05, Presentation of Financial Statements: Going Concern
The FASB recently issued ASU 2014-15 "Presentation of Financial Statements - Going Concern (Subtopic 205-40: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern)" effective for annual and interim periods ending after December 15, 2016. ASU 2014-15 requires management to evaluate whether there are conditions or events, considered in aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. There are required disclosures if substantial doubt is identified including documentation of: principal conditions or events that raised substantial doubt about the entity's ability to continue as a going concern (before consideration of management's plans), management's evaluation of the significance of those conditions or events in relation to the entity's ability to meet its obligations, and management's plans that alleviated substantial doubt about the entity's ability to continue as a going concern. This ASU is not expected to have any impact on our overall results of operations, financial position or cash flows.

ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606)
In May 2014, the FASB issued ASU No. 2014-09, which clarifies principles for recognizing revenue and will result in a common revenue standard for U.S. GAAP and International Financial Reporting Standards. The objective of the new standard is to provide a single and comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The standard requires an entity to recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contract with Customers (Topic 606): Deferral of the Effective Date, which deferred the effective date of ASU 2014-09 by one year, resulting in the new revenue standard being effective for annual reporting periods beginning after December 15, 2017 and interim periods therein. Early adoption is now permitted only as of the original effective date for public entities (that is, no earlier than 2017 for calendar year-end entities). The standard permits the use of either a full retrospective or modified retrospective approach. We have not yet selected a transition method and are currently evaluating the impact of adopting the standard on our financial statements.

ASU No. 2015-02, Consolidation – Amendments to the Consolidation Analysis (Topic 810)
In February 2015, the FASB issued ASU 2015-02, which makes targeted amendments to the current consolidation guidance and ends the deferral granted to investment companies from applying the Variable Interest Entity (VIE) guidance. The standard amends the evaluation of whether (1) fees paid to a decision-maker or service providers represent a variable interest, (2) a limited partnership or similar entity has the characteristics of a VIE and (3) a reporting entity is the primary beneficiary of a VIE. The standard is effective for annual periods beginning after December 15, 2015 and interim periods therein. Early adoption is permitted. We do not expect this standard to have an impact on our financial statements upon adoption.

Note 2 – Supplemental Financial Information

$ in millions	December 31, 2015	December 31, 2014
Accounts receivable, net		
Unbilled revenue	**$ 43.3**	$ 49.0
Customer receivables	**54.1**	68.7
Amounts due from partners in jointly-owned stations	**16.0**	15.2
Other	**6.9**	20.7
Provisions for uncollectible accounts	**(0.8)**	(0.9)
Total accounts receivable, net	**$ 119.5**	$ 152.7
Inventories		
Fuel and limestone	**$ 72.2**	$ 65.3
Plant materials and supplies	**33.7**	32.3
Other	**2.1**	1.4
Total inventories, at average cost	**$ 108.0**	$ 99.0

Accumulated Other Comprehensive Income (Loss)
The amounts reclassified out of Accumulated Other Comprehensive Income / (Loss) by component during the years ended December 31, 2015, 2014 and 2013 are as follows:

Details about Accumulated Other Comprehensive Income / (Loss) Components	**Affected line item in the Statements of Operations**	**Years ended December 31,**		
$ in millions		**2015**	2014	2013
Gains and losses on Available-for-sale securities activity (Note 5):				
	Other income / (deductions)	**$ —**	$ 0.4	$ 2.1
	Tax expense	**—**	(0.2)	(0.7)
	Net of income taxes	**—**	0.2	1.4
Gains and losses on cash flow hedges (Note 6):				
	Interest expense	**(1.1)**	(1.1)	(2.1)
	Revenue	**(18.7)**	28.4	2.2
	Purchased power	**4.4**	(0.4)	5.0
	Total before income taxes	**(15.4)**	26.9	5.1
	Tax expense	**5.6**	(11.5)	(2.5)
	Net of income taxes	**(9.8)**	15.4	2.6
Amortization of defined benefit pension items (Note 9):				
	Reclassification to Other income / (deductions)	**5.6**	4.1	5.7
	Tax benefit	**(1.9)**	(1.4)	(1.9)
	Net of income taxes	**3.7**	2.7	3.8
Total reclassifications for the period, net of income taxes		**$ (6.1)**	$ 18.3	$ 7.8

The changes in the components of Accumulated Other Comprehensive Income / (Loss) during the years ended December 31, 2015 and 2014 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 at December 31, 2013	$ 0.8	$ 6.2	$ (33.7)	$ (26.7)
Other comprehensive loss before reclassifications	(0.3)	(18.8)	(14.8)	(33.9)
Amounts reclassified from accumulated other comprehensive income	0.2	15.4	2.7	18.3
Net current period other comprehensive loss	(0.1)	(3.4)	(12.1)	(15.6)
Balance at December 31, 2014	0.7	2.8	(45.8)	(42.3)
Other comprehensive income / (loss) before reclassifications	**(0.2)**	**18.2**	**1.7**	**19.7**
Amounts reclassified from accumulated other comprehensive income / (loss)	**—**	**(9.8)**	**3.7**	**(6.1)**
Net current period other comprehensive income / (loss)	**(0.2)**	**8.4**	**5.4**	**13.6**
Balance at December 31, 2015	**$ 0.5**	**$ 11.2**	**$ (40.4)**	**$ (28.7)**

Note 3 – Regulatory Assets and Liabilities

In accordance with FASC 980, we have recognized total regulatory assets of $194.3 million and $211.7 million at December 31, 2015 and 2014, respectively, and total regulatory liabilities of $151.4 million and $128.5 million at December 31, 2015 and 2014, respectively. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 1 – Overview and Summary of Significant Accounting Policies for accounting policies regarding Regulatory Assets and Liabilities.

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

$ in millions	Type of Recovery	Amortization Through	December 31, 2015		December 31, 2014	
Regulatory assets, current:						
Fuel and purchased power recovery costs	A	2016	**$**	**13.9**	$	16.3
Economic development costs	A	2016		**0.5**		2.1
Deferred storm costs	B	2015		**—**		22.3
Energy efficiency program	A	2016		**—**		1.8
Other miscellaneous	A	2016		**—**		1.7
Total regulatory assets, current			**$**	**14.4**	$	44.2
Regulatory assets, non-current:						
Pension benefits	B	Ongoing	**$**	**91.6**	$	99.6
Deferred recoverable income taxes	B/C	Ongoing		**36.4**		43.1
Fuel costs	B	Undetermined		**12.7**		—
Unrecovered OVEC charges	D	Undetermined		**10.5**		—
Unamortized loss on reacquired debt	B	Various		**9.0**		9.9
Smart grid and advanced metering infrastructure costs	D	Undetermined		**7.3**		6.6
Generation separation costs		Undetermined		**3.9**		1.6
Retail settlement system costs	D	Undetermined		**3.1**		3.1
Consumer education campaign	D	Undetermined		**3.0**		3.0
Rate case costs	D	Undetermined		**1.9**		—
Other miscellaneous	D	Undetermined		**0.5**		0.6
Total regulatory assets, non-current			**$**	**179.9**	$	167.5
Total regulatory assets			$	194.3	$	211.7
Regulatory liabilities, current:						
Energy efficiency program			**$**	**9.2**	$	—
Competitive bidding				**9.1**		—
Transmission costs				**3.7**		2.9
Reconciliation rider				**2.1**		—
Other miscellaneous				**0.3**		1.5
Total regulatory liabilities, current			**$**	**24.4**	$	4.4
Regulatory liabilities, non-current:						
Estimated costs of removal - regulated property			**$**	**121.8**	$	119.3
Postretirement benefits				**5.2**		4.8
Total regulatory liabilities, non-current			**$**	**127.0**	$	124.1
Total regulatory liabilities			**$**	**151.4**	$	128.5

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

Regulatory assets

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. The audit for 2014 is in process. The costs recovered through the fuel rider have decreased significantly over the past three years as more SSO supply is provided through the competitive bid. While no further fuel or purchased power costs will be recoverable through the rider, it will continue for up to six months to allow for recovery of the ending deferral amount.

Fuel costs - long-term represent unrecovered fuel costs related to **DP&L's** fuel rider from 2010 through 2015 resulting from a declining SSO customer base. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Economic development costs represent costs incurred to promote economic development within the State of Ohio. These costs are being recovered through an Economic Development Rider that is subject to a bi-annual true-up process for any over/under recovery of costs.

Deferred storm costs represent costs incurred to repair the damage to **DP&L's** distribution equipment by major storms in 2008, 2011 and 2012. All such costs have now been recovered.

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. In addition to recovery of program costs, this rider has allowed for **DP&L** to recover lost margin associated with decreases in sales as a result of the programs implemented. The authority to recover lost margin included a maximum amount, which **DP&L** reached in the fourth quarter of 2015. Consequently, we discontinued accruing an asset for lost revenues after the maximum was reached. In addition, this rider provides that **DP&L** can earn a "shared savings" incentive that is tiered depending upon the level of success the programs reach. In 2014 and 2015, the maximum shared savings was accrued based upon performance, which is equal to $4.5 million per year, after income taxes.

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 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.

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.

Unrecovered OVEC charges represent the portion of capacity charges from OVEC that were not recoverable through **DP&L's** fuel rider beginning in October 2014. **DP&L** expects to recover these costs through a future rate proceeding.

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

Smart Grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and the 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. This plan is currently under development and we plan to seek recover of these deferred costs in a regulatory rate proceeding in the near future. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

Generation separation costs represent financing, redemption and other costs related to the divestiture of **DP&L's** generation assets. The PUCO directed **DP&L** to divest its generation assets by January 1, 2017. **DP&L** requested and was granted permission by the PUCO to defer all financing, redemption and related costs it incurs to transfer its generation assets. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

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. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation. **DP&L** has requested recovery of these costs as part of its pending distribution rate case filing.

Rate case costs represent costs associated with preparing a distribution rate case. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Regulatory liabilities

Energy efficiency program costs see "*Regulatory Assets - Energy efficiency program costs*" above.

Competitive bidding represents costs associated with the development and implementation of a Competitive Bidding Process, establishing contracts to supply power for a portion of **DP&L's** Standard Service Offer load, as well as the net over/under recovery of the cost of the power purchased from the bid winners.

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.

Reconciliation rider represents the costs that exceed 10 percent of the base amount of the following riders: Fuel, RPM, Alternative Energy and Competitive Bidding. This rider is in an overcollection position and will be discontinued after this overcollection has been refunded to customers.

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 4 – Property, Plant and Equipment

The following is a summary of **DP&L's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2015 and 2014:

	December 31,			
$ in millions	**2015**	**Composite Rate**	2014	Composite Rate
Regulated:				
Transmission	**$ 413.7**	**2.3%**	$ 402.4	2.3%
Distribution	**1,639.7**	**3.3%**	1,568.0	3.5%
General	**96.9**	**8.4%**	116.1	6.7%
Non-depreciable	**62.5**	**N/A**	61.6	N/A
Total regulated	**2,212.8**		2,148.1	
Unregulated:				
Production / Generation	**3,016.8**	**2.1%**	2,957.7	2.4%
Non-depreciable	**15.1**	**N/A**	14.9	N/A
Total unregulated	**3,031.9**		2,972.6	
Total property, plant and equipment in service	**$ 5,244.7**	**2.6%**	$ 5,120.7	2.8%

DP&L and certain other Ohio utilities have undivided ownership interests in five 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. At December 31, 2015, **DP&L** had $39.0 million of construction work in process at such facilities. **DP&L's** share of the operations of such facilities is included within the corresponding line in the Statements 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.

Coal-fired facilities

DP&L's undivided ownership interest in such facilities at December 31, 2015, is as follows:

	DP&L Share		**DP&L** Carrying Value		
	Ownership %	Summer Production Capacity (MW)	Gross Plant In Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)
Jointly-owned production units					
Conesville - Unit 4	16.5	129	$ 27	$ 8	$ 1
Killen - Unit 2	67.0	402	655	326	2
Miami Fort - Units 7 and 8	36.0	368	366	171	6
Stuart - Units 1 through 4	35.0	808	772	338	18
Zimmer - Unit 1	28.1	371	1,104	690	12
Transmission (at varying percentages)			99	64	—
Total		2,078	$ 3,023	$ 1,597	$ 39

Each of the above generating units has SCR and FGD equipment installed.

Beckjord Unit 6 was retired effective October 1, 2014 and **DP&L** sold its interest in East Bend on December 30, 2014.

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 impairment expense of $86.0 million related to two of its stations, Conesville and East Bend. See Note 13 – Fixed-asset Impairment for more information on these impairments.

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 are associated with the retirement of our long-lived assets, consisting 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, 2013	$	19.9
Calendar 2014		
Additions		3.6
Accretion expense		1.1
Settlements		(1.7)
Balance at December 31, 2014		22.9
Calendar 2015		
Additions		40.3
Accretion expense		2.1
Settlements		(3.2)
Balance at December 31, 2015	$	62.1

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 $121.8 million and $119.3 million in estimated costs of removal at December 31, 2015 and 2014, respectively, as regulatory liabilities for our transmission and distribution property. These amounts represent the excess of the cumulative removal costs recorded through depreciation rates versus the cumulative removal costs actually incurred. See Note 3 – Regulatory Assets and Liabilities for additional information.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		
Balance at December 31, 2013	$	115.0
Calendar 2014		
Additions		19.6
Settlements		(15.3)
Balance at December 31, 2014		119.3
Calendar 2015		
Additions		24.3
Settlements		(21.8)
Balance at December 31, 2015	$	121.8

Note 5 – Fair Value

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, 2015 and 2014. See also Note 6 – Derivative Instruments and Hedging Activities for the fair values of our derivative instruments.

	December 31, 2015		December 31, 2014	
$ in millions	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Assets				
Money market funds	$ **0.2**	$ **0.2**	$ 0.1	$ 0.1
Equity securities	**3.0**	**3.8**	2.7	3.7
Debt securities	**4.4**	**4.3**	4.7	4.7
Hedge Funds	**0.4**	**0.4**	0.8	0.8
Real Estate	**0.3**	**0.3**	0.4	0.4
Total assets	$ **8.3**	$ **9.0**	$ 8.7	$ 9.7
Liabilities				
Debt	$ **762.9**	$ **764.2**	$ 877.1	$ 882.5

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); and
- 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, 2015 and 2014.

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 the carrying value, 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.

DP&L had $0.8 million ($0.5 million after tax) in unrealized gains and $0.1 million ($0.1 million after tax) in unrealized losses on the Master Trust assets in AOCI at December 31, 2015 and $1.1 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2014.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. During the past twelve months, an immaterial amount of unrealized gains were reversed into earnings. Over the next twelve months, an immaterial amount of unrealized gains is expected to be reversed to earnings.

The fair value of assets and liabilities at December 31, 2015 and the respective category within the fair value hierarchy for **DP&L** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2015 (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	3.8	—	3.8	—
Debt securities	4.3	—	4.3	—
Hedge Funds	0.4	—	0.4	—
Real Estate	0.3	—	0.3	—
Total Master trust assets	9.0	0.2	8.8	—
Derivative assets				
FTRs	0.2	—	—	0.2
Forward power contracts	30.6	—	30.6	—
Total derivative assets	30.8	—	30.6	0.2
Total assets	$ 39.8	$ 0.2	$ 39.4	$ 0.2
Liabilities				
FTRs	$ 0.5	$ —	$ —	$ 0.5
Forward power contracts	27.0	—	23.9	3.1
Total derivative liabilities	27.5	—	23.9	3.6
Long-term debt	764.2	—	746.1	18.1
Total liabilities	$ 791.7	$ —	$ 770.0	$ 21.7

(a) Includes credit valuation adjustment.

The fair value of assets and liabilities at December 31, 2014 and the respective category within the fair value hierarchy for **DP&L** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2014 (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	$ 0.1	$ 0.1	$ —	$ —
Equity securities	3.7	3.7	—	—
Debt securities	4.7	4.7	—	—
Hedge Funds	0.8	—	0.8	—
Real Estate	0.4	0.4	—	—
Total Master trust assets	9.7	8.9	0.8	—
Derivative assets				
Forward power contracts	15.1	—	13.9	1.2
Total derivative assets	15.1	—	13.9	1.2
Total assets	$ 24.8	$ 8.9	$ 14.7	$ 1.2
Liabilities				
Forward power contracts	$ 11.2	$ —	$ 11.2	$ —
FTRS	0.6	—	—	0.6
Heating Oil Futures	0.4	0.4	—	—
Natural Gas Futures	0.1	0.1	—	—
Total derivative liabilities	12.3	0.5	11.2	0.6
Long-term debt	882.5	—	864.3	18.2
Total liabilities	$ 894.8	$ 0.5	$ 875.5	$ 18.8

(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 (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.
- 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. The WPAFB note is not publicly traded. Fair value is assumed to equal carrying value. These fair value inputs are considered Level 3 in the fair value hierarchy as there are no observable inputs. Additional Level 3 disclosures were not presented since debt is not recorded at fair value.

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

Non-recurring Fair Value Measurements

We use the cost approach to determine the fair value of our AROs, which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. AROs for asbestos, ash ponds, underground storage tanks, and river structures increased by a net amount of $39.2 million ($25.5 million after tax) and $3.0 million ($2.0 million after tax) during the 12 months ended December 31, 2015 and 2014, respectively. The majority of the increase for 2015 is due to a net increase in the ARO for ash ponds of $40.3 million ($26.2 million after tax) as a result of new rules promulgated by the USEPA that were published in the Federal Register in April 2015 and became effective in October 2015. See Note 4 – Property, Plant and Equipment for more information about AROs.

When evaluating impairment of 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	Fair Value			Gross
	Amount	Level 1	Level 2	Level 3	Loss
Assets					
Long-lived assets held and used [(a)]					
Conesville	$ 30.0	$ —	$ —	$ 20.0	$ 10.0
East Bend	$ 76.0	$ —	$ —	$ —	$ 76.0

(a) See Note 13 – Fixed-asset Impairment 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)

Note 6 – 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 if they qualify under FASC 815 for accounting purposes.

At December 31, 2015, **DP&L** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	**Not designated**	**MWh**	**10.2**	**—**	**10.2**
Forward Power Contracts	**Designated**	**MWh**	**1,676.7**	**(7,795.8)**	**(6,119.1)**
Forward Power Contracts	**Not designated**	**MWh**	**5,049.9**	**(1,665.7)**	**3,384.2**

At December 31, 2014, **DP&L** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Not designated	MWh	10.5	—	10.5
Heating Oil Futures	Not designated	Gallons	378.0	—	378.0
Natural Gas	Not designated	Dths	200.0		200.0
Forward Power Contracts	Designated	MWh	175.0	(2,991.0)	(2,816.0)
Forward Power Contracts	Not designated	MWh	1,725.2	(2,804.0)	(1,078.8)

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 tables set forth the gains / (losses) recognized in AOCI and earnings related to the effective portion of derivative instruments and the gains / (losses) recognized in earnings related to the ineffective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the periods indicated:

	Years ended December 31,					
	2015	**2015**	2014	2014	2013	2013
$ in millions (net of tax)	**Power**	**Interest Rate Hedge**	Power	Interest Rate Hedge	Power	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	**$ 0.2**	**$ 2.6**	$ 1.0	$ 5.2	$ (4.7)	$ 7.3
Net gains / (losses) associated with current period hedging transactions	**18.2**	**—**	(18.8)	—	1.0	—
Net gains / (losses) reclassified to earnings:						
Interest Expense	**—**	**(0.6)**	—	(2.6)	—	(2.1)
Revenues	**(12.0)**	**—**	18.2	—	1.4	—
Purchased Power	**2.8**	**—**	(0.2)	—	3.3	—
Ending accumulated derivative gain in AOCI	**$ 9.2**	**$ 2.0**	$ 0.2	$ 2.6	$ 1.0	$ 5.2

Net gains or losses associated with the ineffective portion of the hedging transactions were immaterial in the periods presented.

Portion expected to be reclassified to earnings in the next twelve months [(a)]	**$ 5.9**	**$ (0.6)**
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**36**	**—**

(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.

Derivatives not designated as hedges

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 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, 2015, 2014 and 2013.

	Year ended December 31, 2015				
$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized loss	**$ 0.4**	**$ 0.3**	**$ (6.3)**	**$ 0.1**	**$ (5.5)**
Realized gain / (loss)	**(0.3)**	**(0.2)**	**(9.9)**	**(0.1)**	**(10.5)**
Total	**$ 0.1**	**$ 0.1**	**$ (16.2)**	**$ —**	**$ (16.0)**
Recorded on Balance Sheet:					
Regulatory asset	**$ 0.1**	**$ —**	**$ —**	**$ —**	**$ 0.1**
Recorded in Income Statement: gain / (loss)					
Revenue	**—**	**—**	**27.4**	**—**	**27.4**
Purchased Power	**—**	**0.1**	**(43.6)**	**—**	**(43.5)**
Fuel	**—**	**—**	**—**	**—**	**—**
Total	**$ 0.1**	**$ 0.1**	**$ (16.2)**	**$ —**	**$ (16.0)**

	Year ended December 31, 2014				
$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ (0.6)	$ (0.8)	$ (1.5)	$ (0.1)	$ (3.0)
Realized gain / (loss)	(0.1)	0.7	(3.0)	(0.1)	(2.5)
Total	$ (0.7)	$ (0.1)	$ (4.5)	$ (0.2)	$ (5.5)
Recorded on Balance Sheet:					
Regulatory asset	$ (0.1)	$ —	$ —	$ —	$ (0.1)
Recorded in Income Statement: gain / (loss)					
Revenue	$ —	$ —	$ 0.7	$ —	$ 0.7
Purchased Power	—	(0.1)	(5.2)	(0.2)	(5.5)
Fuel	(0.6)	—	—	—	(0.6)
Total	$ (0.7)	$ (0.1)	$ (4.5)	$ (0.2)	$ (5.5)

$ in millions	Year ended December 31, 2013 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 / (loss)	—	0.1	1.2	1.6	2.9
Total	$ —	$ 0.1	$ 1.5	$ 0.4	$ 2.0
Recorded on Balance Sheet:					
Partners' share of gain	$ —	$ —	$ —	$ —	$ —
Regulatory (asset) / liability	—	—	—	—	—
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

The following tables show the fair value, balance sheet classification and hedging designation of **DP&L's** derivative instruments at December 31, 2015 and 2014.

Fair Values of Derivative Instruments
December 31, 2015

$ 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	Designated	$ 16.2	$ (7.1)	$ —	$ 9.1
Forward power contracts	Not designated	7.4	(5.5)	—	1.9
FTRs		0.2	(0.2)	—	—
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Designated	3.0	(2.4)	—	0.6
Forward power contracts	Not designated	4.0	(2.7)	—	1.3
Total assets		$ 30.8	$ (17.9)	$ —	$ 12.9
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Designated	$ 7.1	$ (7.1)	$ —	$ —
Forward power contracts	Not designated	14.5	(5.5)	(8.0)	1.0
FTRs	Not designated	0.5	(0.2)	—	0.3
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Designated	2.7	(2.4)	—	0.3
Forward power contracts	Not designated	2.7	(2.7)	—	—
Total liabilities		$ 27.5	$ (17.9)	$ (8.0)	$ 1.6

Fair Values of Derivative Instruments
December 31, 2014

			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	Designated	$ 5.6	$ (2.0)	$ —	$ 3.6
Forward power contracts	Not designated	5.6	(3.4)	—	2.2
FTRs	Not designated	—	—	—	—
Heating oil futures	Not designated	—	—	—	—
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Designated	0.3	(0.3)	—	—
Forward power contracts	Not designated	3.6	(0.9)	—	2.7
Total assets		$ 15.1	$ (6.6)	$ —	$ 8.5
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Designated	$ 2.1	$ (2.0)	$ —	0.1
Forward power contracts	Not designated	7.5	(3.4)	(4.1)	—
FTRs	Not designated	0.6	—	—	0.6
Heating oil futures	Not designated	0.4	—	(0.4)	—
Natural gas futures	Not designated	0.1	—	(0.1)	—
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Designated	0.6	(0.3)	(0.3)	—
Forward power contracts	Not designated	1.0	(0.9)	—	0.1
Total liabilities		$ 12.3	$ (6.6)	$ (4.9)	$ 0.8

Credit risk-related contingent features
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. 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, 2015 is $27.5 million. This amount is offset by $8.0 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 $17.9 million. If **DP&L** debt were to fall below investment grade, **DP&L** could be required to post collateral for the remaining $1.6 million.

Note 7 – Debt

Long-term debt is as follows:

Long-term debt

$ in millions	Interest Rate	Maturity	December 31, 2015	December 31, 2014
First mortgage bonds	1.875%	2016	**$ 445.0**	$ 445.0
Pollution control series	4.7%	2028	**—**	35.3
Pollution control series	4.8%	2034	**—**	179.1
Pollution control series	4.8%	2036	**100.0**	100.0
Pollution control series - rates from: 0.02% - 0.12% and 0.04% - 0.15% (a)		2040	**—**	100.0
Pollution control series - rates from: 1.13% - 1.17%		2020	**200.0**	—
U.S. Government note	4.2%	2061	**18.1**	18.2
Unamortized debt discount			**(0.2)**	(0.5)
Subtotal			**762.9**	877.1
Less: current portion			**(444.9)**	(0.1)
Total			**$ 318.0**	$ 877.0

At December 31, 2015, maturities of long-term debt are summarized as follows:

Due within the twelve months ending December 31, $ in millions	
2016	$ 445.1
2017	0.1
2018	0.1
2019	0.2
2020	200.2
Thereafter	117.4
	763.1
Unamortized discount	(0.2)
Total long-term debt	$ 762.9

Significant transactions

On December 31, 2015, **DP&L** borrowed $35.0 million from **DPL** at an interest rate of 2.67%. The notes were due on or before December 31, 2016 and were repaid on January 29, 2016.

On July 1, 2015, the $35.3 million of **DP&L's** 4.7% pollution control bonds due January 2028 and $41.3 million of **DP&L's** 4.8% pollution control bonds due January of 2034 were called at par and were redeemed with cash.

On July 31, 2015, **DP&L** refinanced its revolving credit facility. The new facility has a $175.0 million borrowing limit, a $50.0 million letter of credit sublimit, a feature that provides **DP&L** the ability to increase the size of the facility by an additional $100.0 million and a maturity date of July 2020. At December 31, 2015, there were two letters of credit in the amount of $1.4 million outstanding, with the remaining $173.6 million available to **DP&L**. Fees associated with this revolving credit facility were not material during the years ended December 31, 2015 or 2014. Prior to refinancing the facility on July 31, 2015, this facility had a $300.0 million borrowing limit, a five-year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature that provided **DP&L** the ability to increase the size of the facility by an additional $100.0 million.

On August 3, 2015, **DP&L** called $100.0 million of variable rate pollution control bonds due November 2040, terminated the amended standby letter of credit facilities that supported these pollution control bonds, and called $137.8 million of 4.8% pollution control bonds due January of 2034. **DP&L** also used cash to redeem $37.8 million of these bonds and refinanced the $200.0 million balance, with new variable interest rate pollution control bonds secured by first mortgage bonds in an equivalent amount. In connection with the sale of the new pollution control bonds, **DP&L** entered into a certain Bond Purchase and Covenants Agreement, dated as of August 1, 2015, containing representations, warranties, covenants and defaults consistent with those contained in the revolving credit facilities loan documents of **DP&L**.

On March 31, 2014, **DP&L** borrowed $15.0 million from **DPL** at an interest rate of LIBOR plus 2.0%. This note was due on or before April 30, 2014 and was repaid on April 30, 2014.

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. Substantially concurrent with this transaction, **DP&L** redeemed $470.0 million of previously outstanding first mortgage bonds.

Debt covenants and restrictions

In connection with **DP&L's** sale of $200.0 million of variable rate pollution control bonds dated August 1, 2015, **DP&L** entered into an unsecured revolving credit agreement and a Bond Purchase and Covenants Agreement. These agreements contain representations, warranties, covenants and defaults consistent with those contained in the revolving credit facilities loan documents of **DP&L** and have two financial covenants. The first measures Total Debt to Total Capitalization and 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. The second financial covenant measures EBITDA to Interest Expense. 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.

As of December 31, 2015, **DP&L** was in compliance with all debt covenants, including the financial covenants described above and did not have any meaningful restrictions in its debt financing documents prohibiting dividends to its parent, **DPL**.

Note 8 – Income Taxes

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

$ in millions	Years ended December 31, 2015	2014	2013
Computation of tax expense			
Federal income tax expense [(a)]	$ **49.3**	$ 53.8	$ 35.5
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**0.4**	1.2	0.3
Depreciation of AFUDC - Equity	**(2.8)**	(2.7)	(2.5)
Investment tax credit amortized	**(2.4)**	(2.5)	(2.5)
Section 199 - domestic production deduction	**(6.1)**	(4.6)	(4.1)
Accrual (settlement) for open tax years	**—**	(6.6)	(8.8)
Other, net [(b)]	**(3.3)**	1.1	0.7
Total tax expense	$ **35.1**	$ 39.7	$ 18.6
Components of Tax Expense			
Federal - current	$ **55.8**	$ 34.1	$ 38.6
State and Local - current	**0.8**	0.5	(0.1)
Total current	**56.6**	34.6	38.5
Federal - deferred	**(21.0)**	4.1	(20.4)
State and local - deferred	**(0.5)**	1.0	0.5
Total deferred	**(21.5)**	5.1	(19.9)
Total tax expense	$ **35.1**	$ 39.7	$ 18.6

Effective and Statutory Rate Reconciliation

The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to **DP&L's** effective tax rate, as a percentage of income from continuing operations before taxes for the years ended December 31, 2015, 2014 and 2013:

	Years ended December 31, 2015	2014	2013
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
State taxes, net of Federal tax benefit	**0.3 %**	0.8 %	0.3 %
AFUDC - Equity	**(2.0)%**	(1.7)%	(2.4)%
Amortization of investment tax credits	**(1.7)%**	(1.6)%	(2.4)%
Section 199 - domestic production deduction	**(4.3)%**	(3.0)%	(4.0)%
Other - net	**(2.5)%**	(3.8)%	(8.3)%
Effective tax rate	**24.8 %**	25.7 %	18.2 %

Deferred Income Taxes

Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and (b) operating loss carryforwards. These items are stated at the enacted tax rates that are expected to be in effect when taxes are actually paid or recovered. Investment tax credits related to utility property have been deferred and are being amortized over the estimated useful lives of the related property.

Components of Deferred Tax Assets and Liabilities

$ in millions	December 31, 2015	2014
Net non-current Assets / (Liabilities)		
Depreciation / property basis	**$ (608.8)**	$ (618.8)
Income taxes recoverable	**(12.0)**	(14.8)
Regulatory assets	**(11.5)**	(18.0)
Investment tax credit	**7.0**	8.6
Compensation and employee benefits	**3.6**	5.2
Other	**(9.5)**	(12.2)
Net non-current liabilities	**$ (631.2)**	$ (650.0)
Net current Assets / (Liabilities) [(c)]		
Other	**$ —**	$ 0.5
Net current assets / (liabilities)	**$ —**	$ 0.5

(a) The statutory tax rate of 35% was applied to pre-tax earnings.
(b) Includes benefit of $0.4 million, expense of $0.7 million and benefit of $1.1 million in the years ended December 31, 2015, 2014 and 2013, respectively, of income tax related to adjustments from prior years.
(c) Amounts are included within Other prepayments and current assets and Other current liabilities 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	Years ended December 31, 2015	2014	2013
Tax expense / (benefit)	**$ 7.5**	$ (6.0)	$ 7.0

Uncertain Tax Positions
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, 2013	$ 8.8
Calendar 2014	
Tax positions taken during prior period	2.8
Lapse of Statute of Limitations	(8.6)
Settlement with taxing authorities	—
Balance at December 31, 2014	3.0
Calendar 2015	
Tax positions taken during prior period	—
Lapse of Statute of Limitations	—
Balance at December 31, 2015	$ 3.0

Of the December 31, 2015 balance of unrecognized tax benefits, $0.9 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 amounts accrued and expense (benefit) recorded were not material for each period presented.

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 statute 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 in 2013.

Note 9 – Benefit Plans

Defined contribution plans

DP&L sponsors two defined contribution plans. One is for non-union employees (the management plan) and one is for collective bargaining employees (the union plan). Both plans are qualified under Section 401 of the Internal Revenue Code.

Certain non-union employees become eligible to participate in the management plan on the first day of the month following the first full calendar month of employment; provided the employee worked at least 160 hours in that calendar month. Union employees become eligible to participate in the union plan on the first day of the first month following 30 days of employment. Effective January 1, 2016, employees in both plans are eligible to participate upon date of hire.

Participants may elect to contribute up to 85% of eligible compensation to their plan. Non-union participant contributions are matched 100% on the first 1% of eligible compensation and 50% on the next 5% of eligible compensation and they are fully vested in their employer contributions after 2 years of service. Union participant contributions are matched 150% but are capped at $2,100 for 2015 and they are fully vested in their employer contributions after 3 years of service. All participants are fully vested in their own contributions.

For the years ended December 31, 2015, 2014 and 2013 **DP&L's** contributions to all defined contribution plans were $4.8 million, $4.7 million and $4.8 million per year, respectively.

Defined benefit plans

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 January 1, 2014, the Service Company began providing services including accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including among other companies, **DPL** and **DP&L**. 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 has an immaterial unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. We also include our net liability to our partners related to our share of their pension costs within Pension, retiree and other benefits on our Balance Sheets.

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.

Postretirement benefits
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.

The following tables set forth the changes in our pension and postemployment benefit plans' obligations and assets recorded on the balance sheets at December 31, 2015 and 2014. The amounts presented in the following tables for pension obligations 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 obligations include both health and life insurance benefits.

$ in millions	Pension	
	Years ended December 31,	
	2015	2014
Change in benefit obligation		
Benefit obligation at beginning of period	**$ 443.8**	$ 370.5
Service cost	**7.1**	5.9
Interest cost	**17.3**	17.5
Plan amendments	**—**	6.8
Actuarial (gain) / loss	**(34.5)**	67.3
Benefits paid	**(22.9)**	(24.2)
Benefit obligation at end of period	**410.8**	443.8
Change in plan assets		
Fair value of plan assets at beginning of period	**371.7**	349.1
Actual return on plan assets	**(8.8)**	46.4
Contributions to plan assets	**5.4**	0.4
Benefits paid	**(22.9)**	(24.2)
Fair value of plan assets at end of period	**345.4**	371.7
Funded status of plan	**$ (65.4)**	$ (72.1)

	December 31,	
	2015	2014
Amounts recognized in the Balance sheets		
Current liabilities	**$ (0.4)**	$ (0.4)
Non-current liabilities	**(65.0)**	(71.7)
Net liability at Year ended December 31,	**$ (65.4)**	$ (72.1)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax		
Components:		
Prior service cost	**$ 17.0**	$ 20.3
Net actuarial loss / (gain)	**139.7**	152.5
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 156.7**	$ 172.8
Recorded as:		
Regulatory asset	**$ 91.1**	$ 99.0
Regulatory liability	**—**	—
Accumulated other comprehensive income	**65.6**	73.8
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 156.7**	$ 172.8

$ in millions	Postretirement	
	Years ended December 31,	
	2015	2014
Change in benefit obligation		
Benefit obligation at beginning of period	**$ 19.6**	$ 19.7
Service cost	**0.2**	0.2
Interest cost	**0.6**	0.8
Actuarial (gain) / loss	**(1.1)**	0.2
Benefits paid	**(1.5)**	(1.3)
Benefit obligation at end of period	**17.8**	19.6
Change in plan assets		
Fair value of plan assets at beginning of period	**3.3**	3.7
Contributions to plan assets	**1.0**	0.9
Benefits paid	**(1.5)**	(1.3)
Fair value of plan assets at end of period	**2.8**	3.3
Funded status of plan	**$ (15.0)**	$ (16.3)

	December 31,	
	2015	2014
Amounts recognized in the Balance sheets		
Current liabilities	**$ (0.4)**	$ (0.5)
Non-current liabilities	**(14.6)**	(15.8)
Net liability at Year ended December 31,	**$ (15.0)**	$ (16.3)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax		
Components:		
Prior service cost	**$ 0.5**	$ 0.6
Net actuarial loss / (gain)	**(6.2)**	(5.8)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ (5.7)**	$ (5.2)
Recorded as:		
Regulatory asset	**$ 0.3**	$ —
Regulatory liability	**(5.1)**	(4.5)
Accumulated other comprehensive income	**(0.9)**	(0.7)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ (5.7)**	$ (5.2)

The accumulated benefit obligation for our defined benefit pension plans was $401.2 million and $431.0 million at December 31, 2015 and 2014, respectively.

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

Net Periodic Benefit Cost - Pension

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Service cost	**$ 7.1**	$ 5.9	$ 7.2
Interest cost	**17.3**	17.5	15.6
Expected return on assets [(a)]	**(22.6)**	(22.9)	(23.6)
Amortization of unrecognized:			
Actuarial gain	**9.8**	6.4	9.3
Prior service cost	**3.3**	2.8	2.8
Net periodic benefit cost	**$ 14.9**	$ 9.7	$ 11.3

Net Periodic Benefit Cost - Postretirement

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Service cost	**$ 0.2**	$ 0.2	$ 0.2
Interest cost	**0.6**	0.8	0.8
Expected return on assets [(a)]	**(0.1)**	(0.2)	(0.2)
Amortization of unrecognized:			
Actuarial loss	**(0.6)**	(0.8)	(0.7)
Prior service cost	**0.1**	0.1	0.1
Net periodic benefit cost	**$ 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

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Net actuarial loss / (gain)	**$ (3.0)**	$ 43.8	$ (11.7)
Prior service cost	**—**	6.8	—
Reversal of amortization item:			
Net actuarial loss	**(9.8)**	(6.4)	(9.3)
Prior service cost	**(3.3)**	(2.8)	(2.8)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (16.1)**	$ 41.4	$ (23.8)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (1.2)**	$ 51.1	$ (12.5)

Postretirement

$ in millions	Years ended December 31, 2015	2014	2013
Net actuarial loss / (gain)	$ **(1.1)**	$ 0.4	$ (1.9)
Reversal of amortization item:			
Net actuarial gain	**0.6**	0.8	0.7
Prior service credit	**(0.1)**	(0.1)	(0.1)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **(0.6)**	$ 1.1	$ (1.3)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **(0.4)**	$ 1.2	$ (1.1)

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2016 are:

$ in millions	Pension	Postretirement
Actuarial gain / (loss)	$ 7.2	$ (0.8)
Prior service cost	$ 3.1	$ 0.1

Assumptions

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.

At December 31, 2015, we are maintaining our long term rate of return assumption of 6.50% for pension plan assets. In addition, we are decreasing our long-term rate of return assumption to 3.90% from 4.50% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our long-term portfolio mixes. Also, at December 31, 2015, we have increased our assumed discount rate to 4.49% from 4.02% for pension and to 4.10% from 3.71% for postemployment benefits expense to reflect current duration-based yield curve discount rates. A one percent increase in the rate of return assumption for pension would result in a decrease in pension expense of approximately $3.5 million. A 1% decrease in the rate of return assumption for pension would result in an increase in pension expense of approximately $3.5 million. A 25 basis point increase in the discount rate for pension would result in a decrease of approximately $0.2 million to 2016 pension expense. A 25 basis point decrease in the discount rate for pension would result in an increase of approximately $0.3 million to 2016 pension expense. A one percent change in the assumed health care cost trend rate would affect postemployment benefit costs by less than $1.0 million.

In determining the discount rate to use for valuing liabilities, we used a market yield curve on high-quality fixed income investments as of December 31, 2015. We project the expected benefit payments under the plan based on participant data and based on certain assumptions concerning mortality, retirement rates, termination rates, etc. The expected benefit payments for each year are then discounted back to the measurement date using the appropriate spot rate for each half-year from the yield curve, thereby obtaining a present value of all expected future benefit payments using the yield curve. Finally, an equivalent single discount rate is determined which produces a present value equal to the present value determined using the full yield curve.

Effective January 1, 2016 we will apply the spot rate approach for determining service cost and interest cost for its defined benefit pension plans and other post-retirement plan. The expected 2016 service costs and interest costs included above reflect the change in methodology. The impact of the change in approach is a reduction in: (1) expected service costs of $0.4 million for pension plans in 2016 ($0.4 million Defined Benefit Pension Plan and $0.0 million Supplemental Retirement Plan), and (2) expected interest costs of $3.2 million for pension plans in 2016 ($3.1 million Defined Benefit Pension Plan and $0.1 million Supplemental Retirement Plan).

The weighted average assumptions used to determine benefit obligations during the years ended December 31, 2015, 2014 and 2013 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2015	2014	2013	**2015**	2014	2013
Discount rate for obligations	**4.49%**	4.02%	4.86%	**4.10%**	3.71%	4.58%
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, 2015, 2014 and 2013 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2015	2014	2013	**2015**	2014	2013
Discount rate	**4.02%**	4.86%	4.04%	**3.81%**	4.51%	4.58%
Expected rate of return on plan assets	**6.50%**	6.75%	6.75%	**4.50%**	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, 2015, 2014 and 2013 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2015	2014	2013	**2015**	2014	2013
Pre - age 65						
Current health care cost trend rate	**6.97%**	7.75%	8.00%	**6.85%**	6.97%	7.75%
Year trend reaches ultimate	**2029**	2023	2019	**2036**	2029	2023
Post - age 65						
Current health care cost trend rate	**6.97%**	6.75%	7.50%	**6.85%**	6.97%	6.75%
Year trend reaches ultimate	**2029**	2021	2018	**2036**	2029	2021
Ultimate health care cost trend rate	**4.50%**	5.00%	5.00%	**4.50%**	4.50%	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	$ —
Benefit obligation	$ 1.1	$ (0.7)

Pension 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, as well as short-term tactical asset allocation guidelines, are determined by a Risk/Advisory Committee and approved by a Fiduciary Committee. These allocations take into account the Plan's long-term objectives. The long-term target allocations for plan assets are 18% – 38% for equity securities and 58% – 86% for fixed income securities. 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.

Tactically, the committees, on a short-term basis, will make asset allocations that are outside the long-term allocation guidelines. The short-term allocation positions are likely to not exceed one-year in duration. In addition to the equity and fixed income investments, the short-term allocation may also include a relatively small allocation to alternative investments. The plan currently has a small allocation to a core property fund, as well as a small allocation to a hedge fund.

Most of our Plan assets are measured using quoted, observable prices which are considered Level One inputs in the Fair Value Hierarchy. The Core property collective fund and the Common collective fund are measured using Level Two inputs that are quoted prices for identical assets in markets that are less active.

The following table summarizes our target pension plan allocation for 2015:

		Percentage of plan assets as of December 31,	
Asset Category	Long-Term Mid-Point Target Allocation	2015	2014
Equity Securities	28%	17%	18%
Debt Securities	72%	67%	69%
Real Estate	—%	9%	7%
Other	—%	7%	6%

The fair values of our pension plan assets at December 31, 2015 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2015

Asset Category $ in millions	Market Value at December 31, 2015	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	$ 9.2	$ 9.2	$ —	$ —
Large cap equity	20.2	20.2	—	—
International equity	18.2	18.2	—	—
Emerging markets equity	2.7	2.7	—	—
SIIT dynamic equity	10.0	10.0	—	—
Total equity securities	60.3	60.3	—	—
Debt Securities [b]				
Emerging markets debt	6.3	6.3	—	—
High yield bond	6.3	6.3	—	—
Long duration fund	219.5	219.5	—	—
Total debt securities	232.1	232.1	—	—
Other investments [c]				
Core property collective fund	30.2	—	30.2	—
Common collective fund	22.8	—	22.8	—
Total other investments	53.0	—	53.0	—
Total pension plan assets	$ 345.4	$ 292.4	$ 53.0	$ —

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(b) This category includes investments in investment-grade fixed-income instruments, 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 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 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, 2014 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2014

Asset Category $ in millions	Market Value at December 31, 2014	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	$ 10.6	$ 10.6	$ —	$ —
Large cap equity	22.2	22.2	—	—
International equity	18.2	18.2	—	—
Emerging markets equity	2.8	2.8	—	—
SIIT dynamic equity	11.6	11.6	—	—
Total equity securities	65.4	65.4	—	—
Debt Securities [(b)]				
Emerging markets debt	6.0	6.0	—	—
High yield bond	6.5	6.5	—	—
Long duration fund	242.7	242.7	—	—
Total debt securities	255.2	255.2	—	—
Cash and cash equivalents [(c)]				
Cash	1.6	1.6	—	—
Other investments [(d)]				
Core property collective fund	26.3	—	26.3	—
Common collective fund	23.2	—	23.2	—
Total other investments	49.5	—	49.5	—
Total pension plan assets	$ 371.7	$ 322.2	$ 49.5	$ —

(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, 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 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 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, 2015 by asset category are as follows:

Fair Value Measurements for Other Postemployment Benefit Plan Assets at December 31, 2015

Asset Category $ in millions	**Fair Value at December 31, 2015 (a)**	**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)]	$ 2.8	$ 2.8	$ —	$ —

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

The fair values of our other postemployment benefit plan assets at December 31, 2014 by asset category are as follows:

Fair Value Measurements for Other Postemployment Benefit Plan Assets at December 31, 2014

Asset Category $ in millions	Fair Value at December 31, 2014 (a)	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)]	$ 3.2	$ 3.2	$ —	$ —

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

Pension funding

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. We contributed $5.0 million, $0.0 million, and $0.0 million during the years ended December 31, 2015, 2014 and 2013, respectively.

We expect to make contributions of $0.4 million to our SERP in 2016 to cover benefit payments. We also expect to contribute $1.1 million to our other postemployment benefit plans in 2016 to cover benefit payments. We made contributions of $5.0 million to our pension plan during January, 2016.

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 2015 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 112.54% and is estimated to be 112.54% until the 2016 status is certified in September 2016 for the 2016 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.

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
2016	$ 24.6	$ 1.7
2017	$ 25.2	$ 1.6
2018	$ 25.8	$ 1.5
2019	$ 26.3	$ 1.4
2020	$ 26.7	$ 1.4
2021 - 2025	$ 134.8	$ 5.7

Note 10 – Equity

Redeemable Preferred Stock

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding at December 31, 2015. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding at December 31, 2015. The table below details the preferred shares outstanding at December 31, 2015 and 2014:

		December 31, 2015 and 2014		Par Value ($ in millions)	
	Preferred Stock Rate	Redemption price ($ per share)	Shares Outstanding	**December 31, 2015**	December 31, 2014
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, of which there were none at December 31, 2015. 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.

Dividend Restrictions

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, 2015, **DP&L's** retained earnings of 437.3 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.

Common Stock

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 2015. 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 11 – 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. At December 31, 2015, **DP&L** could be responsible for the repayment of 4.9%, or $74.5 million, of a $1,519.9 million debt obligation comprised of both fixed and variable rate securities with maturities between 2016 and 2040. This would only happen if this electric generation company defaulted on its debt payments. At December 31, 2015, 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, 2015, these include:

		Payments due in:			
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DP&L:					
Coal contracts [(a)]	374.2	186.9	187.3	—	—
Purchase orders and other contractual obligations	83.8	24.4	30.0	29.4	—

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

Coal contracts:
DP&L has entered into various long-term coal contracts to supply the coal requirements for the generating stations it operates. At December 31, 2015, 73% of our future committed coal obligations are with a single supplier. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Purchase orders and other contractual obligations:
At December 31, 2015, **DP&L** had various other contractual obligations, including non-cancelable contracts, to purchase goods and services with various terms and expiration dates.

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, 2015, 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 SIPs) 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 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.

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 $0.9 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 or a loss cannot be reasonably estimated. 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.

Note 12 – Related Party Transactions

In December 2013, an agreement was signed, effective January 1, 2014, whereby the Service Company began providing services including operations, accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including, among other companies, **DPL** and **DP&L**. The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable allocations. This includes ensuring that the regulated utilities served, including **DP&L**, are not subsidizing costs incurred for the benefit of other businesses.

The following table provides a summary of these transactions:

	Years ended December 31,		
$ in millions	**2015**	2014	2013
DP&L revenues:			
Sales to DPLER (including MC Squared) [(a)]	**$ 303.3**	$ 487.1	$ 453.9
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC [(b)]	**$ (3.2)**	$ (2.9)	$ (2.9)
Expense recoveries for services provided to DPLER [(c)]	**$ 2.4**	$ 2.2	$ 5.2
Transactions with the Service Company:			
Charges for services provided	**$ 30.9**	$ 30.5	$ —
Charges to the Service Company	**$ 6.1**	$ 2.3	$ —

Balances with related parties:	**At December 31, 2015**	At December 31, 2014
Net payable to the Service Company	**$ (0.5)**	$ (4.7)
Short-term loan with DPL Inc.	**$ 35.0**	$ —
Deposits received from DPLER [(d)]	**$ —**	$ 20.1

(a) **DP&L** sold 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. These agreements were terminated on the sale of DPLER on January 1, 2016.

(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.

Income taxes

AES files federal and state income tax returns which consolidate **DPL** and its subsidiaries, including **DP&L**. Under a tax sharing agreement with **DPL**, **DP&L** is responsible for the income taxes associated with its own taxable income and records the provision for income taxes using a separate return method. **DP&L** had a net receivable balance under this agreement of $1.5 million and $1.0 million as of December 31, 2015 and 2014, respectively, which is recorded in Other current assets on the accompanying Balance Sheets.

Note 13 – Fixed-asset Impairment

	Years ended December 31,		
	2015	2014	2013
East Bend	$ —	$ —	$ 76.0
Conesville	—	—	10.0
Total fixed-asset impairment expense	$ —	$ —	$ 86.0

East Bend and Conesville - During the fourth quarter of 2013, **DP&L** 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. **DP&L** 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, **DP&L** recognized an asset impairment expense of $10.0 million and $76.0 million for Conesville and East Bend, respectively.

Note 14 – Subsequent Event

On January 1, 2016, **DPL** closed on the sale of DPLER to IGS. Also on January 1, 2016, **DP&L** terminated the contract it had with DPLER for the supply of electricity. The agreement terminating the contract was signed on December 28, 2015 and **DP&L** received $27.7 million of restricted cash on December 31, 2015 for the early termination of the contract, which we expect to record as a gain in the first quarter of 2016. This amount is shown as Restricted cash with the associated liability shown as Advance on contract termination on the Balance Sheet as of December 31, 2015. As the cash we received was restricted upon receipt it is not shown on the Statement of Cash Flows.

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

None.

Item 9A – Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports that the Company files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosures.

We carried out the evaluation required by Rules 13a-15(b) and 15d-15(b), under the supervision and with the participation of our management, including the CEO and CFO, of the effectiveness of our "disclosure controls and procedures" (as defined in the Exchange Act Rules 13a-15(e) and 15d-15(e)). Based upon this evaluation, the CEO and CFO concluded that as of December 31, 2015, our disclosure controls and procedures were effective.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
- provide reasonable assurance that unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements are prevented or detected timely.

Management, including our CEO and CFO, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013. Based on this assessment, management believes that we maintained effective internal control over financial reporting as of December 31, 2015.

Changes in Internal Control Over Financial Reporting:

There were no changes that occurred during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 during the years ended December 31, 2015 and 2014. Other than as set forth below, no professional services were rendered or fees billed by Ernst & Young LLP during the years ended December 31, 2015 and 2014.

	Fees billed Years ended December 31, 2015	Fees billed Years ended December 31, 2014
Audit fees [a]	$ 1,649,045	$ 1,523,700
Audit-related Fees [b]	145,450	146,025
Tax Fees [c]	—	—
All Other Fees	—	—
Total	$ 1,794,495	$ 1,669,725

(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, Financial Statements 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
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)

DPL	DP&L	Exhibit Number	Exhibit	Location
X		4(i)	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(j)	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(k)	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(l)	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(m)	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		4(n)	Indenture, dated October 6, 2014, between DPL Inc. and U.S. Bank National Association.	Exhibit 4.1 to Report on Form 8-K filed October 10, 2014 (File No. 1-9052)
X		4(o)	Registration Rights Agreement, dated as of October 6, 2014, by and between DPL Inc. and 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 October 10, 2014 (File No. 1-9052)
X	X	4(p)	Loan Agreement, dated August 1, 2015, between the Ohio Air Quality Development Authority and The Dayton Power and Light Company, relating to the 2015 Series A pollution control bonds	Exhibit 4.1 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)
X	X	4(q)	Loan Agreement, dated August 1, 2015, between the Ohio Air Quality Development Authority and The Dayton Power and Light Company, relating to the 2015 Series B pollution control bonds	Exhibit 4.2 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)
X	X	4(r)	Forty-Eighth Supplemental Indenture dated as of August 1, 2015 between The Bank of New York Mellon, Trustee and The Dayton Power and Light Company	Exhibit 4.3 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)
X	X	4(s)	Forty-Ninth Supplemental Indenture dated as of August 1, 2015 between The Bank of New York Mellon, Trustee and The Dayton Power and Light Company	Exhibit 4.4 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)

DPL	DP&L	Exhibit Number	Exhibit	Location
X	X	4(t)	Bond Purchase and Covenants Agreement, dated as of August 3, 2015, among The Dayton Power and Light Company, SunTrust Bank, as Administrative Agent, and the several lenders from time to time party thereto	Exhibit 4.5 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)
X		10(a)	Credit Agreement, dated as of July 31, 2015, among DPL Inc., U.S. Bank National Association, as Administrative Agent, Collateral Agent, Swing Line Lender and an L/C Issuer, PNC Bank, National Association, as Syndication Agent and an L/C Issuer, Bank of America, N.A., as Documentation Agent and an L/C Issuer, and the other lenders party to the Credit Agreement	Exhibit 10.1 to Report on Form 8-K filed August 6, 2015 (File No. 1-9052)
X		10(b)	Guaranty Agreement, dated as of July 31, 2015, between DPL Energy, LLC and U.S. Bank National Association, as Administrative Agent	Exhibit 10.2 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)
X		10(c)	Pledge Agreement, dated as of July 31, 2015, between DPL Inc. and U.S. Bank National Association, as Collateral Agent	Exhibit 10.3 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)
X		10(d)	Open-end Mortgage, Security Agreement, Assignment of Leases and Rents, and Fixture Filing, dated as of July 31, 2015, made by DPL Energy LLC to U.S. Bank National Association, as Collateral Agent and Mortgagee	Exhibit 10.4 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)
X	X	10(e)	Credit Agreement, dated as of July 31, 2015, among The Dayton Power and Light Company, PNC Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, Fifth Third Bank, as Syndication Agent and an L/C Issuer, Bank of America, N.A., as Documentation Agent and an L/C Issuer, and the other lenders party to the Credit Agreement	Exhibit 10.5 to Report on Form 8-K filed August 6, 2015 (File No. 1-2385)
X		10(f)	Open-End Leasehold Mortgage, Security Agreement, Assignment of Leases and Rents, and Fixture Filing from DPL Energy, LLC to U.S. Bank National Association, dated as of October 29, 2015	Exhibit 10(a) to Report on Form 10-Q for the quarter ended September 30, 2015 (File No. 1-9052)
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)

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

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

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

SIGNATURES

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

	DPL Inc.
February 23, 2016	/s/ Kenneth J. Zagzebski
	Kenneth J. Zagzebski President and Chief Executive Officer (principal executive officer)
	The Dayton Power and Light Company
February 23, 2016	/s/ Thomas A. Raga
	Thomas A. Raga 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/ Brian A. Miller Brian A. Miller	Director and Chairman	February 23, 2016
/s/ Elizabeth Hackenson Elizabeth Hackenson	Director	February 23, 2016
/s/ Michael S. Mizell Michael S. Mizell	Director	February 23, 2016
/s/ Kazi K. Hasan Kazi K. Hasan	Director	February 23, 2016
/s/ Mary Stawikey Mary Stawikey	Director	February 23, 2016
/s/ Kenneth J. Zagzebski Kenneth J. Zagzebski	Director, President and Chief Executive Officer (principal executive officer)	February 23, 2016
/s/ Craig L. Jackson Craig L. Jackson	Chief Financial Officer (principal financial officer)	February 23, 2016
/s/ Kurt A. Tornquist Kurt A. Tornquist	Controller (principal accounting officer)	February 23, 2016

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/ Brian A. Miller Brian A. Miller	Director and Chairman	February 23, 2016
/s/ Kenneth J. Zagzebski Kenneth J. Zagzebski	Director	February 23, 2016
/s/ Elizabeth Hackenson Elizabeth Hackenson	Director	February 23, 2016
/s/ Michael S. Mizell Michael S. Mizell	Director	February 23, 2016
/s/ Kazi K. Hasan Kazi K. Hasan	Director	February 23, 2016
/s/ Paul L. Freedman Paul L. Freedman	Director	February 23, 2016
/s/ Tish D. Mendoza Tish D. Mendoza	Director	February 23, 2016
/s/ Thomas A. Raga Thomas A. Raga	Director, President and Chief Executive Officer (principal executive officer)	February 23, 2016
/s/ Craig L. Jackson Craig L. Jackson	Director, Vice President and Chief Financial Officer (principal financial officer)	February 23, 2016
/s/ Kurt A. Tornquist Kurt A. Tornquist	Controller (principal accounting officer)	February 23, 2016

Schedule II

DPL Inc.
VALUATION AND QUALIFYING ACCOUNTS
For each of the three years ended December 31, 2013 - 2015

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions [(a)]	Balance at End of Period
Year ended December 31, 2015				
Deducted from accounts receivable -				
Provision for uncollectible accounts [(b)]	$ 898	$ 3,766	$ 3,829	$ 835
Deducted from deferred tax assets -				
Valuation allowance for deferred tax assets	$ 18,900	$ 1,626	$ 3,280	$ 17,246
Year ended December 31, 2014				
Deducted from accounts receivable -				
Provision for uncollectible accounts [(b)]	$ 909	$ 4,011	$ 4,022	$ 898
Deducted from deferred tax assets -				
Valuation allowance for deferred tax assets	$ 13,721	$ 5,179	$ —	$ 18,900
Year ended December 31, 2013				
Deducted from accounts receivable -				
Provision for uncollectible accounts [(b)]	$ 923	$ 4,924	$ 4,938	$ 909
Deducted from deferred tax assets -				
Valuation allowance for deferred tax assets	$ 12,349	$ 2,159	$ 787	$ 13,721

(a) Amounts written off, net of recoveries of accounts previously written off

(b) Provision for uncollectible accounts related to Company's held-for-sale business as detailed below were excluded from the table above and were included in "Assets held for sale - current" in the consolidated balance sheets.

	For the years ended, December 31		
	2015	2014	2013
Beginning balance	369	251	161
Additions	2,035	3,633	1,232
Deductions	2,291	3,515	1,142
Ending balance	113	369	251

THE DAYTON POWER AND LIGHT COMPANY
VALUATION AND QUALIFYING ACCOUNTS
For each of the three years ended December 31, 2013 - 2015

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions [a]	Balance at End of Period
Year ended December 31, 2015				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 897	$ 3,766	$ 3,828	$ 835
Year ended December 31, 2014				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 909	$ 4,011	$ 4,023	$ 897
Year ended December 31, 2013				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 923	$ 4,924	$ 4,938	$ 909

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

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

FORM 10-K/A
Amendment No. 1

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

For the fiscal year ended **December 31, 2015**

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**

Securities registered pursuant to Section 12(g) 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 ☒

The Dayton Power and Light Company is a voluntary filer that has filed all applicable reports under Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months. During 2015, DPL Inc. was a voluntary filer until its May 29, 2015 Registration Statement on Form S-4 filed with the Securities and Exchange Commission was declared effective on June 12, 2015. DPL Inc. has 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/A or any amendment to this Form 10-K/A.

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.

At December 31, 2015, 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/A 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/A AND ARE THEREFORE FILING THIS FORM WITH THE REDUCED DISCLOSURE FORMAT.

Explanatory Note

We are filing this Amendment No. 1 ("Form 10-K/A") to our combined Annual Report on Form 10-K for the fiscal year ended December 31, 2015, as filed with the Securities and Exchange Commission (the "SEC") on February 24, 2016 (the "Form 10-K"), to correct the following inadvertent administrative error: the Reports of Independent Registered Public Accounting Firm previously filed with the Form 10-K have been amended to include the electronic signatures of Ernst & Young LLP on such reports for both DPL Inc. and The Dayton Power and Light Company, which signatures had been obtained prior to our filing the Form 10-K.

In accordance with Rule 12b-15 under the Securities Exchange Act of 1934, as amended, each item of the Form 10-K that is amended by this Form 10-K/A is restated in its entirety, and this Form 10-K/A is accompanied by restated and re-executed certifications on Exhibits 31(a) – (d) and Exhibits 32(a) – (d) by our Chief Executive Officer and Chief Financial Officer.

This Form 10-K/A speaks as of the original filing date of the Form 10-K and does not reflect any events that may have occurred subsequent to the original filing date. Except as described above, no other changes have been made to the Form 10-K and we are not amending any other part of, or updating any other disclosures made in, the Form 10K.

DPL Inc. and The Dayton Power and Light Company

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Amendment No. 1 to Annual Report on Form 10-K
Fiscal Year Ended December 31, 2015

GLOSSARY OF TERMS

The following select terms, abbreviations or acronyms are used in this Form 10-K/A:

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 AEP Generation, effective January 1, 2014.
AER	Alternative Energy Rider which allows DP&L to recover costs related to meeting the Ohio renewable portfolio standards.
AES	The AES Corporation, a global power company, the ultimate parent company of DPL
AES Ohio Generation	AES Ohio Generation, LLC (formerly DPLE), a wholly-owned subsidiary of DPL that owns and operates peaking generation facilities from which it makes wholesale sales
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CFTC	Commodity Futures Trading Commission
CAA	U.S. Clean Air Act
CAIR	Clean Air Interstate Rule
Capacity Market	The purpose of the capacity market is to enable PJM to obtain sufficient resources to reliably meet the needs of electric customers within the PJM footprint. PJM procures capacity, through a multi-auction structure, on behalf of the load serving entities to satisfy the load obligations. There are four 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.
CCEM	Customer Conservation and Energy Management
CO_2	Carbon Dioxide
ComEd	Commonwealth Edison
CP	In 2015, PJM adopted changes to the capacity market known as "Capacity Performance". The CP program offers the potential for higher capacity revenues, combined with substantially increased penalties for non-performance or under-performance during certain periods identified as "capacity performance hours." The DP&L units will operate under the CP construct starting June 1, 2016.
CRES	Competitive Retail Electric Service
CSAPR	Cross-State Air Pollution Rule
CWA	U.S. Clean Water Act
Dark spread	A common metric used to estimate returns over fuel costs of coal-fired electric generating units
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
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 (renamed AES Ohio Generation, LLC effective February 1, 2016)
DPLER	DPL Energy Resources, Inc., formerly a wholly-owned subsidiary of DPL which sold competitive electric energy and other energy services, including sales by a wholly-owned subsidiary, MC Squared, which DPLER sold on April 1, 2015. DPLER was sold by DPL on January 1, 2016. The DPLER sale agreement was signed on December 28, 2015.

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
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 and transmission lines in Ohio (Duke Energy Ohio, Inc.)
Dynegy	Dynegy, Inc., the parent of various subsidiaries that, along with AEP Generation and DP&L, co-owns electric generating units in Ohio
EBITDA	Earnings before interest, taxes, depreciation and amortization
EGU	Electric generating unit
ERISA	The Employee Retirement Income Security Act of 1974
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
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
kV	Kilovolts, 1,000 volts
kWh	Kilowatt hour
LIBOR	London Inter-Bank Offering Rate
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
MATS	Mercury and Air Toxics Standards
MC Squared	MC Squared Energy Services, LLC, a retail electricity supplier formerly wholly-owned by DPLER, sold on April 1, 2015
Merger	The merger of DPL and Dolphin Sub, Inc. (a wholly-owned subsidiary of AES) in accordance with the terms of an Agreement and Plan of Merger dated April 19, 2011 among DPL, AES and Dolphin Sub, Inc. a wholly-owned subsidiary of AES. On the Merger date, 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.
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
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
Non-bypassable	Charges that are assessed to all customers regardless of whom the customer selects as their retail electric generation supplier
NOV	Notice of Violation
NO_X	Nitrogen Oxide

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
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
OCI	Other Comprehensive Income
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
PPM	Parts per million
PRP	Potentially Responsible Party
Predecessor	DPL prior to the Merger date
PUCO	Public Utilities Commission of Ohio
ROE	Return on equity
RPM	The Reliability Pricing Model was PJM's capacity construct.
RTO	Regional Transmission Organization
SB 221	Ohio Senate Bill 221, is 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.
SB 310	Ohio Senate Bill 310, an Ohio electric energy bill that was passed in May 2014 that required all Ohio utilities to show on each bill the approximate cost of complying with renewable energy, energy efficiency and peak demand requirements. It froze the Ohio renewable and energy efficiency annual targets for two year and required a legislative committee to evaluate whether or not the targets should continue.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SEET	Significantly Excessive Earnings Test
Service Company	AES US Services, LLC, the shared services affiliate providing accounting, finance, and other support services to AES' U.S. SBU businesses
SFAS	Statement of Financial Accounting Standards
SIP	A State Implementation Plan is a plan for complying with the federal CAA, administered by the USEPA. The SIP consists of narrative, rules, technical documentation and agreements that an individual state will use to clean up polluted areas.
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
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

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
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
U.S. SBU	U. S. Strategic Business Unit, AES' reporting unit covering the businesses in the United States, including DPL

PART II

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.

We have audited the accompanying consolidated balance sheets of DPL Inc. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income/(loss), cash flows, and shareholder's equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule "Schedule II - Valuation and Qualifying Accounts" for each of the three years in the period ended December 31, 2015. 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 consolidated financial position of DPL Inc. at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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

February 23, 2016
Indianapolis, Indiana

DPL INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

$ in millions	Years ended December 31, 2015	2014	2013
Revenues	**$ 1,612.8**	$ 1,716.5	$ 1,579.0
Cost of revenues:			
Fuel	**259.8**	304.5	366.7
Purchased power	**562.6**	587.9	383.0
Total cost of revenues	**822.4**	892.4	749.7
Gross margin	**790.4**	824.1	829.3
Operating expenses:			
Operation and maintenance	**361.3**	362.4	365.7
Depreciation and amortization	**134.6**	135.6	129.2
General taxes	**87.0**	87.8	76.8
Goodwill impairment	**317.0**	—	306.3
Fixed-asset impairment	**—**	11.5	26.2
Other	**0.4**	(3.9)	2.5
Total operating expenses	**900.3**	593.4	906.7
Operating income / (loss)	**(109.9)**	230.7	(77.4)
Other income / (expense), net			
Investment income	**0.2**	0.9	1.4
Interest expense	**(118.3)**	(126.6)	(124.0)
Charge for early redemption of debt	**(2.1)**	(30.9)	(2.8)
Other deductions	**(1.3)**	(1.5)	(3.0)
Other expense, net	**(121.5)**	(158.1)	(128.4)
Earnings (loss) from continuing operations before income tax	**(231.4)**	72.6	(205.8)
Income tax expense from continuing operations	**20.0**	15.4	19.8
Net income / (loss) from continuing operations	**(251.4)**	57.2	(225.6)
Discontinued operations (Note 16)			
Income / (loss) from discontinued operations	**11.4**	(129.2)	6.0
Income tax expense / (benefit)	**(1.0)**	2.6	2.4
Discontinued operations	**12.4**	(131.8)	3.6
Net loss	**$ (239.0)**	**$ (74.6)**	**$ (222.0)**

See Notes to Consolidated Financial Statements.

DPL INC.
STATEMENTS OF COMPREHENSIVE LOSS

$ in millions	Years ended December 31, 2015	2014	2013
Net loss	**$ (239.0)**	$ (74.6)	$ (222.0)
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $0.1, $0.2 and $0.6 for each respective period	**(0.1)**	(0.3)	(1.2)
Reclassification to earnings, net of income tax benefit / (expense) of $0.0, ($0.2) and ($0.7) for each respective period	**—**	0.2	1.4
Total change in fair value of available-for-sale securities	**(0.1)**	(0.1)	0.2
Derivative activity:			
Change in derivative fair value, net of income tax benefit / (expense) of ($10.3), $10.3 and ($10.6) for each respective period	**18.2**	(19.0)	19.7
Reclassification to earnings, net of income tax benefit / (expense) of $5.4, ($9.5) and ($2.3) for each respective period	**(10.0)**	16.9	3.4
Total change in fair value of derivatives	**8.2**	(2.1)	23.1
Pension and postretirement activity:			
Prior service cost for the period, net of income tax benefit / (expense) of $0.0, $1.3 and $0.0 for each respective period	**—**	(2.2)	—
Net gain / (loss) for the period, net of income tax benefit / (expense) of ($1.2), $7.1 and ($2.7) for each respective period	**1.6**	(12.7)	4.9
Reclassification to earnings, net of income tax benefit / (expense) of ($0.2), $0.0 and $0.3 for each respective period	**0.2**	—	0.3
Total change in unfunded pension and postretirement	**1.8**	(14.9)	5.2
Other comprehensive income / (loss)	**9.9**	(17.1)	28.5
Net comprehensive loss	**$ (229.1)**	$ (91.7)	$ (193.5)

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32.4	$ 17.0
Restricted cash	92.7	16.8
Accounts receivable, net (Note 2)	120.9	136.5
Inventories (Note 2)	109.1	100.2
Taxes applicable to subsequent years	81.2	77.8
Regulatory assets, current (Note 3)	14.4	44.2
Other prepayments and current assets	46.6	38.9
Assets held for sale - current (Note 16)	62.2	67.3
Total current assets	559.5	498.7
Property, plant and equipment:		
Property, plant and equipment	2,909.0	2,754.1
Less: Accumulated depreciation and amortization	(432.3)	(317.9)
	2,476.7	2,436.2
Construction work in process	85.0	76.4
Total net property, plant and equipment	2,561.7	2,512.6
Other non-current assets:		
Regulatory assets, non-current (Note 3)	179.9	167.5
Goodwill (Note 7)	—	317.0
Intangible assets, net of amortization (Note 7)	5.0	7.8
Other deferred assets	34.7	39.7
Assets held for sale - non-current (Note 16)	—	34.5
Total other non-current assets	219.6	566.5
Total Assets	$ 3,340.8	$ 3,577.8
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 8)	$ 574.9	$ 20.1
Accounts payable	97.5	94.4
Accrued taxes	142.4	102.6
Accrued interest	21.4	27.2
Customer security deposits	15.2	14.4
Regulatory liabilities, current (Note 3)	24.4	4.4
Insurance and claims costs	5.9	6.4
Other current liabilities	54.5	46.3
Deposit received on sale of DPLER (Note 16)	75.5	—
Liabilities held for sale - current (Note 16)	1.6	17.1
Total current liabilities	1,013.3	332.9
Non-current liabilities:		
Long-term debt (Note 8)	1,434.5	2,139.6
Deferred taxes (Note 9)	568.7	587.3
Taxes payable	84.1	80.7
Regulatory liabilities, non-current (Note 3)	127.0	124.1
Pension, retiree and other benefits (Note 10)	87.1	95.9
Other deferred credits	88.3	50.5
Liabilities held for sale - non-current (Note 16)	—	0.2
Total non-current liabilities	2,389.7	3,078.3
Redeemable preferred stock of subsidiary (Note 11)	18.4	18.4
Commitments and contingencies (Note 12)		
Common shareholder's equity:		
Common stock:		
1,500 shares authorized; 1 share issued and outstanding at December 31, 2015 and 2014	—	—
Other paid-in capital	2,237.7	2,237.4
Accumulated other comprehensive income	17.4	7.5
Retained earnings / (deficit)	(2,335.7)	(2,096.7)
Total common shareholder's equity	(80.6)	148.2
Total Liabilities and Shareholder's Equity	$ 3,340.8	$ 3,577.8

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

$ in millions	Years ended December 31, 2015	2014	2013
Cash flows from operating activities:			
Net loss	$ (239.0)	$ (74.6)	$ (222.0)
Adjustments to reconcile Net loss to Net cash from operating activities			
Depreciation and amortization	138.8	139.8	132.9
Amortization of intangibles	—	1.2	7.1
Amortization of debt market value adjustments	(1.1)	0.3	(14.4)
Amortization of deferred financing costs	5.9	6.3	5.0
Unrealized loss on derivatives	5.8	3.0	5.9
Deferred income taxes	(17.1)	17.7	24.0
Charge for early redemption of debt	2.1	30.9	2.8
Goodwill impairment [(a)]	317.0	135.8	306.3
Fixed-asset impairment	—	11.5	26.2
Loss / (Gain) on asset disposal	0.4	(3.9)	2.5
Changes in certain assets and liabilities:			
Accounts receivable	43.4	0.5	7.4
Inventories	(9.0)	(24.9)	27.4
Prepaid taxes	(1.3)	(0.9)	0.7
Taxes applicable to subsequent years	(3.4)	(7.1)	(1.4)
Deferred regulatory costs, net	21.8	5.4	7.6
Accounts payable	(5.1)	32.1	(5.8)
Accrued taxes payable	43.8	20.7	(5.5)
Accrued interest payable	(5.7)	(1.3)	(3.3)
Other current and deferred liabilities	(10.4)	(40.6)	1.5
Pension, retiree and other benefits	(0.7)	19.1	1.8
Unamortized investment tax credit	(0.5)	(0.5)	(0.5)
Insurance and claims costs	(0.5)	(0.2)	(4.8)
Other	23.3	(26.2)	1.4
Net cash from operating activities	308.5	244.1	302.8
Cash flows from investing activities:			
Capital expenditures	(137.2)	(118.1)	(124.4)
Proceeds from sale of property	1.3	10.7	0.8
Insurance proceeds	—	0.3	7.6
Purchase of renewable energy credits	(0.8)	(3.5)	(3.9)
Decrease / (increase) in restricted cash	(0.4)	(3.3)	(2.8)
Other investing activities, net	0.4	1.3	(1.2)
Net cash from investing activities	(136.7)	(112.6)	(123.9)
Cash flows from financing activities:			
Deferred financing costs	(6.9)	(3.6)	(15.3)
Retirement of debt	(474.5)	(335.0)	(945.1)
Premium paid for early redemption of debt	—	(29.1)	(2.4)
Issuance of long-term debt	325.0	200.0	645.0
Borrowings from revolving credit facilities	80.0	190.0	50.0
Repayment of borrowings from revolving credit facilities	(80.0)	(190.0)	(50.0)
Net cash from financing activities	(156.4)	(167.7)	(317.8)
Cash and cash equivalents:			
Net increase / (decrease) in cash	15.4	(36.2)	(138.9)
Balance at beginning of period	17.0	53.2	192.1
Cash and cash equivalents at end of period	$ 32.4	$ 17.0	$ 53.2
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 111.6	$ 117.3	$ 137.5
Income taxes paid / (refunded), net	$ 0.8	$ 0.7	$ (5.2)
Non-cash financing and investing activities:			
Accruals for capital expenditures	$ 18.6	$ 16.3	$ 14.7

(a) Goodwill impairment of $135.8 million in 2014 has been reclassified to Discontinued operations in the Consolidated Statement of Operations.

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

$ in millions (except Outstanding Shares)	Common Stock [(a)] Outstanding Shares	Amount	Other Paid-in Capital	Accumulated Other Comprehensive Income / (Loss)	Retained Earnings/ (Deficit)	Total
Year ended December 31, 2013						
Beginning balance	1	$ —	$ 2,236.7	$ (3.9)	$ (1,806.0)	$ 426.8
Net comprehensive loss				28.5	(222.0)	(193.5)
Common stock dividends					—	—
Other [(b)]			0.3		5.9	6.2
Ending balance	1	—	2,237.0	24.6	(2,022.1)	239.5
Year ended December 31, 2014						
Net comprehensive loss				(17.1)	(74.6)	(91.7)
Other			0.4		—	0.4
Ending balance	1	—	2,237.4	7.5	(2,096.7)	148.2
Year ended December 31, 2015						
Net comprehensive loss				**9.9**	**(239.0)**	**(229.1)**
Other			**0.3**			**0.3**
Ending balance	**1**	**$ —**	**$ 2,237.7**	**$ 17.4**	**$ (2,335.7)**	**$ (80.6)**

(a) 1,500 shares authorized
(b) $5.9 million of dividends declared in 2012 were reversed in 2013.

See Notes to Consolidated Financial Statements.

DPL Inc.
Notes to Consolidated Financial Statements
For the years ended December 31, 2015, 2014 and 2013

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** one reportable segment is the Utility segment, comprised of its **DP&L** subsidiary. See Note 14 – Business Segments for more information relating to 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. 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 services are still regulated. **DP&L** has the exclusive right to provide such service to its approximately 517,000 customers located in West Central Ohio. Additionally, **DP&L** procures and provides 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 five coal-fired power stations. Beginning in 2014, **DP&L** no longer supplied 100% of the generation for SSO customers and starting January 2016, SSO is now 100% competitively bid. 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 sold electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

In accordance with the ESP Order, on December 30, 2013, **DP&L** filed an application with the PUCO stating its plan to transfer or sell its generation assets. On July 14, 2014, **DP&L** announced its decision to retain **DP&L's** generation assets. On September 17, 2014 the PUCO ordered that **DP&L's** application as amended and updated was approved. **DP&L** is required to sell or transfer its generation assets by January 1, 2017 and continues to look at multiple options to effectuate the separation, including transfer into an unregulated affiliate of **DPL** or through a sale.

DPLER was sold by **DPL** on January 1, 2016. DPLER sold competitive retail electric service, under contract, to residential, commercial and industrial customers. DPLER had approximately 125,000 customers located throughout Ohio. DPLER's operations included those of its wholly-owned subsidiary MC Squared through April 1, 2015, when DPLER sold MC Squared. Approximately 110,000 of DPLER's customers were also electric distribution customers of **DP&L**. DPLER did not own any transmission or generation assets, and it purchased all of its electric energy from **DP&L** to meet its sales obligations. DPLER's sales reflect the general economic conditions and seasonal weather patterns of the area. See Note 16 – Discontinued Operations for more information.

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. Effective February 1, 2016, DPLE was renamed AES Ohio Generation, LLC. **DPL** owns all of the common stock of its subsidiaries.

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 1,219 people at January 31, 2016, of which 1,189 were employed by **DP&L**. Approximately 60% of all **DPL** employees are under a collective bargaining agreement which expires on October 31, 2017.

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 4 – Property, Plant and Equipment for more information.

All material intercompany accounts and transactions are eliminated in consolidation.

Certain immaterial amounts from prior periods 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; assets and liabilities related to employee benefits; goodwill; and intangibles.

Valuation of Goodwill
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. See Note 7 – Goodwill and Other Intangible Assets for information regarding the impairments of goodwill in 2015, 2014 and 2013.

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 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. The power sales and purchases within **DP&L's** service territory are reported on a net hourly basis as revenues or purchased power on our Consolidated Statements 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. Amounts are written off when reasonable collections efforts have been exhausted.

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 $2.0 million, $1.5 million and $1.5 million in the years ended December 31, 2015, 2014 and 2013, 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. See Note 15 – Fixed-asset Impairment for more information.

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
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 that approximated 4.6% in 2015, 5.3% in 2014 and 5.8% in 2013. Depreciation expense was $125.9 million, $128.1 million and $120.9 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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. 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 **DP&L** 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 3 – Regulatory Assets and Liabilities for more information.

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 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. Emission allowances are amortized as they are used in our operations on a FIFO basis. Renewable energy credits are carried on a weighted average cost basis and amortized as they are used or retired. See Note 7 – Goodwill and Other Intangible Assets for additional information.

Income Taxes
Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. We establish an allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. Our tax positions are evaluated under a more likely than not recognition threshold and measurement analysis before they are recognized for financial statement reporting. Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid within one year. Our policy for interest and penalties is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statement of Operations.

Income taxes payable, which are includable in allowable costs for ratemaking purposes in future years, are recorded as regulatory assets with a corresponding deferred tax liability. Investment tax credits that reduced federal income taxes in the years they arose have been deferred and are being amortized to income over the useful lives of the properties in accordance with regulatory treatment. See Note 3 – Regulatory Assets and Liabilities for additional information.

DPL and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. 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 9 – Income Taxes 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 bases for public equity security and fixed maturity investments are 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 and certain other taxes are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Operations. The amounts for the years ended December 31, 2015, 2014 and 2013, were $49.9 million, $50.8 million and $50.5 million, respectively.

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 includes restrictions imposed by agreements related to deposits held as collateral. At December 31, 2015, restricted cash also includes cash received in connection with the sale of DPLER on January 1, 2016. See Note 16 – Discontinued Operations for additional information regarding the sale of DPLER.

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, which results in changes in fair value being recorded within accumulated other comprehensive income, a component of shareholder's equity. 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 6 – Derivative Instruments and Hedging Activities 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 solely to us, our subsidiaries and, in some cases, our partners in commonly-owned facilities we operate, for workers' compensation, general liability, and property damage on an ongoing basis. MVIC maintains an active run-off policy for directors' and officers' liability and fiduciary through their expiration in 2017, which may or may not be renewed at that time. Insurance and Claims Costs on **DPL's** Consolidated Balance Sheets associated with MVIC include estimated liabilities of approximately $5.9 million and $6.4 million at December 31, 2015 and 2014, respectively. In addition, **DP&L** is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. **DP&L** has estimated liabilities for medical, life, and disability reserves for claims costs below certain coverage thresholds of third-party providers of approximately $13.7 million and $15.6 million at December 31, 2015 and 2014, 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 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.

Pension and Postretirement Benefits

We recognize, in our Consolidated Balance Sheets, an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in the funded status recognized in AOCI, except for those portions of our pension and postretirement obligations that can be recovered through future rates. All plan assets are recorded at fair value. We follow the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

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.

Effective January 1, 2016, we will apply a disaggregated discount rate approach for determining service cost and interest cost for its defined benefit pension plans and post-retirement plans. This approach is consistent with the requirements of ASC 715 and is considered to be preferential to the aggregated single rate discount approach, which has historically been used in the U.S., because it is more consistent with the philosophy of a full yield curve valuation.

The change in discount rate approach did not have an impact on the measurement of the benefit obligations at December 31, 2015, nor will it impact future remeasurements. This change in approach will impact the service cost and interest cost recorded in 2016 and future years. It will also impact the actuarial gains and losses recorded in future years, as well as the amortization thereof.

The expected 2016 service costs and interest costs included in Note 10 – Benefit Plans reflect the change in methodology described above. The impact of the change in approach on expected service costs in 2016 is shown below:

$ in millions	Expected 2016 Service Cost			Expected 2016 Interest Cost		
	Disaggregated rate approach	Aggregate rate approach	Impact of change	Disaggregated rate approach	Aggregate rate approach	Impact of change
Total Pension	$ 5.7	$ 6.1	$ (0.4)	$ 14.8	$ 17.9	$ (3.1)
Total Postretirement Benefits	$ 0.2	$ 0.2	$ —	$ 0.6	$ 0.7	$ (0.1)
Total	$ 5.9	$ 6.3	$ (0.4)	$ 15.4	$ 18.6	$ (3.2)

See Note 10 – Benefit Plans for more information.

Related Party Transactions
In the normal course of business, **DPL** enters into transactions with related parties. All material intercompany accounts and transactions are eliminated in **DPL's** Consolidated Financial Statements.

See Note 13 – Related Party Transactions for more information on Related Party Transactions.

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 $0.3 million and $0.3 million at December 31, 2015 and 2014, respectively, is included in Other deferred assets within Other noncurrent assets. **DPL** also has a note payable to the Trust amounting to $15.6 million and $15.6 million at December 31, 2015 and December 31, 2014, respectively, that was established upon the Trust's deconsolidation in 2003. See Note 8 – Debt 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.

New accounting pronouncements adopted

ASU No. 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes
Effective December 31, 2015, we prospectively adopted ASU No. 2015-17, which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. As a result, each jurisdiction will now only have one net noncurrent deferred tax asset or liability. The guidance does not change the existing requirement that only permits offsetting within a jurisdiction; that is, companies will remain prohibited from offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. Additionally, the current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by the update. As we elected to apply this ASU prospectively, prior periods were not adjusted.

ASU No. 2015-13, Derivatives and Hedging (Topic 815):Derivatives and Hedging: Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Market
In August 2015, the FASB issued ASU No. 2015-13, which resolves the diversity in practice resulting from determining whether certain contracts qualify for the normal purchases and normal sales scope exception under ASC Topic 815, Derivatives and Hedging. This standard clarifies that entities would not be precluded from applying the normal purchases and normal sales exception to certain forward contracts that necessitate the transmission of electricity through, or delivery to a location within, a nodal energy market. The standard is effective upon issuance and should be applied prospectively. As we had designated qualifying contracts as normal purchase or normal sales, there was no impact on our financial statements upon adoption of this standard.

Accounting pronouncements issued but not yet effective

ASU No. 2016-01, Financial Instruments — Overall (Topic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities
In January 2016, the FASB issued ASU 2016-01, which was designed to improve the recognition and measurement of financial instruments through targeted changes to existing GAAP. The guidance requires equity investments (except those that are accounted for under the equity method of accounting or result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income; that entities use the exit price notion when measuring financial instrument fair values; that an entity separate presentation of financial assets and liabilities by measurement category and form of financial asset on the Balance Sheets or Notes to the financial statements; that an entity present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk (or "own credit") when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. Also, the standard eliminates the requirement for public entities to disclose the methods and significant assumptions used to estimate the fair value required to be disclosed for financial instruments measured at amortized cost on the Balance Sheets. The standard is effective beginning with interim periods starting after December 31, 2017 and cannot be applied early. We are currently evaluating the applicability and materiality of the standard, but we do not anticipate a material impact on our consolidated financial statements.

ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments
In September 2015, the FASB issued ASU 2015-16, which simplifies the measurement-period adjustments in business combinations. It eliminates the requirement that an acquirer in a business combination account for measurement-period adjustments retrospectively. An acquirer will recognize a measurement-period adjustment during the period in which it determines the amount of the adjustment. The standard is effective for public entities for annual reporting periods beginning after December 15, 2015, and interim periods therein. Early adoption is permitted for financial statements that have not been issued. The new guidance should be applied prospectively to adjustments to provisional amounts that occur after the effective date of this standard. We will adopt this standard on January 1, 2016, which is not expected to have a material impact on our consolidated financial statements.

ASU No. 2015-03, Interest – Imputation of Interest (Subtopic 835-30)
In April 2015, the FASB issued ASU No. 2015-03, which simplifies the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this update. The standard is effective for annual reporting periods beginning after December 15, 2015 and interim periods therein, and requires the use of the full retrospective approach. Early adoption is permitted for financial statements that have not been previously issued. As of December 31, 2015, **DPL** had approximately $16.1 million in deferred financing costs classified in other current and other non-current assets that would be reclassified to reduce the related debt liabilities upon adoption of ASU No. 2015-03.

ASU No. 2015-15, Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements
In August 2015, the FASB issued ASU No. 2015-15, which clarifies that the SEC Staff would not object to an entity presenting debt issuance costs related to line-of-credit arrangements as an asset that is subsequently amortized ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. This standard should be adopted concurrent with adoption of ASU 2015-03 (which is described above). As of December 31, 2015, we had deferred financing costs related to lines of credit of approximately $3.1 million recorded within Other noncurrent assets that would not be reclassified upon adoption of this standard.

ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory
In July 2015, the FASB issued ASU No. 2015-11, which simplifies the subsequent measurement of inventory. It replaces the current lower of cost or market test with a lower of cost or net realizable value test. The standard is effective for public entities for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted. The new guidance must be applied prospectively. As we already used the net realizable value to make lower of cost or market determinations, there will be no impact on our financial statements upon adoption of this standard.

ASU No. 2015-05, Intangibles – Goodwill and Other: Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement
In April 2015, the FASB issued ASU No. 2015-05, which clarifies how customers in cloud computing arrangements should determine whether the arrangement includes a software license and eliminates the existing requirement for customers to account for software licenses they acquired by analogizing to the accounting guidance on leases. The standard is effective for annual reporting periods beginning after December 15, 2015 and interim periods therein. Early adoption is permitted. The standard permits the use of a prospective or retrospective approach. As all of our cloud computing arrangements will continue to be accounted for as service agreements, there will be no impact on our financial statements upon the adoption of this standard.

ASU No. 2014-05, Presentation of Financial Statements: Going Concern
The FASB recently issued ASU 2014-15 "Presentation of Financial Statements - Going Concern (Subtopic 205-40: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern)" effective for annual and interim periods ending after December 15, 2016. ASU 2014-15 requires management to evaluate whether there are conditions or events, considered in aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. There are required disclosures if substantial doubt is identified including documentation of: principal conditions or events that raised substantial doubt about the entity's ability to continue as a going concern (before consideration of management's plans), management's evaluation of the significance of those conditions or events in relation to the entity's ability to meet its obligations, and management's plans that alleviated substantial doubt about the entity's ability to continue as a going concern. This ASU is not expected to have any impact on our overall results of operations, financial position or cash flows.

ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606)
In May 2014, the FASB issued ASU No. 2014-09, which clarifies principles for recognizing revenue and will result in a common revenue standard for U.S. GAAP and International Financial Reporting Standards. The objective of the new standard is to provide a single and comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The standard requires an entity to recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contract with Customers (Topic 606): Deferral of the Effective Date, which deferred the effective date of ASU 2014-09 by one year, resulting in the new revenue standard being effective for annual reporting periods beginning after December 15, 2017 and interim periods therein. Early adoption is now permitted only as of the original effective date for public entities (that is, no earlier than 2017 for calendar year-end entities). The standard permits the use of either a full retrospective or modified retrospective approach. We have not yet selected a transition method and are currently evaluating the impact of adopting the standard on our financial statements.

ASU No. 2015-02, Consolidation – Amendments to the Consolidation Analysis (Topic 810)
In February 2015, the FASB issued ASU 2015-02, which makes targeted amendments to the current consolidation guidance and ends the deferral granted to investment companies from applying the Variable Interest Entity (VIE) guidance. The standard amends the evaluation of whether (1) fees paid to a decision-maker or service providers represent a variable interest, (2) a limited partnership or similar entity has the characteristics of a VIE and (3) a reporting entity is the primary beneficiary of a VIE. The standard is effective for annual periods beginning after December 15, 2015 and interim periods therein. Early adoption is permitted. We do not expect this standard to have an impact on our financial statements upon adoption.

Note 2 – Supplemental Financial Information

$ in millions	December 31, 2015	December 31, 2014
Accounts receivable, net		
Unbilled revenue	**$ 43.3**	$ 49.1
Customer receivables	**56.4**	70.1
Amounts due from partners in jointly-owned stations	**16.0**	15.2
Other	**6.0**	3.0
Provisions for uncollectible accounts	**(0.8)**	(0.9)
Total accounts receivable, net	**$ 120.9**	$ 136.5
Inventories		
Fuel and limestone	**$ 72.2**	$ 65.3
Plant materials and supplies	**34.9**	33.5
Other	**2.0**	1.4
Total inventories, at average cost	**$ 109.1**	$ 100.2

Accounts receivable of $31.0 million and $64.4 million as of December 31, 2015 and 2014 have been excluded from the above table as they have been reclassified as "Assets held for sale". See Note 16 – Discontinued Operations.

Accumulated Other Comprehensive Income / (Loss)

The amounts reclassified out of Accumulated Other Comprehensive Income / (Loss) by component during the years ended December 31, 2015, 2014 and 2013 are as follows:

Details about Accumulated Other Comprehensive Income / (Loss) Components	**Affected line item in the Consolidated Statements of Operations**	**Years ended December 31,**		
$ in millions		**2015**	2014	2013
Gains and losses on Available-for-sale securities activity (Note 5):				
	Other income / (deductions)	**$ —**	$ 0.4	$ 2.1
	Tax expense	**—**	(0.2)	(0.7)
	Net of income taxes	**—**	0.2	1.4
Gains and losses on cash flow hedges (Note 6):				
	Interest Expense	**(1.1)**	(1.3)	—
	Revenue	**(18.7)**	28.4	2.2
	Purchased power	**4.4**	(0.7)	3.5
	Total before income taxes	**(15.4)**	26.4	5.7
	Tax benefit / (expense)	**5.4**	(9.5)	(2.3)
	Net of income taxes	**(10.0)**	16.9	3.4
Amortization of defined benefit pension items (Note 10):				
	Operations and maintenance	**0.4**	—	—
	Tax expense	**(0.2)**	—	0.3
	Net of income taxes	**0.2**	—	0.3
Total reclassifications for the period, net of income taxes		**$ (9.8)**	$ 17.1	$ 5.1

The changes in the components of Accumulated Other Comprehensive Income / (Loss) during the years ended December 31, 2015 and 2014 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 at December 31, 2013	$ 0.6	$ 20.6	$ 3.4	$ 24.6
Other comprehensive loss before reclassifications	(0.3)	(19.0)	(14.9)	(34.2)
Amounts reclassified from accumulated other comprehensive income / (loss)	0.2	16.9	—	17.1
Net current period other comprehensive loss	(0.1)	(2.1)	(14.9)	(17.1)
Balance at December 31, 2014	0.5	18.5	(11.5)	7.5
Other comprehensive income / (loss) before reclassifications	**(0.1)**	**18.2**	**1.6**	**19.7**
Amounts reclassified from accumulated other comprehensive income / (loss)	**—**	**(10.0)**	**0.2**	**(9.8)**
Net current period other comprehensive income / (loss)	**(0.1)**	**8.2**	**1.8**	**9.9**
Balance at December 31, 2015	**$ 0.4**	**$ 26.7**	**$ (9.7)**	**$ 17.4**

Note 3 – Regulatory Assets and Liabilities

In accordance with FASC 980, we have recognized total regulatory assets of $194.3 million and $211.7 million at December 31, 2015 and 2014, respectively, and total regulatory liabilities of $151.4 million and $128.5 million at December 31, 2015 and 2014, respectively. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 1 – Overview and Summary of Significant Accounting Policies for accounting policies regarding Regulatory Assets and Liabilities.

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

$ in millions	Type of Recovery	Amortization Through	December 31, 2015	2014
Regulatory assets, current:				
Fuel and purchased power recovery costs	A	2016	**$ 13.9**	$ 16.3
Economic development costs	A	2016	**0.5**	2.1
Deferred storm costs	B	2015	**—**	22.3
Energy efficiency program	A	2016	**—**	1.8
Other miscellaneous	A	2016	**—**	1.7
Total regulatory assets, current			**14.4**	44.2
Regulatory assets, non-current:				
Pension benefits	B	Ongoing	**$ 91.6**	$ 99.6
Deferred recoverable income taxes	B/C	Ongoing	**36.4**	43.1
Fuel costs	B	Undetermined	**12.7**	—
Unrecovered OVEC charges	D	Undetermined	**10.5**	—
Unamortized loss on reacquired debt	B	Various	**9.0**	9.9
Smart grid and advanced metering infrastructure costs	D	Undetermined	**7.3**	6.6
Generation separation costs	D	Undetermined	**3.9**	1.6
Retail settlement system costs	D	Undetermined	**3.1**	3.1
Consumer education campaign	D	Undetermined	**3.0**	3.0
Rate case costs	D	Undetermined	**1.9**	—
Other miscellaneous	D	Undetermined	**0.5**	0.6
Total regulatory assets, non-current			**179.9**	167.5
Total regulatory assets			$ 194.3	$ 211.7
Regulatory liabilities, current:				
Energy efficiency program			**$ 9.2**	$ —
Competitive bidding			**9.1**	—
Transmission costs			**3.7**	2.9
Reconciliation rider			**2.1**	—
Other miscellaneous			**0.3**	1.5
Total regulatory liabilities, current			**24.4**	4.4
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated property			**$ 121.8**	$ 119.3
Postretirement benefits			**5.2**	4.8
Total regulatory liabilities, non-current			**127.0**	124.1
Total regulatory liabilities			**$ 151.4**	$ 128.5

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

Regulatory assets

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. The audit for 2014 is in process. The costs recovered through the fuel rider have decreased significantly over the past three years as more SSO supply is provided through the competitive bid. While no further fuel or purchased power costs will be recoverable through the rider, it will continue for up to six months to allow for recovery of the ending deferral amount.

Fuel costs - long-term represent unrecovered fuel costs related to **DP&L's** fuel rider from 2010 through 2015 resulting from a declining SSO customer base. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Economic development costs represent costs incurred to promote economic development within the State of Ohio. These costs are being recovered through an Economic Development Rider that is subject to a bi-annual true-up process for any over/under recovery of costs.

Deferred storm costs represent costs incurred to repair the damage to **DP&L's** distribution equipment by major storms in 2008, 2011 and 2012. All such costs have now been recovered.

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. In addition to recovery of program costs, this rider has allowed for **DP&L** to recover lost margin associated with decreases in sales as a result of the programs implemented. The authority to recover lost margin included a maximum amount, which **DP&L** reached in the fourth quarter of 2015. Consequently, we discontinued accruing an asset for lost revenues after the maximum was reached. In addition, this rider provides that **DP&L** can earn a "shared savings" incentive that is tiered depending upon the level of success the programs reach. In 2014 and 2015, the maximum shared savings was accrued based upon performance, which is equal to $4.5 million per year, after income taxes.

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 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.

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.

Unrecovered OVEC charges represent the portion of capacity charges from OVEC that were not recoverable through **DP&L's** fuel rider beginning in October 2014. **DP&L** expects to recover these costs through a future rate proceeding.

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

Smart Grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and the 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. This plan is currently under development and we plan to seek recover of these deferred costs in a regulatory rate proceeding in the near future. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

Generation separation costs represent financing, redemption and other costs related to the divestiture of **DP&L's** generation assets. The PUCO directed **DP&L** to divest its generation assets by January 1, 2017. **DP&L** requested and was granted permission by the PUCO to defer all financing, redemption and related costs it incurs to transfer its generation assets. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

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. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation. **DP&L** has requested recovery of these costs as part of its pending distribution rate case filing.

Rate case costs represent costs associated with preparing a distribution rate case. **DP&L** has requested recovery of these costs as part of its pending Distribution Rate Case filing.

Regulatory liabilities

Energy efficiency program costs see "*Regulatory Assets - Energy efficiency program costs*" above.

Competitive bidding represents costs associated with the development and implementation of a Competitive Bidding Process, establishing contracts to supply power for a portion of **DP&L's** Standard Service Offer load, as well as the net over/under recovery of the cost of the power purchased from the bid winners.

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.

Reconciliation rider represents the costs that exceed 10 percent of the base amount of the following riders: Fuel, RPM, Alternative Energy and Competitive Bidding. This rider is in an overcollection position and will be discontinued after this overcollection has been refunded to customers.

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 4 – Property, Plant and Equipment

The following is a summary of **DPL's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2015 and 2014:

	December 31,			
$ in millions	**2015**	**Composite Rate**	2014	Composite Rate
Regulated:				
Transmission	**$ 239.4**	**3.9%**	$ 227.5	4.1%
Distribution	**1,085.7**	**5.0%**	1,011.7	5.4%
General	**65.9**	**12.4%**	62.5	12.4%
Non-depreciable	**62.5**	**N/A**	61.6	N/A
Total regulated	**1,453.5**		1,363.3	
Unregulated:				
Production / Generation	**1,418.7**	**4.2%**	1,354.9	5.4%
Other	**17.0**	**8.1%**	16.1	5.5%
Non-depreciable	**19.8**	**N/A**	19.8	N/A
Total unregulated	**1,455.5**		1,390.8	
Total property, plant and equipment in service	**$ 2,909.0**	**4.6%**	$ 2,754.1	5.3%

DP&L and certain other Ohio utilities have undivided ownership interests in five 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. At December 31, 2015, **DP&L** had $39.0 million of construction work in process at such facilities. **DP&L's** share of the operations of such facilities is included within the corresponding line in the Statements 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.

Coal-fired facilities

DP&L's undivided ownership interest in such facilities at December 31, 2015, is as follows:

	DP&L Share		**DPL** Carrying Value		
	Ownership (%)	Summer Production Capacity (MW)	Gross Plant In Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)
Jointly-owned production units					
Conesville - Unit 4	16.5	129	$ 26	$ 4	$ 1
Killen - Unit 2	67.0	402	342	29	2
Miami Fort - Units 7 and 8	36.0	368	219	32	6
Stuart - Units 1 through 4	35.0	808	236	19	18
Zimmer - Unit 1	28.1	371	188	44	12
Transmission (at varying percentages)			43	8	—
Total		2,078	$ 1,054	$ 136	$ 39

Each of the above generating units has SCR and FGD equipment installed.

Beckjord Unit 6 was retired effective October 1, 2014, and **DP&L's** sale of its interest in East Bend closed on December 30, 2014.

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 are associated with the retirement of our long-lived assets, consisting 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, 2013	$	24.4
Calendar 2014		
Additions		3.6
Accretion expense		0.9
Settlements		(2.0)
Balance at December 31, 2014		26.9
Calendar 2015		
Additions		40.3
Accretion expense		1.9
Settlements		(3.2)
Balance at December 31, 2015	$	65.9

Asset Removal Costs
We continue to record costs of removal for our regulated transmission and distribution assets through our depreciation rates and recover those amounts in rates charged to our customers. There are no known legal AROs associated with these assets. We have recorded $121.8 million and $119.3 million in estimated costs of removal at December 31, 2015 and 2014, respectively, as regulatory liabilities for our transmission and distribution property. These amounts represent the excess of the cumulative removal costs recorded through depreciation rates versus the cumulative removal costs actually incurred. See Note 3 – Regulatory Assets and Liabilities for additional information.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		
Balance at December 31, 2013	$	115.0
Calendar 2014		
Additions		19.6
Settlements		(15.3)
Balance at December 31, 2014		119.3
Calendar 2015		
Additions		24.3
Settlements		(21.8)
Balance at December 31, 2015	$	121.8

Note 5 – Fair Value

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, 2015 and 2014. See Note 6 – Derivative Instruments and Hedging Activities for the fair values of our derivative instruments.

	December 31, 2015		December 31, 2014	
$ in millions	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Assets				
Money market funds	**$ 0.2**	**$ 0.2**	$ 0.1	$ 0.1
Equity securities	**3.0**	**3.8**	2.7	3.7
Debt securities	**4.4**	**4.3**	4.7	4.7
Hedge Funds	**0.4**	**0.4**	0.8	0.8
Real Estate	**0.3**	**0.3**	0.4	0.4
Total assets	**$ 8.3**	**$ 9.0**	$ 8.7	$ 9.7
Liabilities				
Debt	**$ 2,009.4**	**$ 1,975.3**	$ 2,159.7	$ 2,204.8

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); and
- 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, 2015 and 2014.

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 the carrying value, 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 $0.7 million ($0.5 million after tax) in unrealized gains and $0.1 million ($0.1 million after tax) in unrealized losses on the Master Trust assets in AOCI at December 31, 2015, and $0.8 million ($0.5 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2014.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. During the past twelve months, an immaterial amount of unrealized gains were reversed into earnings. Over the next twelve months, an immaterial amount of unrealized gains is expected to be reversed to earnings.

The fair value of assets and liabilities at December 31, 2015 and the respective category within the fair value hierarchy for **DPL** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2015 (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	3.8	—	3.8	—
Debt securities	4.3	—	4.3	—
Hedge Funds	0.4	—	0.4	—
Real Estate	0.3	—	0.3	—
Total Master trust assets	9.0	0.2	8.8	—
Derivative assets				
Forward power contracts	30.5	—	30.5	—
FTRs	0.2	—	—	0.2
Total Derivative assets	$ 30.7	$ —	$ 30.5	$ 0.2
Total assets	$ 39.7	$ 0.2	$ 39.3	$ 0.2
Liabilities				
FTRs	0.5	$ —	$ —	$ 0.5
Forward power contracts	27.0	—	23.9	3.1
Total derivative liabilities	27.5	—	23.9	3.6
Long-term debt	1,975.3	—	1,957.2	18.1
Total liabilities	$ 2,002.8	$ —	$ 1,981.1	$ 21.7

(a) Includes credit valuation adjustment.

The fair value of assets and liabilities at December 31, 2014 and the respective category within the fair value hierarchy for **DPL** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2014 (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	$ 0.1	$ 0.1	$ —	$ —
Equity securities	3.7	3.7	—	—
Debt securities	4.7	4.7	—	—
Hedge Funds	0.8	—	0.8	—
Real Estate	0.4	0.4	—	—
Total Master trust assets	9.7	8.9	0.8	—
Derivative assets				
Forward power contracts	14.9	—	13.7	1.2
Total derivative assets	14.9	—	13.7	1.2
Total assets	$ 24.6	$ 8.9	$ 14.5	$ 1.2
Liabilities				
FTRs	$ 0.6	$ —	$ —	$ 0.6
Heating oil futures	0.4	0.4	—	—
Natural gas futures	0.1	0.1	—	—
Forward power contracts	11.1	—	11.1	—
Total derivative liabilities	12.2	0.5	11.1	0.6
Long-term debt	2,204.8	—	2,186.6	18.2
Total liabilities	$ 2,217.0	$ 0.5	$ 2,197.7	$ 18.8

(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 (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.
- 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. The WPAFB note is not publicly traded. Fair value is assumed to equal carrying value. These fair value inputs are considered

Level 3 in the fair value hierarchy as there are no observable inputs. Additional Level 3 disclosures were not presented since debt is not recorded at fair value.

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

Non-recurring Fair Value Measurements
We use the cost approach to determine the fair value of our AROs, which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. AROs for asbestos, ash ponds, underground storage tanks, and river structures increased by a net amount of $39.0 million ($25.4 million after tax) and $2.5 million ($1.6 million after tax) during the 12 months ended December 31, 2015 and 2014, respectively. The majority of the increase for 2015 is due to a net increase in the ARO for ash ponds of $40.3 million ($26.2 million after tax) as a result of new rules promulgated by the USEPA that were published in the Federal Register in April 2015 and became effective in October 2015. See Note 4 – Property, Plant and Equipment for more information about AROs.

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, 2015**				
	Carrying Amount	**Fair Value Level 1**	**Fair Value Level 2**	**Fair Value Level 3**	**Gross Loss**
Goodwill [(b)]					
DP&L reporting unit	$ **317.0**	$ **—**	$ **—**	$ **—**	$ **317.0**

$ in millions	Year ended December 31, 2014				
	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 (East Bend)	$ 14.2	$ —	$ —	$ 2.7	$ 11.5
Goodwill [(b)]					
DPLER Reporting unit	$ 135.8	$ —	$ —	$ —	$ 135.8

$ 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

(a) See Note 15 – Fixed-asset Impairment for further information
(b) See Note 7 – Goodwill and Other Intangible Assets for further information

Note 6 – 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 if they qualify under FASC 815 for accounting purposes.

At December 31, 2015, **DPL** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	**Not designated**	**MWh**	**10.2**	**—**	**10.2**
Forward Power Contracts	**Designated**	**MWh**	**1,676.7**	**(7,795.8)**	**(6,119.1)**
Forward Power Contracts	**Not designated**	**MWh**	**5,049.9**	**(1,663.0)**	**3,386.9**

At December 31, 2014, **DPL** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Not designated	MWh	10.5	—	10.5
Heating Oil Futures	Not designated	Gallons	378.0	—	378.0
Natural Gas Futures	Not designated	Dths	200.0	—	200.0
Forward Power Contracts	Designated	MWh	175.0	(2,991.0)	(2,816.0)
Forward Power Contracts	Not designated	MWh	1,725.2	(2,707.8)	(982.6)

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.

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 tables set forth the gains / (losses) recognized in AOCI and earnings related to the effective portion of derivative instruments and the gains / (losses) recognized in earnings related to the ineffective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the periods indicated:

	Years ended December 31,					
	2015		2014		2013	
$ in millions (net of tax)	**Power**	**Interest Rate Hedges**	Power	Interest Rate Hedges	Power	Interest Rate Hedges
Beginning accumulated derivative gain / (loss) in AOCI	**$ 0.2**	**$ 18.3**	$ 1.4	$ 19.2	$ (3.0)	$ 0.5
Net gains / (losses) associated with current period hedging transactions	**18.2**	**—**	(19.0)	—	1.0	18.7
Net gains / (losses) reclassified to earnings:						
Interest Expense	**—**	**(0.8)**	—	(0.9)	—	—
Revenues	**(12.0)**	**—**	18.3	—	2.1	—
Purchased Power	**2.8**	**—**	(0.5)	—	1.3	—
Ending accumulated derivative gain in AOCI	**$ 9.2**	**$ 17.5**	$ 0.2	$ 18.3	$ 1.4	$ 19.2
Net gains / (losses) associated with the ineffective portion of the hedging transaction						
Interest Expense	**$ —**	**$ —**	$ —	$ —	$ —	$ 0.8
Portion expected to be reclassified to earnings in the next twelve months [(a)]	**$ 5.9**	**$ (0.8)**				
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**36**	**—**				

(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.

Derivatives not designated as hedges

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, 2015, 2014 and 2013:

	Year ended December 31, 2015				
$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized loss	**$ 0.4**	**$ 0.3**	**$ (6.4)**	**$ 0.1**	**$ (5.6)**
Realized gain / (loss)	**(0.3)**	**(0.2)**	**(9.8)**	**(0.1)**	**(10.4)**
Total	**$ 0.1**	**$ 0.1**	**$ (16.2)**	**$ —**	**$ (16.0)**
Recorded on Balance Sheet:					
Regulatory asset	**$ 0.1**	**$ —**	**$ —**	**$ —**	**$ 0.1**
Recorded in Income Statement: gain / (loss)					
Purchased Power	**—**	**0.1**	**(43.6)**	**—**	**(43.5)**
Revenue	**—**	**—**	**27.4**	**—**	**27.4**
Total	**$ 0.1**	**$ 0.1**	**$ (16.2)**	**$ —**	**$ (16.0)**

	Year ended December 31, 2014				
$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain	$ (0.6)	$ (0.8)	$ (1.5)	$ (0.1)	$ (3.0)
Realized gain	(0.1)	0.7	(3.6)	(0.1)	(3.1)
Total	$ (0.7)	$ (0.1)	$ (5.1)	$ (0.2)	$ (6.1)
Recorded on Balance Sheet:					
Regulatory asset	$ (0.1)	$ —	$ —	$ —	$ (0.1)
Recorded in Income Statement: gain / (loss)					
Purchased Power	—	(0.1)	(5.1)	(0.2)	(5.4)
Fuel	(0.6)	—	—	—	(0.6)
Total	$ (0.7)	$ (0.1)	$ (5.1)	$ (0.2)	$ (6.1)

$ in millions	Heating Oil	FTRs	Power	Total
	Year ended December 31, 2013			
Derivatives not designated as hedging instruments				
Change in unrealized gain / (loss)	$ —	$ 0.3	$ 0.6	$ 0.9
Realized gain / (loss)	0.1	1.2	1.1	2.4
Total	$ 0.1	$ 1.5	$ 1.7	$ 3.3
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

The following tables show the fair value, balance sheet classification and hedging designation of **DPL's** derivative instruments at December 31, 2015 and 2014.

Fair Values of Derivative Instruments

December 31, 2015

$ 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	Designated	$ 16.2	$ (7.1)	$ —	$ 9.1
Forward power contracts	Not designated	7.3	(5.5)	—	1.8
FTRs	Not designated	0.2	(0.2)	—	—
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Designated	3.0	(2.4)	—	0.6
Forward power contracts	Not designated	4.0	(2.7)	—	1.3
Total assets		$ 30.7	$ (17.9)	$ —	$ 12.8
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Designated	$ 7.1	$ (7.1)	$ —	$ —
Forward power contracts	Not designated	14.5	(5.5)	(8.0)	1.0
FTRs	Not designated	0.5	(0.2)	—	0.3
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Designated	2.7	(2.4)	—	0.3
Forward power contracts	Not designated	2.7	(2.7)	—	—
Total liabilities		$ 27.5	$ (17.9)	$ (8.0)	$ 1.6

(a) Includes credit valuation adjustment.

Fair Values of Derivative Instruments

December 31, 2014

$ 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	Designated	$ 5.6	$ (2.0)	$ —	$ 3.6
Forward power contracts	Not designated	5.5	(3.4)	—	2.1
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Designated	0.3	(0.3)	—	—
Forward power contracts	Not designated	3.5	(0.9)	—	2.6
Total assets		$ 14.9	$ (6.6)	$ —	$ 8.3
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Designated	$ 2.1	$ (2.0)	$ —	$ 0.1
Forward power contracts	Not designated	7.5	(3.4)	(4.1)	—
FTRs	Not designated	0.6	—	—	0.6
Heating Oil Futures	Not designated	0.4	—	(0.4)	—
Natural Gas	Not designated	0.1	—	(0.1)	—
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Designated	0.6	(0.3)	(0.3)	—
Forward power contracts	Not designated	0.9	(0.9)	—	—
Total liabilities		$ 12.2	$ (6.6)	$ (4.9)	$ 0.7

(a) Includes credit valuation adjustment.

As of December 31, 2014, the above table includes Forward power contracts in a short-term asset position of $11.1 million. This table does not include a short-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.

Credit risk-related contingent features

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. 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, 2015 is $27.5 million. This amount is offset by $8.0 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 $17.9 million. Since our debt is below investment grade, we could have to post collateral for the remaining $1.6 million.

Note 7 – Goodwill and Other Intangible Assets

Goodwill

The following table summarizes the changes in Goodwill by reportable segment for the years ended December 31, 2015, 2014 and 2013:

$ in millions	DP&L Reporting Unit	DPLER Reporting Unit	Total
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
Goodwill impairments during 2014	$ —	$ (135.8)	$ (135.8)
Balance at December 31, 2014			
Goodwill	$ 2,440.5	$ 135.8	$ 2,576.3
Accumulated impairment losses	(2,123.5)	(135.8)	(2,259.3)
Net balance at December 31, 2014	$ 317.0	$ —	$ 317.0
Goodwill impairments during 2015	$ (317.0)	$ —	$ (317.0)
Balance at December 31, 2015			
Goodwill	$ 2,440.5	$ 135.8	$ 2,576.3
Accumulated impairment losses	(2,440.5)	(135.8)	(2,576.3)
Net balance at December 31, 2015	$ —	$ —	$ —

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 included **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. Goodwill represented the value assigned at the Merger date, as adjusted for subsequent changes in the purchase price allocation, less recognized impairments.

DPLER Reporting Unit

During the first quarter of 2014, we performed an interim impairment test on the $135.8 million in goodwill at our DPLER reporting unit. During the second quarter of 2014, we finalized the work to determine the implied fair value for the DPLER reporting unit. There were no further adjustments to the full impairment of $135.8 million recognized in the first quarter. DPLER was sold on January 1, 2016 and is presented in discontinued operations on the Consolidated Statement of Operations. See Note 16 – Discontinued Operations for additional information.

DP&L Reporting Unit

During the fourth quarter of 2015, **DPL** performed its annual goodwill impairment test and recognized a goodwill impairment at its DP&L reporting unit of $317.0 million. The reporting unit failed Step 1 as its fair value was less than its carrying amount, which was primarily due to a decrease forecasted in dark spreads that were driven by decreases in projected forward power prices, and lower than expected revenues from the CP product. 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 forward commodity price curves, expected revenues from the new CP product, and planned environmental expenditures. In Step 2, goodwill was determined to have no implied fair value after the hypothetical purchase price allocation under the accounting guidance for business combinations; therefore, a full impairment of the remaining goodwill balance of $317.0 million was recognized. The goodwill associated with the Merger is not deductible for tax purposes. Accordingly, there is no financial statement tax benefit related to the impairment.

During the fourth quarter of 2013, **DPL** performed its annual goodwill impairment test and recognized a goodwill impairment at its DP&L reporting unit 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.

The goodwill associated with the Merger is not deductible for tax purposes. Accordingly, there is no cash or financial statement tax benefit related to the impairment.

Note 8 – Debt

Long-term debt

$ in millions	Interest Rate	Maturity	December 31, 2015	December 31, 2014
First mortgage bonds	1.875%	2016	$ 445.0	$ 445.0
Pollution control series	4.7%	2028	—	35.3
Pollution control series	4.8%	2034	—	179.1
Pollution control series	4.8%	2036	100.0	100.0
Pollution control series - rates from: 0.02% - 0.12% and 0.04% - 0.15% (a)		2040	—	100.0
Pollution control series - rates from: 1.13% - 1.17%		2020	200.0	—
U.S. Government note	4.2%	2061	18.1	18.2
Unamortized debt discounts and premiums, net			(3.6)	(2.8)
Total long-term debt at subsidiary			759.5	874.8
Bank term loan - rates from: 2.44% - 2.67% and 2.41% - 2.44% (a)		2020	125.0	160.0
Senior unsecured bonds	6.5%	2016	130.0	130.0
Senior unsecured bonds	6.75%	2019	200.0	200.0
Senior unsecured bonds	7.25%	2021	780.0	780.0
Note to DPL Capital Trust II (b)	8.125%	2031	15.6	15.6
Unamortized debt discounts and premiums, net			(0.7)	(0.7)
Subtotal			$ 2,009.4	$ 2,159.7
Less: current portion			(574.9)	(20.1)
Total			1,434.5	2,139.6

(a) Range of interest rates for the years ended December 31, 2015 and 2014, respectively.
(b) Note payable to related party. See Note 13 – Related Party Transactions for additional information.

At December 31, 2015, maturities of long-term debt are summarized as follows:

Due within the years ending December 31, $ in millions		
2016	$	575.1
2017		25.1
2018		25.1
2019		225.2
2020		250.2
Thereafter		913.0
		2,013.7
Unamortized discounts and premiums, net		(4.3)
Total long-term debt	$	2,009.4

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

Significant transactions

On July 1, 2015, the $35.3 million of **DP&L's** 4.7% pollution control bonds due January 2028 and $41.3 million of **DP&L's** 4.8% pollution control bonds due January of 2034 were called at par and were redeemed with cash.

On July 31, 2015, **DP&L** refinanced its revolving credit facility. The new facility has a $175.0 million borrowing limit, with a $50.0 million letter of credit sublimit, a feature that provides **DP&L** the ability to increase the size of the facility by an additional $100.0 million and maturity date of July 2020. At December 31, 2015, there were two letters of credit in the amount of $1.4 million outstanding, with the remaining $173.6 million available to **DP&L**. Fees associated with this revolving credit facility were not material during the years ended December 31, 2015 or 2014. Prior to refinancing the facility on July 31, 2015, this facility had a $300.0 million borrowing limit, a five-year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature that provided **DP&L** the ability to increase the size of the facility by an additional $100.0 million.

On August 3, 2015, **DP&L** called $100.0 million of variable rate pollution control bonds due November 2040, terminated the amended standby letter of credit facilities that supported these pollution control bonds, and called $137.8 million of 4.8% pollution control bonds due January of 2034. **DP&L** also used cash to redeem $37.8 million of these bonds and refinanced the $200.0 million balance, with new variable interest rate pollution control bonds secured by first mortgage bonds in an equivalent amount. In connection with the sale of the new pollution control bonds, **DP&L** entered into a certain Bond Purchase and Covenants Agreement, dated as of August 1, 2015, containing representations, warranties, covenants and defaults consistent with those contained in the revolving credit facilities loan documents of **DP&L**.

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. Substantially concurrent with this transaction, **DP&L** redeemed $470.0 million of previously outstanding first mortgage bonds.

On July 31, 2015, **DPL** refinanced its revolving credit facility. The new facility has a total size of $205.0 million, a $200.0 million letter of credit sublimit, a feature that provides **DPL** the ability, under certain circumstances, to increase the size of the facility by an additional $95.0 million and a maturity date of July 2020. **DPL's** new credit facility also has a springing maturity feature providing that if, before July 1, 2019, **DPL** has not refinanced its senior unsecured bonds due October 2019 to have a maturity date that is at least six months later than July 31, 2020, then the maturity of this facility shall be July 1, 2019. This facility is secured by a pledge of common stock that **DPL** owns in **DP&L**, limited to the amount permitted to be pledged under certain Indentures dated October 3, 2011 and October 6, 2014 between **DPL** and Wells Fargo Bank, NA and U.S. Bank National Association, respectively, as Trustee and a limited recourse guarantee by DPLE secured by mortgages on assets of DPLE. At December 31, 2015, there were two letters of credit in the amount of $3.0 million outstanding under this facility, with the remaining

$202.0 million of the revolving credit facility remaining available to **DPL**. Fees associated with this facility were not material during the years ended December 31, 2015 or 2014.

Prior to refinancing the facility on July 31, 2015, this facility was unsecured and had a borrowing limit of $100.0 million with a $100.0 million letter of credit sublimit, was able to be increased in size by **DPL** by an additional $50.0 million and had a five-year term expiring on May 10, 2018; with a springing maturity, meaning that if **DPL** had not refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then the maturity of this facility would have been July 15, 2016.

Also on July 31, 2015, **DPL** refinanced its term loan, paying down the outstanding amount of $160.0 million using proceeds from the new term loan of $125.0 million and a combination of cash on hand and draws on short term credit facilities. The new term loan extends the term to July of 2020, pushing back required principal payments to 2017, and providing a mechanism for **DPL** to request additional term loans to refinance existing indebtedness. The new term loan has a springing maturity feature providing that if, before July 1, 2019, **DPL** has not refinanced its senior unsecured bonds due October 2019 to have a maturity date that is at least six months later than July 31, 2020, then the maturity of this facility shall be July 1, 2019. This facility is secured by a pledge of common stock that **DPL** owns in **DP&L**, limited to the amount permitted to be pledged under certain Indentures dated October 3, 2011 and October 6, 2014 between **DPL** and Wells Fargo Bank, NA and U.S. Bank National Association, respectively, as Trustee and a limited recourse guarantee by DPLE secured by mortgages on assets of DPLE. The new term loan has a springing maturity feature providing that if, before July 1, 2019, **DPL** has not refinanced its senior unsecured bonds due October 2019 to have a maturity date that is at least six months later than July 31, 2020, then the maturity of this facility shall be July 1, 2019.

In October 2014, **DPL** repaid $5.0 million of the note due to Capital Trust II, which used the funds to repurchase securities in the open market at a slight premium. Subsequent to repurchasing these securities, Capital Trust II immediately retired them.

In connection with the closing of the Merger, **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 $20.0 million of both the first and second tranche of senior unsecured notes and immediately retired them.

In October 2014, **DPL** closed a $200.0 million issuance of senior unsecured bonds. These new bonds were priced at 6.75% and mature on October 1, 2019. Proceeds from the issuance, in addition to a draw on the **DPL** revolving line of credit and cash on hand, were used to settle a tender offer for $300.0 million of the 6.50% senior unsecured notes maturing October 15, 2016. After this transaction, the DPL Inc. 6.5% Senior Notes due 2016 had an outstanding principle balance of $130.0 million

On January 6, 2016, **DPL** issued a Notice of Partial Redemption to the Trustee (Wells Fargo Bank N.A.) on the DPL Inc. 6.5% Senior Notes due 2016 (a component of the Dolphin Subsidiary II, Inc. debt). **DPL** notified the trustee that it was calling $73.0 million of the $130.0 million outstanding principal amount of these notes. The record date of this redemption was January 21, 2016, and the redemption date was February 5, 2016. These bonds were redeemed at par plus accrued interest and a make-whole premium of $2.4 million.

Debt covenants and restrictions

DP&L's unsecured revolving credit agreement and Bond Purchase and Covenants Agreement (financing document entered into in connection with the sale of the new $200.0 million of variable rate pollution control bonds, dated as of August 1, 2015, containing representations, warranties, covenants and defaults consistent with those contained in the revolving credit facilities loan documents of **DP&L**) have two financial covenants. The first measures Total Debt to Total Capitalization and 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. The second financial covenant measures EBITDA to Interest Expense. 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.

DPL's revolving credit agreement and 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.

As of December 31, 2015, **DP&L** and **DPL** were in compliance with all debt covenants, including the financial covenants described above.

DP&L does not have any meaningful restrictions in its debt financing documents prohibiting dividends to its parent, **DPL**. **DPL's** secured revolving credit agreement, secured term loan, and senior unsecured notes due 2019 restrict dividend payments from **DPL** to AES, such that **DPL** cannot make dividend payments unless at the time of, and/or as a result of, the distribution, **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, 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 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, 2015, **DPL's** leverage ratio was at 1.03 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, as of December 31, 2015, **DPL** was prohibited under each of these agreements from making a distribution to its shareholder or making a loan to any of its affiliates (other than its subsidiaries).

Note 9 – Income Taxes

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

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Computation of tax expense			
Federal income tax expense / (benefit)[(a)]	**$ (81.0)**	$ 25.4	$ (71.7)
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**(0.1)**	0.8	1.1
Depreciation of AFUDC - Equity	**(3.5)**	(3.4)	(3.2)
Investment tax credit amortized	**(0.5)**	(0.5)	(0.5)
Section 199 - domestic production deduction	**(4.1)**	(1.1)	(4.1)
Non-deductible goodwill impairment	**111.0**	—	107.2
Accrual (settlement) for open tax years	**—**	(6.6)	(8.8)
Other, net [(b)]	**(1.8)**	0.8	(0.2)
Total tax expense	**$ 20.0**	$ 15.4	$ 19.8
Components of tax expense			
Federal - current	**$ 30.1**	$ (5.2)	$ (2.5)
State and Local - current	**0.8**	0.4	—
Total current	**30.9**	(4.8)	(2.5)
Federal - deferred	**(9.9)**	19.6	20.6
State and local - deferred	**(1.0)**	0.6	1.7
Total deferred	**(10.9)**	20.2	22.3
Total tax expense	**$ 20.0**	$ 15.4	$ 19.8

Effective and Statutory Rate Reconciliation

The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to **DPL's** effective tax rate, as a percentage of income from continuing operations before taxes for the years ended December 31, 2015, 2014 and 2013:

	Years ended December 31,		
	2015	2014	2013
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
State taxes, net of Federal tax benefit	**0.1 %**	1.1 %	(0.6)%
AFUDC - Equity	**1.5 %**	(4.7)%	1.5 %
Amortization of investment tax credits	**0.2 %**	(0.7)%	0.2 %
Section 199 - domestic production deduction	**1.8 %**	(1.6)%	2.0 %
Non-deductible goodwill impairment	**(48.0)%**	— %	(52.1)%
Other, net	**0.8 %**	(7.9)%	4.3 %
Effective tax rate	**(8.6)%**	21.2 %	(9.7)%

Deferred Income Taxes

Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and (b) operating loss carryforwards. These items are stated at the enacted tax rates that are expected to be in effect when taxes are actually paid or recovered. Investment tax credits related to utility property have been deferred and are being amortized over the estimated useful lives of the related property.

Components of Deferred Tax Assets and Liabilities

	December 31,	
$ in millions	**2015**	2014
Net non-current Assets / (Liabilities)		
Depreciation / property basis	**$ (539.8)**	$ (548.2)
Income taxes recoverable	**(12.0)**	(14.8)
Regulatory assets	**(10.6)**	(18.0)
Investment tax credit	**0.7**	1.5
Compensation and employee benefits	**3.1**	3.2
Intangibles	**(8.4)**	(7.0)
Long-term debt	**(1.1)**	(1.5)
Other *(c)*	**(0.6)**	(2.5)
Net non-current liabilities	**$ (568.7)**	$ (587.3)
Net current Assets / (Liabilities) *(d)*		
Other	**$ —**	$ 1.1
Net current assets / (liabilities)	**$ —**	$ 1.1

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

(b) Includes expense of $0.2 million, $0.4 million and $0.0 million in the years ended December 31, 2015, 2014, and 2013, respectively, of income tax related to adjustments from prior years.

(c) The Other non-current liabilities caption includes deferred tax assets of $26.0 million in 2015 and $27.1 million in 2014 related to state and local tax net operating loss carryforwards, net of related valuation allowances of $17.2 million in 2015 and $18.9 million in 2014. These net operating loss carryforwards expire from 2016 to 2030.

(d) Amounts are included within Other prepayments and current assets and Other current liabilities on the Consolidated Balance Sheet of **DPL** at December 31, 2014.

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.

	Years ended December 31,		
$ in millions	**2015**	2014	2013
Tax expense / (benefit)	**$ 6.3**	$ (9.1)	$ 15.4

Uncertain Tax Positions
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 December 31, 2013	$ 8.8
Calendar 2014	
Tax positions taken during prior period	2.8
Lapse of Statute of Limitations	(8.6)
Balance at December 31, 2014	3.0
Calendar 2015	
Tax positions taken during prior period	—
Lapse of Statute of Limitations	—
Balance at December 31, 2015	$ 3.0

Of the December 31, 2015 balance of unrecognized tax benefits, $0.9 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 amounts accrued as well as the expense / (benefit) recorded were not material for the years ended December 31, 2015, 2014 and 2013.

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 statute 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 in 2013.

Note 10 – Benefit Plans

Defined contribution plans
DP&L sponsors two defined contribution plans. One is for non-union employees (the management plan) and one is for collective bargaining employees (the union plan). Both plans are qualified under Section 401 of the Internal Revenue Code.

Certain non-union employees become eligible to participate in the management plan on the first day of the month following the first full calendar month of employment; provided the employee worked at least 160 hours in that calendar month. Union employees become eligible to participate in the union plan on the first day of the first month following 30 days of employment. Effective January 1, 2016, employees in both plans are eligible to participate upon date of hire.

Participants may elect to contribute up to 85% of eligible compensation to their plan. Non-union participant contributions are matched 100% on the first 1% of eligible compensation and 50% on the next 5% of eligible compensation and they are fully vested in their employer contributions after 2 years of service. Union participant contributions are matched 150% but are capped at $2,100 for 2015 and they are fully vested in their employer contributions after 3 years of service. All participants are fully vested in their own contributions.

For the years ended December 31, 2015, 2014 and 2013, **DP&L's** contributions to all defined contribution plans were $4.8 million, $4.7 million and $4.8 million per year, respectively.

Defined benefit plans
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 January 1, 2014, the Service Company began providing services including accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including among other companies, **DPL** and **DP&L**. 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 has an immaterial unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. We also include our net liability to our partners related to our share of their pension costs within Pension, retiree and other benefits on our Consolidated Balance Sheets.

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.

Postretirement benefits
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.

The following tables set forth the changes in our pension and postemployment benefit plans' obligations and assets recorded on the balance sheets at December 31, 2015 and 2014. The amounts presented in the following tables for pension obligations 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 obligations include both health and life insurance benefits.

$ in millions	Pension	
	Years ended December 31,	
	2015	2014
Change in benefit obligation		
Benefit obligation at January 1	$ **443.8**	$ 370.5
Service cost	**7.1**	5.9
Interest cost	**17.3**	17.5
Plan amendments	**—**	6.8
Actuarial (gain) / loss	**(34.5)**	67.3
Benefits paid	**(22.9)**	(24.2)
Benefit obligation at December 31	**410.8**	443.8
Change in plan assets		
Fair value of plan assets at January 1	**371.7**	349.1
Actual return on plan assets	**(8.8)**	46.4
Contributions to plan assets	**5.4**	0.4
Benefits paid	**(22.9)**	(24.2)
Fair value of plan assets at December 31	**345.4**	371.7
Funded status of plan	$ **(65.4)**	$ (72.1)
	December 31,	
Amounts recognized in the Balance sheets	**2015**	2014
Current liabilities	$ **(0.4)**	$ (0.4)
Non-current liabilities	**(65.0)**	(71.7)
Net liability at December 31,	$ **(65.4)**	$ (72.1)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax		
Components:		
Prior service cost	$ **12.0**	$ 14.1
Net actuarial loss	**94.7**	103.4
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	$ **106.7**	$ 117.5
Recorded as:		
Regulatory asset	$ **91.1**	$ 99.0
Regulatory liability	**—**	—
Accumulated other comprehensive income	**15.6**	18.5
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	$ **106.7**	$ 117.5

$ in millions	Postretirement	
	Years ended December 31,	
	2015	2014
Change in benefit obligation		
Benefit obligation at beginning of period	**$ 19.6**	$ 19.7
Service cost	**0.2**	0.2
Interest cost	**0.6**	0.8
Actuarial (gain) / loss	**(1.1)**	0.2
Benefits paid	**(1.5)**	(1.3)
Benefit obligation at end of period	**17.8**	19.6
Change in plan assets		
Fair value of plan assets at beginning of period	**3.3**	3.7
Contributions to plan assets	**1.0**	0.9
Benefits paid	**(1.5)**	(1.3)
Fair value of plan assets at end of period	**2.8**	3.3
Funded status of plan	**$ (15.0)**	$ (16.3)

	December 31,	
	2015	2014
Amounts recognized in the Balance sheets		
Current liabilities	**$ (0.4)**	$ (0.5)
Non-current liabilities	**(14.6)**	(15.8)
Net liability at December 31,	**$ (15.0)**	$ (16.3)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax		
Components:		
Prior service cost	**$ 0.3**	$ 0.4
Net actuarial gain	**(5.5)**	(5.0)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ (5.2)**	$ (4.6)
Recorded as:		
Regulatory asset	**$ 0.3**	$ 0.4
Regulatory liability	**(5.1)**	(4.8)
Accumulated other comprehensive income	**(0.4)**	(0.2)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ (5.2)**	$ (4.6)

The accumulated benefit obligation for our defined benefit pension plans was $401.2 million and $431.0 million at December 31, 2015 and 2014, respectively.

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

Net Periodic Benefit Cost - Pension

$ in millions	Years ended December 31, 2015	2014	2013
Service cost	**$ 7.1**	$ 5.9	$ 7.2
Interest cost	**17.3**	17.5	15.6
Expected return on assets [(a)]	**(22.6)**	(22.9)	(23.3)
Amortization of unrecognized:			
Actuarial gain	**5.8**	3.4	4.9
Prior service cost	**2.0**	1.5	1.5
Net periodic benefit cost	**$ 9.6**	$ 5.4	$ 5.9

Net Periodic Benefit Cost - Postretirement

$ in millions	Years ended December 31, 2015	2014	2013
Service cost	**$ 0.2**	$ 0.2	$ 0.2
Interest cost	**0.6**	0.8	0.8
Expected return on assets [(a)]	**(0.1)**	(0.2)	(0.1)
Amortization of unrecognized:			
Actuarial loss	**(0.6)**	(0.6)	(0.5)
Prior service cost	**0.1**	—	—
Net periodic benefit cost	**$ 0.2**	$ 0.2	$ 0.4

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, 2015	2014	2013
Net actuarial loss / (gain)	**$ (3.0)**	$ 43.8	$ (12.0)
Prior service cost	**—**	6.8	—
Reversal of amortization item:			
Net actuarial loss	**(5.8)**	(3.4)	(4.9)
Prior service cost	**(2.0)**	(1.5)	(1.5)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (10.8)**	$ 45.7	$ (18.4)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ (1.2)**	$ 51.1	$ (12.5)

Postretirement

$ in millions	Years ended December 31, 2015	2014	2013
Net actuarial loss / (gain)	$ **(1.1)**	$ 0.4	$ (2.0)
Reversal of amortization item:			
Net actuarial gain	**0.6**	0.6	0.5
Prior service cost	$ **(0.1)**	$ —	$ —
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **(0.6)**	$ 1.0	$ (1.5)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **(0.4)**	$ 1.2	$ (1.1)

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2016 are:

$ in millions	Pension	Postretirement
Actuarial gain / (loss)	$ 4.3	$ (0.6)
Prior service cost	$ 1.9	$ 0.1

Assumptions

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.

At December 31, 2015, we are maintaining our long term rate of return assumption of 6.50% for pension plan assets. In addition, we are decreasing our long-term rate of return assumption to 3.90% from 4.50% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our long-term portfolio mixes. Also, at December 31, 2015, we have increased our assumed discount rate to 4.49% from 4.02% for pension and to 4.10% from 3.71% for postemployment benefits expense to reflect current duration-based yield curve discount rates. A one percent increase in the rate of return assumption for pension would result in a decrease in pension expense of approximately $3.5 million. A one percent decrease in the rate of return assumption for pension would result in an increase in pension expense of approximately $3.5 million. A 25 basis point increase in the discount rate for pension would result in a decrease of approximately $0.2 million to 2016 pension expense. A 25 basis point decrease in the discount rate for pension would result in an increase of approximately $0.3 million to 2016 pension expense. A one percent change in the assumed health care cost trend rate would affect postemployment benefit costs by less than $1.0 million.

In determining the discount rate to use for valuing liabilities, we used a market yield curve on high-quality fixed income investments as of December 31, 2015. We project the expected benefit payments under the plan based on participant data and based on certain assumptions concerning mortality, retirement rates, termination rates, etc. The expected benefit payments for each year are then discounted back to the measurement date using the appropriate spot rate for each half-year from the yield curve, thereby obtaining a present value of all expected future benefit payments using the yield curve. Finally, an equivalent single discount rate is determined which produces a present value equal to the present value determined using the full yield curve.

Effective January 1, 2016, we will apply a disaggregated discount rate approach for determining service cost and interest cost for our defined benefit pension plans and postretirement plans. See Note 1 – Overview and Summary of Significant Accounting Policies for more information.

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.

The weighted average assumptions used to determine benefit obligations at December 31, 2015, 2014 and 2013 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2015	2014	2013	**2015**	2014	2013
Discount rate for obligations	**4.49%**	4.02%	4.86%	**4.10%**	3.71%	4.58%
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, 2015, 2014 and 2013 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2015	2014	2013	**2015**	2014	2013
Discount rate	**4.02%**	4.86%	4.04%	**3.81%**	4.51%	4.58%
Expected rate of return on plan assets	**6.50%**	6.75%	6.75%	**4.50%**	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, 2015, 2014 and 2013 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2015	2014	2013	**2015**	2014	2013
Pre - age 65						
Current health care cost trend rate	**6.97%**	7.75%	8.00%	**6.85%**	6.97%	7.75%
Year trend reaches ultimate	**2029**	2023	2019	**2036**	2029	2023
Post - age 65						
Current health care cost trend rate	**6.97%**	6.75%	7.50%	**6.85%**	6.97%	6.75%
Year trend reaches ultimate	**2029**	2021	2018	**2036**	2029	2021
Ultimate health care cost trend rate	**4.50%**	5.00%	5.00%	**4.50%**	4.50%	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	$ —
Benefit obligation	$ 0.8	$ (0.7)

Pension 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, as well as short-term tactical asset allocation guidelines, are determined by a Risk/Advisory Committee and approved by a Fiduciary Committee. These allocations take into account the Plan's long-term objectives. The long-term target allocations for plan assets are 18% – 38% for equity securities and 58% – 86% for fixed income securities. 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.

Tactically, the committees, on a short-term basis, will make asset allocations that are outside the long-term allocation guidelines. The short-term allocation positions are likely to not exceed one-year in duration. In addition to the equity and fixed income investments, the short-term allocation may also include a relatively small allocation to alternative investments. The plan currently has a small allocation to a core property fund, as well as a small allocation to a hedge fund.

Most of our Plan assets are measured using quoted, observable prices which are considered Level One inputs in the Fair Value Hierarchy. The Core property collective fund and the Common collective fund are measured using Level Two inputs that are quoted prices for identical assets in markets that are less active.

The following table summarizes our target pension plan allocation for 2015:

		Percentage of plan assets as of December 31,	
Asset category	Long-Term Mid-Point Target Allocation	2015	2014
Equity Securities	28%	17%	18%
Debt Securities	72%	67%	69%
Real Estate	—%	9%	7%
Other	—%	7%	6%

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11/30/2020 2:16:10 PM

in

Case No(s). 20-1651-EL-AIR, 20-1652-EL-AAM, 20-1653-EL-ATA

Summary: Application Book I - Application and Supplemental, Volume 5 of 11 electronically filed by Mr. Jeffrey S Sharkey on behalf of The Dayton Power and Light Company