FILE

LARGE FILING SEPARATOR SHEET

CASE NUMBER 12-426-EL-SSO 12-429-EL-WVR
12-427-EL-ATA 12-672-EL-RDR
12-428-EL-AAM

FILE DATE 3-1-2013

SECTION 1 of 2

NUMBER OF PAGES 200

DESCRIPTION OF DOCUMENT
DIRECT TESTIMONY of KEVIN. M. MURRAY

FILE

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Market Rate Offer.	)))	Case No. 12-426-EL-SSO
In the Matter of the Application of The Dayton Power and Light Company for Approval of Revised Tariffs.	)))	Case No. 12-427-EL-ATA
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DIRECT TESTIMONY OF KEVIN M. MURRAY
ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO

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March 1, 2013

Attorneys for Industrial Energy Users-Ohio

PUBLIC

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DIRECT TESTIMONY OF KEVIN M. MURRAY
ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO

I. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Kevin M. Murray. My business address is 21 East State Street, 17th Floor, Columbus, Ohio 43215-4228.

Q2. By whom are you employed and in what position?

A2. I am employed as a Technical Specialist by McNees Wallace & Nurick LLC ("McNees") and serve as the Executive Director of the Industrial Energy Users-Ohio ("IEU-Ohio"). I am providing testimony on behalf of IEU-Ohio.

Q3. Please describe your educational background.

A3. I graduated from the University of Cincinnati in 1982 with a Bachelor of Science degree in Metallurgical Engineering.

Q4. Please describe your professional experience.

A4. I have been employed by McNees for 15 years where I focus on helping IEU-Ohio members address issues that affect the price and availability of utility services. I have also been actively involved, on behalf of commercial and industrial customers, in the formation of regional transmission operators ("RTOs") and the organization of regional electricity markets from both the supply-side and demand-side perspective. I serve as an end-use customer sector representative on the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO") Advisory Committee and I have been actively involved in MISO working groups that focus on various issues since 1999. Prior to joining McNees, I was employed by the law firm of Kegler, Brown, Hill & Ritter ("KBH&R") in a similar capacity. Prior to joining KBH&R, I spent 12 years with The Timken Company, a specialty steel and roller bearing manufacturer. While at The Timken Company, I worked within a group that focused on meeting the electricity and natural gas requirements for facilities in the United States. I also spent several years in supervisory positions within The Timken Company's steelmaking operations.

Q5. Have you previously testified before the Public Utilities Commission of Ohio ("Commission")?

A5. Yes. The proceedings before the Commission in which I have submitted expert testimony are identified in Exhibit KMM-1.

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to recommend that the Commission deny The Dayton Power & Light Company's ("DP&L") request to establish the Service Stability Rider ("SSR") and Switching Tracker ("ST"). As discussed in the direct testimony of IEU-Ohio witness Joseph G. Bowser, DP&L has not demonstrated that the financial integrity of the electric distribution utility ("EDU") is threatened. Therefore, DP&L's financial integrity claims lack merit and do not provide any basis to approve the SSR and ST. Additionally, the proposed SSR and ST are contrary to state policy, and as I understand, state law, because they are designed to provide an anticompetitive subsidy flowing from noncompetitive retail electric service to a competitive retail electric service through distribution rates.

Additionally, I recommend the Commission find that DP&L's proposed electric security plan ("ESP") is not more favorable in the aggregate than a market rate offer ("MRO") because the ESP is much more expensive than the MRO option. Based upon the assumed standard service offer ("SSO") load reflected in Second

Revised Exhibit RJM-1 of DP&L witness R. Jeffrey Malinak and the elimination of the Rate Stabilization Charge ("RSC"), the ESP is less favorable than an MRO by $568 million between June 2013 and May 2018 for customers, ignoring the impacts of the proposed ST. If switching grows beyond levels as of August 30, 2012 and if DP&L's ST is approved (which I do not recommend), the ESP versus MRO comparison gets worse. At an assumed switching level of 70%, the ESP is less favorable than an MRO by $668 million between June 2013 and May 2018 for customers. Even Mr. Malinak's analysis supports a conclusion that the as-proposed ESP is less favorable than an MRO by a considerable margin when the real impacts of the proposed ESP are recognized. While Mr. Malinak's Second Revised Exhibit RJM-1 shows an ESP versus MRO price benefit of $119.98 million over the term of the proposed ESP, he treats the non-bypassable SSR as a wash under all scenarios, which ignores the true impact of DP&L's overall ESP proposal on customers. The proposed SSR, which would replace the current RSC, results in incremental non-bypassable charges to customers that would provide incremental revenues of $324 million to DP&L over the term of the proposed ESP. These incremental non-bypassable charges to customers more than offset the entire ESP price benefit claimed by Mr. Malinak ($119.98 million) during the term of the ESP.

Finally, I recommend the Commission not approve DP&L's request to split its current bypassable transmission cost recovery rider ("TCRR") into bypassable and non-bypassable components.

II. HISTORY OF THIS PROCEEDING

Q7. Are you familiar with the history of this proceeding?

A7. Yes. On March 30, 2012, DP&L submitted an application to establish an SSO in the form of an MRO. Shortly thereafter, a procedural schedule was established that initially called for an evidentiary hearing to commence on May 8, 2012. Thereafter, the procedural schedule was modified several times and the evidentiary hearing was delayed and scheduled to a later date in order to allow the parties to pursue settlement negotiations. On September 7, 2012, DP&L filed notice it was withdrawing its March 30, 2012 application. On October 5, 2012, DP&L filed a new application to establish an SSO in the form of an ESP. DP&L subsequently notified parties that it had discovered a significant error in its October 5, 2012 application that required correction. On December 12, 2012, DP&L filed a Second Revised Application for approval of an ESP ("Revised ESP").

Q8. What are the significant components of the Revised ESP?

A8. DP&L has proposed a Revised ESP for the period of January 1, 2013 through May 31, 2016, in which an increasing portion of the generation supply to provide service to non-shopping SSO customers will be set through a competitive bidding process ("CBP") and will be blended with the remaining portion of the SSO generation rate which will reflect DP&L's existing base rates. The proposed blending percentages are shown below:

Date	Existing Rates	Competitive Bid
1/1/13 to 5/31/14	**90%**	**10%**
6/1/14 to 5/31/15	**60%**	**40%**
1/1/15 to 5/31/16	**30%**	**70%**
6/1/16	**0%**	**100%**

DP&L is proposing to split its current TCRR into bypassable and non-bypassable components. DP&L has proposed to merge the Environmental Investment Rider ("EIR") into current base generation rates. DP&L is also proposing to modify its methodology for accounting for and recovery of fuel costs to reflect what it describes will be a system average cost methodology. DP&L has proposed a new non-bypassable SSR and ST as part of its ESP.

Finally, DP&L has proposed a placeholder non-bypassable Alternative Energy Rider ("AER-N") and has requested the initial rate be set at zero. DP&L plans to file support for recovery of the costs of the Yankee Solar Generating Facility through AER-N within six months of a Commission order approving the proposed ESP.

Q9. How do the issues raised by DP&L in this proceeding relate to efforts to develop competitive markets for electricity?

A9. The significance of the issues raised by DP&L's application in this proceeding can be better understood by looking more broadly at what has happened at the state and federal level to restructure the electric industry in order to address the anticompetitive structure of the industry and to allow competitive markets to serve the public interest in reasonable rates and reliable service. This broader history includes background information on determinations that have been made by the Federal Energy Regulatory Commission ("FERC").

FERC has increasingly relied upon competitive market forces to establish "just and reasonable" prices at the wholesale level in both the gas and electric sectors. As part of FERC's effort to remedy the anticompetitive electric industry structure, which was dominated by vertically-integrated investor-owned electric utilities, FERC required electric utilities to move to open access, comparable and non-discriminatory transmission service and encouraged vertically-integrated electric utilities that owned generating plants to transfer operational control of their high voltage transmission facilities to independent RTOs such as PJM Interconnection LLC ("PJM"). When Ohio enacted its electric restructuring legislation in 1999, the legislation similarly included a requirement that owners of transmission facilities transfer control of such facilities to an RTO.[1] Again, FERC's directives and policy announcements were part of FERC's effort to remedy undue discrimination in the operation of transmission facilities that occurred because vertically-integrated utilities used their operation and control of their transmission facilities to favor their generation assets.

Over time, the role of RTOs has expanded, subject to FERC's supervision and regulation, beyond the operation and control of transmission assets to remedy the anticompetitive industry structure. Today, RTOs are responsible for maintaining real time reliability of the electric grid and do so in coordination with

[1] Section 4928.12, Revised Code.

regional electricity markets. Instead of allowing vertically-integrated electric utilities to use control over "bottleneck" functions to favor their own assets and services, FERC mandated open access transmission services and authorized the creation of RTOs to facilitate the separation of ownership and control over the transmission and generation functions.

Under FERC's supervision, RTOs have done much to break the hold of vertically-integrated utilities' control over monopoly or "bottleneck" functions such as transmission and have increasingly introduced market-based approaches to maintain reliability in ways that better check the abuses that occurred in the anticompetitive vertically-integrated industry structure. The RTOs are managing the operation of regional electricity markets to secure scale and scope economies with independent market-monitoring oversight to determine if, and when, RTO or FERC intervention is needed to address anticompetitive behavior or circumstances where competition is not adequate to produce just and reasonable rates. For example, PJM began operating a regional electricity market in 1997. Currently, PJM coordinates the movement of wholesale electricity in all or parts of thirteen states (including Ohio) and the District of Columbia.

Q10. You have described the efforts at the federal level to separate ownership and control of "bottleneck" functions within the vertically-integrated electric utility industry segment known as the wholesale or sale for resale market. Please describe the means by which Ohio approached separation of ownership and control of such functions in the retail segment.

A10. The separation of ownership and control objective can be seen in numerous aspects of Ohio's approach to restructuring the retail electric market so that retail customers can exercise "customer choice" for the services or functions declared by the law or found by the Commission to be "competitive retail electric services." For example, Amended Substitute Senate Bill 3 ("SB 3") requires entities owning or operating transmission facilities to participate in RTOs like PJM that separate ownership and control of transmission functions from generation functions and maintain reliability within a broad region including Ohio.[2] As I understand SB 3, the provision of generation supply to retail customers was declared to be and is a competitive service and the Commission has authority to declare that other services are competitive. For services which are non-competitive, the Commission retained traditional ratemaking authority to authorize utilities to bill and collect for non-competitive services unless the Commission's authority is preempted.

In the case of competitive services, it is my understanding that SB 3 preserved the Commission's ability to approve prices for default service provided by an EDU such as DP&L through the SSO but precludes the Commission from regulating rates and charges for competitive services provided by competitive retail electric service ("CRES") providers based on the traditional rate base, rate of return model. It is also my understanding that SB 3 precludes an EDU from providing a competitive and non-competitive service unless the competitive service is provided through a structurally separated affiliate. In addition to

[2] Section 4928.12, Revised Code.

essentially separating the distribution, transmission and generation functions of a vertically-integrated investor-owned electric utility, it is my understanding that SB 3 requires EDUs to implement corporate separation plans approved by the Commission to guard against the challenges associated with the vertically-integrated and anticompetitive industry structure that predated electric industry restructuring.

Q11. What type of corporate separation plan was approved for DP&L?

A11. It is my understanding that SB 3 made the corporate separation requirements effective prior to the January 1, 2001 effective date of customer choice. It also required the Commission to review and address the EDU's corporate separation plan as part of the service and rate unbundling process that took place in the electric transition plan ("ETP") process.

DP&L filed its ETP in Commission Case No. 99-1687-EL-ETP. That case was resolved through a Stipulation and Recommendation accepted by the Commission. DP&L's proposed corporate separation plan was not opposed by any party in the ETP proceeding. DP&L's corporate separation plan called for it to transfer its distribution business and assets and transmission business and assets to an affiliate by January 1, 2001. DP&L generating assets would remain with DP&L, which would become an exempt wholesale generator. The Commission approved the corporate separation plan in its Finding and Order approving the ETP Stipulation and Recommendation.

Q12. Did DP&L implement the corporate separation plan approved as part of its ETP?

A12. No. DP&L elected to implement functional separation and ownership of its distribution, transmission and generation businesses to this day remain under DP&L.

III. BUSINESS RELATIONSHIP BETWEEN DP&L AND DPL RETAIL

Q13. Are you familiar with the business relationship between DP&L and DPL Retail?

A13. Yes. DP&L has two non-regulated affiliates that supply competitive retail generation services. DPL Energy Resources ("DPLER") is a competitive retail electric supplier that is actively soliciting retail customers throughout Ohio in service areas with retail choice of generation supply. DPLER has a wholly-owned subsidiary, MC Squared Energy Services, LLC ("MC2") that is a competitive retail electric generation supplier in Illinois. DPL Inc. acquired MC2 in March 2011. At times, DP&L collectively refers to DPLER and MC2 as DPL Retail.

Q14. Why is DP&L's business relationship with DPL Retail relevant to this proceeding?

A14. DP&L has claimed that Commission approval of the SSR and ST are necessary in order for DP&L to remain financially sound. However, as discussed below, DP&L's claims of impaired financial integrity are self-inflicted and are the direct result of its improper business relationship with DPL Retail, which violates both the letter and spirit of Ohio's corporate separation requirements governing the business relationships between a regulated EDU and its non-regulated affiliates.

Q15. What has been the trend of customer switching to CRES providers within DP&L's service area?

A15. As of August 30, 2012, approximately 62% of DP&L's retail load has switched to a CRES provider. DP&L has provided a forecast of incremental switching in response to interrogatories. As shown on Exhibit KMM-2, DP&L has forecasted switching will [redacted].

Q16. What portion of the switched load has been retained by DPLER?

A16. The majority of the switched load has been retained by DPLER. As shown in Exhibit KMM-3, in a November 2012 presentation at the 47th Annual Edison Electric Institute ("EEI") Financial Conference, AES Corporation reported that DPL (the parent company of DPLER) had retailed 73% of switched load. DPL has a business strategy to expand its retail customer base.

Q17. Where does DPL Retail obtain generation supply to provide service to the retail customers it serves?

A17. DPL Retail has been [redacted]

[redacted]. As shown on Exhibit KMM-4, which is DP&L's response to IEU-Ohio's Fifth Set of Interrogatories, Question Nos. 5-12, 5-13, 5-14 and 5-15, DP&L has a formal procedure to establish a transfer price for all generation sold by DP&L to DPLER. According to DP&L, the transfer price reflects the market-based supply costs to meet the full supply requirements necessary for DPLER to satisfy a retail customer's bypassable generation and transmission service. The procedure to establish the transfer price is reflected in two documents that DP&L identified in interrogatory responses as "Dayton Power-DPL Retail Transactions Transfer Price Confirms" and "DP&L-to-DPLER Transfer Price & Confirm Flow Diagram." I should note that the document title that DP&L identified in its response to IEU-Ohio interrogatories does not match the actual title on the documents produced.

Q18. Did DP&L change its business practices regarding wholesale sales of generation to DPLER?

A18. Yes. Although DP&L's transfer price associated with generation and transmission sales to DPLER currently reflects market-based price, this is a change from prior business practices. As shown on Exhibit KMM-5, which is DP&L's response to the Office of the Ohio Consumers' Counsel's ("OCC") Interrogatory No. 339, in 2010 DP&L and DPLER implemented a new wholesale supply agreement that provided for transfer prices to be at market-based rates. Prior to 2010, the wholesale sales from DP&L to DPLER were at prices that approximated DPLER's sales prices to retail customers. DP&L and DPLER implemented the new wholesale supply agreement in 2010 to meet their "business needs."

Q19. Does DPL Retail expect to [redacted]

A19. [redacted].

Q20. How are transfer prices between DP&L and DPLER established?

A20. [redacted]

[redacted].

Q21. Have you reviewed any transaction confirmation reports establishing transfer prices between DP&L and DPLER?

A21. Yes. [redacted].

Q22. Who establishes the retail price offers to customers served by DPLER?

A22. [redacted]

[redacted].

Q23. Did you identify additional concerns with the manner in which transfer pricing is established by DP&L?

A23. Yes. [redacted]

[redacted]

Q24. Do DP&L's wholesale generation sales to DPLER contribute to earnings at DP&L?

A24. [redacted]

Q25. Are the expected gross margins you identify in response to Question 24 reflected in the financial projections provided by DP&L?

A25. [redacted]

[redacted]

Q26. Does this modeling methodology accurately reflect the gross margin DP&L will realize from wholesales sales to DPLER off-system?

A26. [redacted]

Q27. Has DP&L modified its transfer pricing policies to shift generation margins from DP&L to DPLER?

A27. Yes. As shown on Exhibit KMM-18, which is a copy of DPL's 2010 10-K filing at the Securities and Exchange Commission ("SEC"),[3] prior to 2010 the transfer price between DP&L and DPLER was set at levels that approximated the DPLER retail selling price to the customer. As a result of this, the retail margin earned by DPLER was relatively low. In its 2010 10-K, DPL reported (as reflected on Page 50) that DPLER earned net income of $1.9 million in 2008 and lost $2.7 million in 2009. Following the change in transfer price methodology that was implemented in 2010, in which the transfer prices were prospectively market-based, DPL reported that DPLER earned $18.8 million in net income in 2010.

[3] The 2010 10-K report is available on the SEC website at: http://www.sec.gov/Archives/edgar/data/787250/000110465911008106/0001104659-11-008106-index.htm (last accessed February 12, 2013).

Q28. Is DPLER continuing to realize positive margins on its retail generation sales?

A28. Yes. As shown in Exhibit KMM-19, which is a copy of DPL's 2012 amended third quarter 10-Q report filed at the SEC,[4] through the third quarter of 2012, DPL reported (as reflected on Page 61) that DPLER earned net income of $17.5 million.

Q29. Are the retail margins earned by DPLER reflected in the financial projections provided by DP&L?

A29. No.

Q30. Does DP&L separately account for its different lines of business?

A30. No. As shown on Exhibit KMM-13, which is a copy of DP&L's response to Interrogatory Nos. 9-10 and 9-11 from FirstEnergy Solutions, DP&L was not able to provide historical returns on equity for its distribution, transmission and generation business segments. DP&L also was not able to provide projected returns on equity by business segment for each year of the proposed ESP.

As discussed in the direct testimony of IEU-Ohio witness J. Edward Hess, the inability of DP&L to provide return on equity values by business segment is the direct result of failing to maintain discrete accounting records by business segment and does not comply with Ohio's corporate separation requirements.

[4] The 2010 10-K report is available on the SEC website at: http://www.sec.gov/Archives/edgar/data/787250/000078725012000011/0000787250-12-000011-index.htm (last accessed February 12, 2013).

Q31. What are your conclusions regarding DP&L's business relationship with DPLER?

A31. [redacted].

IV. THE SSR AND ST SHOULD NOT BE APPROVED

Q32. What is the SSR?

A32. The SSR is a non-bypassable charge that DP&L claims is necessary to provide DP&L the opportunity to earn what DP&L believes is a reasonable return on equity over the next five years. The SSR is designed to collect $137.5 million annually during each year of the ESP.

Q33. What is the ST?

A33. The ST is a non-bypassable charge that would be triggered by any incremental switching in excess of switching levels reflected as of August 30, 2012 (62% of retail load). The revenue to be collected through the ST will be calculated by multiplying the incremental switched load by the difference between the blended SSO generation rate and the generation rate established through the competitive bidding process.

Q34. Has DP&L provided any estimate of revenue to be collected through the ST?

A34. Yes. As shown on Exhibit KMM-2, based upon assumed switching levels and the forecast results of the proposed CBP, DP&L has estimated the ST will produce [redacted] in revenue through May 2016, when the proposed ST would terminate.

Q35. Should the Commission approve the proposed SSR and ST?

A35. No. There are multiple reasons why approval of the proposed SSR and ST in this proceeding would result in unreasonable if not unlawful outcomes and, more broadly speaking, go against the structural reforms and policy objectives that are part and parcel of the effort to remedy an anticompetitive electric industry structure.

First, both the SSR and ST are contrary to the state's policies and would provide an unwarranted subsidy to DP&L's generation business, to the detriment of its competitors and shopping and non-shopping customers alike.

Second, as IEU-Ohio witness J. Edward Hess explains in his testimony, DP&L's proposed SSR and ST is really a belated, and as I understand it based on the advice of counsel, illegal request to obtain "transition revenue" well after the opportunity to submit such a claim expired. I also understand that this "transition revenue" claim was submitted by DP&L long after it surrendered its right to submit such a claim and to impose a transition charge on shopping customers.

Third, DP&L's financial integrity claims are the result of [redacted].

Q36. Does Ohio prohibit subsidies between an electric utility's regulated and non-regulated businesses?

A36. Yes. Section 4928.02 (H), Revised Code, states that it is the policy of the state to:

> Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates.

Q37. Would the SSR and ST provide DP&L an anticompetitive subsidy?

A37. Yes. Both the SSR and ST are structured as non-bypassable charges that would be levied on DP&L's distribution customers. They are designed to provide DP&L revenues to prop up the earnings associated with its generation business.

Q38. Are the proposed SSR and ST a request for an additional source of transition revenues?

A38. Yes. It may be helpful to provide some additional context to help explain my answer.

Ohio made the move to "customer choice" in 1999 with the passage of SB 3. At the time, there were parallel federal efforts to restructure the wholesale electric market and address the anticompetitive electric industry structure. These initiatives were rooted in the view that competitive markets could do a better job of advancing the public interest in reasonable prices, reliable service and innovation than traditional regulation.

SB 3 contained policy objectives and established the process by which the evolution to reliance upon competitive markets would occur for competitive services such as generation supply. As discussed earlier, Ohio's implementation of SB 3 required the unbundling or separation of the three major functions (generation or production, transmission and distribution) associated with retail electric service into separate competitive and non-competitive service components with separate prices for such unbundled components.

SB 3 established a "transition period" beginning on January 1, 2001 and ending on December 31, 2010. Within the transition period, SB 3 created a five-year market development period ("MDP") during which incumbent investor-owned utilities and customers had the opportunity to prepare for and transition to a competitive market. SB 3 directed the Commission to structure transition plans with the objective of obtaining at least 20% customer switching by the mid-point of the MDP, which could end no later than December 31, 2005.

The evolutionary approach to restructuring the retail investor-owned electric industry in Ohio, accompanied by the completion of the transitional tasks, served two important objectives. The first objective was to provide customers with certain price protections from the dysfunction that is often associated with new and immature markets until such time as the retail market was mature enough to produce "reasonable" prices. The General Assembly protected customers by specifying that the total price of electricity in effect in October 1999 would define the total price envelope within which the individual or unbundled generation, transmission and distribution prices would be established through the transition plan process.[5] SB 3 also provided residential customers an immediate benefit in the form of a five percent discount.

[5] The total bundled price for each electric rate schedule established the total rate cap, which is then divided between the functional components (generation, transmission, and distribution). Ohio provided, in Section 4928.34(A)(6), Revised Code, that such rate cap was subject to adjustment for changes in taxes, costs related to the establishment of a universal service fund ("USF"), and a temporary rider established by Section 4928.61, Revised Code. Thus, the rate cap was not an absolute cap on the total charges paid by customers during the MDP.

The second consequence of the SB 3 structure protected incumbent EDUs during the MDP (and the balance of the transition period) from potential revenue loss that might otherwise be caused by an abrupt exposure to a new and immature market. In 2001, price offers for competitive retail service were relatively low and the transition structure protected EDUs from revenue and earnings erosion. Each EDU was also provided an opportunity to protect itself in the event the EDU judged the revenue from unbundled generation prices to be above the revenue that it could obtain from providing generation services in the competitive market. The right to pursue this protection required an EDU to file a claim with the Commission for "transition revenue" (i.e., the positive difference between the unbundled default supply generation prices and prices available to the EDU for generation services provided in the market — sometimes called "stranded costs") as part of the ETP filings. If the EDU's unbundled default supply generation service prices yielded revenue less than that available in the market, this "stranded benefit" was netted against the transition revenue claim. The net, legitimate and verifiable amount of any allowable generation-related transition revenue claim had to be collected by December 31, 2010. DP&L's ETP case was ultimately resolved through a stipulation approved by the Commission. In the stipulation, the maximum allowable amount of transition revenue for DP&L was capped at $699.2 million during DP&L's market development period. DP&L agreed to forego recovery of all transition costs after December 31, 2003. *In the Matter of the Application of the Dayton Power and Light Company for Approval of its Transition Plan Pursuant to Section 4928.31,* *Revised Code and for the Opportunity to Receive Transition Revenues as Authorized Under Sections 4928.31 to 4928.40, Revised Code*, Case No. 99-1687-EL-ETP, Opinion and Order at 29 (September 21, 2000). IEU-Ohio witness J. Edward Hess also discusses this history.

Q39. Are DP&L's financial integrity claims self-inflicted?

A39. Yes. As discussed above, the [redacted].

Q40. What are your conclusions regarding the SSR and ST?

A40. The proposed SSR and ST are designed to provide DP&L an anticompetitive subsidy to prop up the earnings associated with its generation related business and should not be approved. DP&L's financial integrity claims are the result of [redacted]

[redacted].

V. ESP VERSUS MRO

Q41. What finding must the Commission make before it can approve an ESP?

A41. It is my understanding that before the Commission can approve an ESP it is required to find that the ESP as approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results than would otherwise apply under an MRO.

Q42. Are there requirements that apply to an MRO for an EDU that owned electric generating facilities as of July 31, 2008?

A42. Yes. It is my understanding that an MRO for an EDU that owns generating assets as of July 31, 2008 is required to reflect a blending of bid results with legacy ESP rates. Specifically, Section 4928.142(D), Revised Code, provides:

> The first application filed under this section by an electric distribution utility that, as of July 31, 2008, directly owns, in whole or in part, operating electric generating facilities that had been used and useful in this state shall require that a portion of that utility's standard service offer load for the first five years of the market rate offer be competitively bid under division (A) of this section as follows: ten per cent of the load in year one, not more than twenty per cent in year two, thirty per cent in year three, forty per cent in year four, and fifty per cent in year five. Consistent with those percentages, the commission shall determine the actual percentages for each year of years one through five. The standard

service offer price for retail electric generation service under this first application shall be a proportionate blend of the bid price and the generation service price for the remaining standard service offer load, which latter price shall be equal to the electric distribution utility's most recent standard service offer price, adjusted upward or downward as the commission determines reasonable, relative to the jurisdictional portion of any known and measurable changes from the level of any one or more of the following costs as reflected in that most recent standard service offer price:

(1) The electric distribution utility's prudently incurred cost of fuel used to produce electricity;

(2) Its prudently incurred purchased power costs;

(3) Its prudently incurred costs of satisfying the supply and demand portfolio requirements of this state, including, but not limited to, renewable energy resource and energy efficiency requirements;

(4) Its costs prudently incurred to comply with environmental laws and regulations, with consideration of the derating of any facility associated with those costs. In making any adjustment to the most recent standard service offer price on the basis of costs described in division (D) of this section, the commission shall include the benefits that may become available to the electric distribution utility as a result of or in connection with the costs included in the adjustment, including, but not limited to, the utility's receipt of emissions credits or its receipt of tax benefits or of other benefits, and, accordingly, the commission may impose such conditions on the adjustment to ensure that any such benefits are properly aligned with the associated cost responsibility. The commission shall also determine how such adjustments will affect the electric distribution utility's return on common equity that may be achieved by those adjustments. The commission shall not apply its consideration of the return on common equity to reduce any adjustments authorized under this division unless the adjustments will cause the electric distribution utility to earn a return on common equity that is significantly in excess of the return on common equity that is earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. Additionally, the commission may adjust the electric distribution utility's most recent standard service offer price by such just and reasonable amount that the commission determines necessary to address any emergency that threatens the utility's financial integrity or to ensure

> that the resulting revenue available to the utility for providing the standard service offer is not so inadequate as to result, directly or indirectly, in a taking of property without compensation pursuant to Section 19 of Article I, Ohio Constitution. The electric distribution utility has the burden of demonstrating that any adjustment to its most recent standard service offer price is proper in accordance with this division.

If an MRO is accepted by the Commission, it is my understanding that, beginning in the second year, the Commission may prospectively alter the blending percentages in order to mitigate any abrupt or significant change in rates.

Q43. Did DP&L evaluate whether the ESP is more favorable in the aggregate than an MRO?

A43. Yes. DP&L witness R. Jeffrey Malinak provides a comparison of the prices under the proposed ESP to an MRO (the Aggregate Price Test). Mr. Malinak also provides his estimate of other non-quantifiable benefits of the proposed ESP. Mr. Malinak concludes that the ESP is more favorable than an MRO because DP&L SSO customers can expect to pay approximately $120 million less for default retail electric service through May 2018. Mr. Malinak also concludes that the faster transition to a competitive retail market provides non-quantifiable benefits such as a more attractive business climate in DP&L's service territory.

Q44. Have you identified any errors or shortcomings in the ESP versus MRO analysis performed by DP&L witness R. Jeffrey Malinak?

A44. Yes. The most significant flaw in Mr. Malinak's analysis is his assumption that the level of the non-bypassable charge collected through the SSR would be the same under an MRO as the proposed ESP. For the reasons discussed below, that assumption is not correct. Additionally, Mr. Malinak overlooks the projected impact of the ST in his analysis. When these flaws in Mr. Malinak's analysis are corrected, the ESP is less favorable than an MRO.

Q45. Why is Mr. Malinak's assumption regarding the level of SSR charge under an MRO incorrect?

A45. Mr. Malinak's assumption results in an increase in the legacy SSO price that would be blended with the results of a competitive bid under an MRO. DP&L currently collects a non-bypassable charge (the RSC) as part of its current ESP. The RSC collects approximately $73 million annually in revenues. DP&L's proposed SSR would increase the level of non-bypassable charges to collect $137.5 million annually.

It is my understanding that the law allows the Commission to adjust the legacy SSO price to be blended under an MRO in certain limited circumstances. As previously noted, those circumstances only contemplate adjusting the legacy SSO price to reflect any of the circumstances described below:

- changes in the EDU's prudently incurred costs of fuel used to produce electricity; or
- changes in the EDU's purchased power costs; or
- changes in the EDU's costs to comply with energy efficiency, peak demand reduction and renewable portfolio requirements; or
- changes in the EDU's costs to comply with environmental laws and regulations.

None of those circumstances is applicable to DP&L's proposed SSR. Additionally, it is my understanding that the Commission may adjust the legacy SSO price to be blended under an MRO if necessary to address an EDU's financial emergency, or to prevent a taking of property without compensation pursuant to Section 19 of Article I, Ohio Constitution. As discussed in the direct testimony of IEU-Ohio witness Joseph G. Bowser, DP&L has not provided the necessary information to demonstrate its financial integrity is threatened.

Because none of the circumstances to adjust the legacy SSO price exists, Mr. Malinak's assumed increase in the SSO price that would be blended with the results of a CBP is incorrect. In fact, as discussed below, Mr. Malinak's assumption is inconsistent with positions DP&L itself has argued in this proceeding. It is also inconsistent with an initial determination of the Commission on DP&L's current RSC.

As the Commission is aware, in this proceeding a dispute has arisen between the parties regarding whether continuation of DP&L's current ESP permits continued collection of the RSC after December 31, 2012. As a result of that dispute, several parties (including IEU-Ohio) filed a motion on September 26, 2012 requesting that the Commission enforce the stipulation and recommendation approved by the Commission in Case No. 08-1094-EL-SSO, establishing DP&L's current ESP. The parties argued that the stipulation, by its terms, required the RSC to terminate on December 31, 2012.

DP&L filed a memorandum contra to the September 26, 2012 motion. In its memorandum contra, DP&L argued that continuation of DP&L's current ESP after December 31, 2012 required maintaining current ESP rates, including the RSC at the current level of $73 million in annual revenues. Thus, contrary to Mr. Malinak's assumptions, DP&L agreed that the current ESP would not allow DP&L to collect $137.5 million in non-bypassable charges and instead required continuation of the RSC at present levels.

On December 19, 2012, the Commission issued an entry addressing the September 26, 2012 motion and DP&L's response. In the entry, the Commission determined that continuation of the current ESP after December 31, 2012 was appropriate and that the provisions, terms and conditions of the current ESP include the current RSC.[6] Those are the rates that would be blended with the results of a CBP under an MRO. Therefore, Mr. Malinak's assumed higher level of non-bypassable charges in his ESP versus MRO analysis is at odds with the Commission's December 19, 2012 entry.

Q46. Did you perform an ESP versus MRO analysis?

A46. Yes.

Q47. What assumptions did you make for the purpose of performing your ESP versus MRO analysis?

[6] Some parties have sought rehearing of the Commission's December 19, 2012 entry and those requests for rehearing remain pending before the Commission.

A47. I adopted the assumed CBP results that were utilized by Mr. Malinak in his ESP versus MRO analysis. These estimated CBP results were developed by DP&L witness Teresa F. Marrinan, with adjustments by DP&L witness Emily W. Raab. I also assumed the starting date for the ESP as June 1, 2013. I selected this starting date because DP&L has indicated it will proceed as soon as practical with the first CBP after receiving a Commission order approving the ESP. Based upon my understanding of the procedural schedule in this case, even June 1, 2013 may be an overly-optimistic estimate of when the results of a CBP can be implemented. It is clear the results of a CBP did not go into effect on January 1, 2013.

I then performed an ESP versus MRO analysis under four scenarios.

Q48. What are the results of your ESP versus MRO analysis?

A48. The first scenario, which is shown on Exhibit KMM-14, reflects the current level of RSC charges continuing as part of the legacy ESP price that is blended with the results of a CBP under an MRO. Conversely, the ESP reflects DP&L's proposal to collect $137.5 million annually through the non-bypassable SSR.

In his testimony, Mr. Malinak concludes that the ESP is more favorable than an MRO and benefits SSO customers by approximately $120 million over the term of the ESP. However, as previously noted, this is based upon the false premise that the SSR collecting $137.5 million each year would exist under an MRO. DP&L's proposal results in a significant increase ($64.5 million) in the level of non-bypassable revenues being collected from customers each year. When this increase is properly reflected in the ESP versus MRO analysis, as shown on Exhibit KMM-14, it demonstrates the ESP is $204 million less favorable than an MRO over the term of the ESP. In other words, the incremental increase in non-bypassable charges over the term of the ESP, which totals $324 million, eclipses Mr. Malinak's estimated ESP price savings of $120 million.

My second scenario is identical to the first scenario with one difference. In the second scenario, I modeled the projected impacts associated with DP&L's proposed ST at an assumed switching rate of 70% to be conservative. The results of this scenario are shown on Exhibit KMM-15. With just this slight increase in assumed switching, the ESP is less favorable than an MRO by $305 million over the term of the ESP.

In the third scenario, which is shown on Exhibit KMM-16, I assumed, consistent with the positions advocated by IEU-Ohio and other parties to this proceeding that the existing RSC charge was required to terminate on December 31, 2012. After making this assumption, the ESP is less favorable than an MRO by $568 million over the term of the ESP.

The fourth scenario is identical to the third scenario but models the projected impacts associated with DP&L's proposed ST at an assumed switching rate of 70% to be conservative. The results are shown on Exhibit KMM-17. With assumed higher levels of switching, the proposed ESP is less favorable than an MRO by $668 million over the term of the ESP.

Q49. Do you agree with Mr. Malinak's conclusion that the ESP provides other non-quantifiable benefits?

A49. No. Mr. Malinak reasons that a faster transition to prices entirely set through a CBP is beneficial and that it will create a more favorable business climate in DP&L's service territory. The reality is the vast majority of DP&L's business customers are already shopping. As of the end of the third quarter 2012, which is the most recent report available, the Commission's electric switching report which is attached to my testimony as Exhibit KMM-15, shows that 94.31% of DP&L industrial sales are being supplied through CRES providers and 75.54% of DP&L commercial sales are being supplied through CRES providers. For these customers, DP&L's proposed ESP will result in a significant increase in their overall price of electricity. It is axiomatic that an ESP that results in higher electricity prices for the vast majority of commercial and industrial customers cannot be properly characterized as creating a more favorable business climate.

VI. TRANSMISSION COST RECOVERY RIDER

Q50. How does DP&L presently recover transmission and ancillary services costs from customers?

A50. DP&L presently has a Transmission Cost Recovery Rider ("TCRR") that is designed to cover all transmission and transmission-related costs or credits, including ancillary and congestion costs, imposed on or charged to DP&L by FERC or PJM. The TCRR is fully avoidable by shopping customers. Shopping customers pay for transmission and ancillary services costs to PJM through their

CRES provider, who obtains transmission and ancillary services on behalf of the customer through PJM. The transmission revenue collected by PJM from CRES providers serving customers within DP&L's service area is then remitted to DP&L. PJM also remits revenue to DP&L for any ancillary services provided by DP&L.

Q51. Has DP&L proposed any changes to its TCRR?

A51. Yes. DP&L has proposed to split the TCRR into two separate riders. The first rider, TCRR-N, will recover the costs associated with network integration transmission service, regional transmission expansion plans and other FERC or PJM charges that are non-market-based. The second rider, TCRR-B, will recover other remaining costs currently collected through Rider TCRR associated with ancillary services and other market-based charges. DP&L has proposed that Rider TCRR-B remain fully avoidable for shopping customers. However, DP&L has requested a waiver of Rule 4901:1-36-04(B), Ohio Administrative Code, that requires that a transmission cost recovery rider be avoidable by shopping customers. DP&L has requested the Commission approve Rider TCRR-N as a non-bypassable charge.

Q52. Why did DP&L propose Rider TCRR-N?

A52. According to the testimony of DP&L witness Claire E. Hale, DP&L believes that removing the non-market-based charges to be collected through Rider TCRR-N from the product that potential suppliers will be requested to provide through the CBP to secure generation supply for SSO customers is appropriate. Ms. Hale believes this will lower the generation price that bidders offer and will result in less variation in the price to compare.

Q53. Are DP&L's proposed changes to Rider TCRR appropriate?

A53. No. DP&L's proposed changes to Rider TCRR would disrupt the contractual relationship between DP&L customers that are presently shopping (who constitute the majority of DP&L's customers) and their CRES providers. As previously noted, shopping customers presently pay for transmission and ancillary services to PJM through their CRES provider. Therefore, for customers on term contracts the price they pay their CRES provider includes compensation for non-market-based transmission and ancillary services. If the Commission approves DP&L's proposed Rider TCRR-N, shopping customers with term contracts could end up paying twice for non-market-based transmission and ancillary services.

Q54. What are your recommendations regarding Rider TCRR?

A54. The Commission should not adopt DP&L's proposed changes to Rider TCRR. Alternatively, if the Commission approves DP&L's proposal to create Rider TCRR-N and Rider TCRR-B, both riders should remain fully avoidable by shopping customers.

VII. CONCLUSION

Q55. Does this conclude your testimony?

A55. Yes.

<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that a copy of the foregoing *Direct Testimony of Kevin M. Murray on Behalf of Industrial Energy Users-Ohio* was served upon the following parties of record this 1st day of March 2013, *via* electronic transmission.

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Exhibit KMM-1

Exhibit KMM-1

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, PUCO Case No. 10-2929-EL-UNC.

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan, PUCO Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, *et al.*

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan, and the Sale or Transfer of Certain Generating Assets, Case No. 08-917-EL-SSO and *In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan*, PUCO Case No. 08-918-EL-SSO (remand phase).

In the Matter of the Application of Columbus Southern Power for Approval of its Program Portfolio Plan and Request for Expedited Consideration, PUCO Case No. 09-1089-EL-POR.

In the Matter of the Application of Ohio Power Company for Approval of its Program Portfolio Plan and Request for Expedited Consideration, PUCO Case No. 09-1090-EL-POR.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service, PUCO Case No. 09-906-EL-SSO.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, PUCO Case No. 08-935-EL-SSO.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service, PUCO Case No. 08-936-EL-SSO.

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets, PUCO Case Nos. 08-917-EL-SSO.

In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan, PUCO Case No. 08-918-EL-SSO.

In the Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan, PUCO Case No. 08-920-EL-SSO.

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan, PUCO Case No. 08-1094-EL-SSO.

Exhibit KMM-2

CONFIDENTIAL

Exhibit KMM-3

The AES Corporation

47th Annual EEI Financial Conference

November 2012

AES

we are the energy

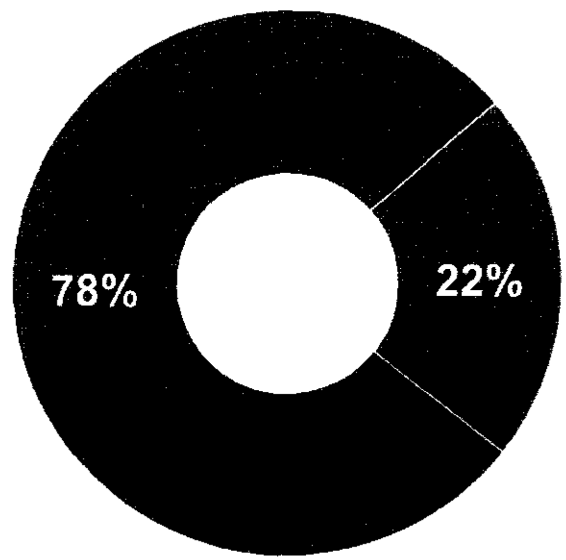
Safe Harbor Disclosure

Certain statements in the following presentation regarding AES' business operations may constitute "forward-looking statements." Such forward-looking statements include, but are not limited to, those related to future earnings growth and financial and operating performance. Forward-looking statements are not intended to be a guarantee of future results, but instead constitute AES' current expectations based on reasonable assumptions. Forecasted financial information is based on certain material assumptions. These assumptions include, but are not limited to accurate projections of future interest rates, commodity prices and foreign currency pricing, continued normal or better levels of operating performance and electricity demand at our distribution companies and operational performance at our generation businesses consistent with historical levels, as well as achievements of planned productivity improvements and incremental growth from investments at investment levels and rates of return consistent with prior experience. For additional assumptions see Slide 27 and the Appendix to this presentation. Actual results could differ materially from those projected in our forward-looking statements due to risks, uncertainties and other factors. Important factors that could affect actual results are discussed in AES' filings with the Securities and Exchange Commission including but not limited to the risks discussed under Item 1A "Risk Factors" and Item 7: Management's Discussion & Analysis in AES' 2011 Annual Report on Form 10-K, as well as our other SEC filings. AES undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Who We Are: A Diversified Power Generation & Distribution Company

Generation

- 37 Generation businesses
- 34 GW of generating capacity



Utilities

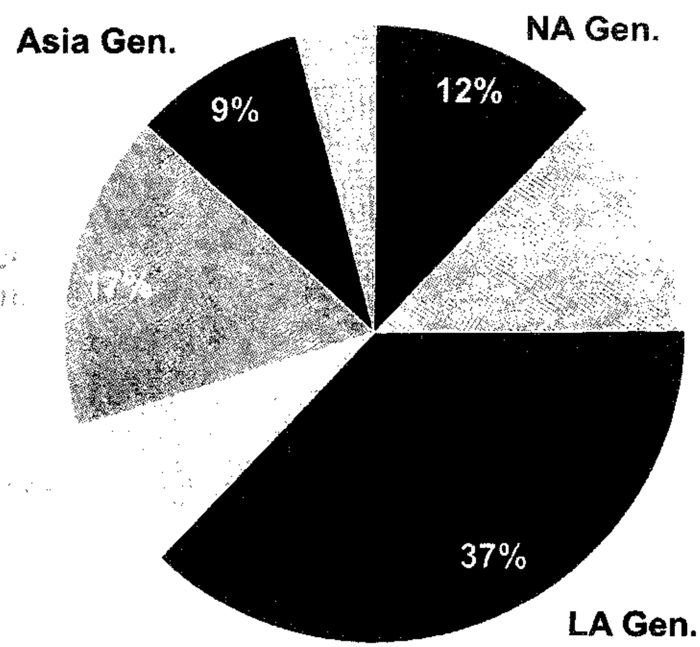
- 13 Utilities companies serving 12 million customers
- Operate 8 GW of generating capacity

Commodity and Currency Risks Limited by Contracts & Regulatory Structures, as well as Diversification Across Geographies, Asset & Fuel Types

1. A non-GAAP financial measure. See Appendix for definition and reconciliation.

Adjusted Pre-Tax Contribution (PTC)[1] by Segment

YTD Q3 2012: $1.5 Billion Before Corporate Charges of $0.5 Billion



Adjusted PTC[1] Before Corporate Charges	$1,543
Corporate Charges	($532)
Adjusted PTC[1] After Corporate Charges	**$1,011**
Adjusted EPS[1]	**$0.91**

Note: Adjusted EPS reflects a 31% tax rate and 763 million shares outstanding.

Generation Businesses Account for 78% of Adjusted PTC; Latin America is the Largest Region: 45%, Followed by North America: 25%

1.A non-GAAP financial measure. See Appendix for definition and reconciliation.

Plan to Unlock Shareholder Value

1. Optimize capital allocation	■ Invest cash to maximize total returns
2. Improve profitability	■ Cut costs and leverage footprint
3. Narrow our geographic focus	■ Exit non-strategic assets to simplify story ■ Grow in markets of choice where we have a competitive advantage

Focus on Delivering Attractive Risk-Adjusted Total Shareholder Return

Update on Plan to Unlock Shareholder Value: Optimize Capital Allocation

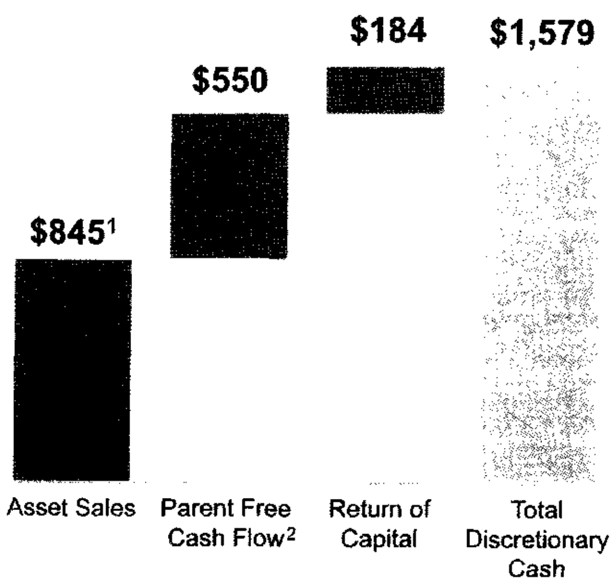
1. Debt repayment	■ $717 million in pre-payments ◆ $295 million Recourse debt (completed) ◆ $197 million Non-Recourse debt (Brasiliana)[1] (completed) ◆ AES Board approval to pre-pay $225 million Recourse debt
2. Share buyback	■ 34 million shares repurchased by investing $390 million (average price of $11.55/share) ◆ Since August 2012, bought back 4.3 million shares by investing $49 million (average price of $11.38/share)
3. Dividend	■ $0.04/share to be paid on November 15, 2012

Since September 2011, $1.1 Billion Invested in Our Balance Sheet

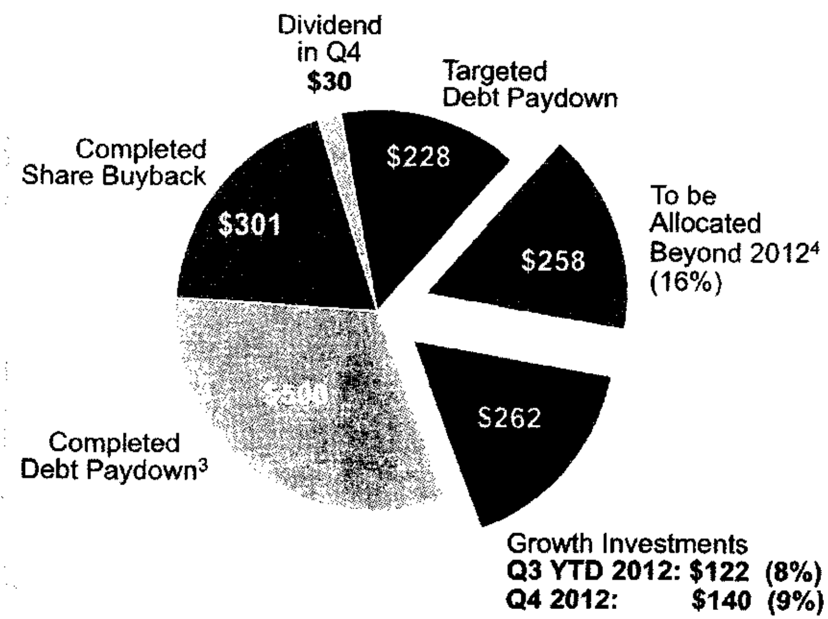
1. AES owns 46% of its Brasiliana subsidiary. Reflects AES' ownership percentage.

Update on Plan to Unlock Shareholder Value: Balanced Approach to Capital Allocation in 2012

$ in Millions



Return to Shareholders & Debt Paydown: 67%

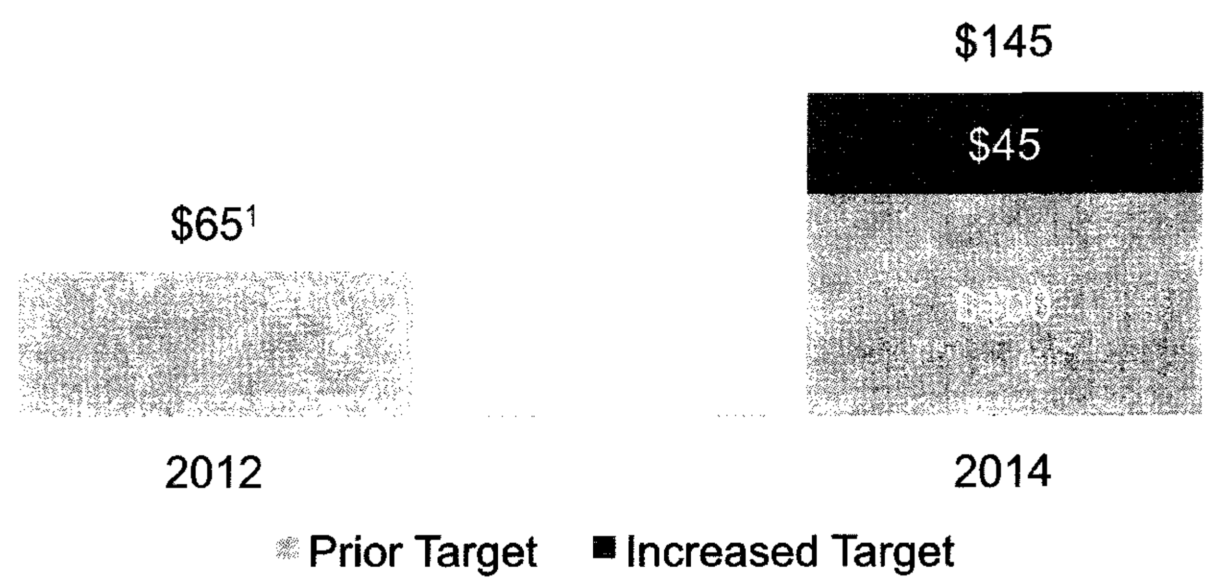


Unallocated Cash to Be Invested According to Capital Allocation Framework to Achieve Total Return Targets

1. Excludes $87 million dividend related to Atimus (Brazil Telecom), which is included in Parent Free Cash Flow.
2. Low end of 2012 parent free cash flow guidance range given on November 7, 2012. A non-GAAP financial measure. See Appendix for definition and reconciliation.
3. Completed $500 million debt paydown: $295 million corporate revolver, $8 million scheduled debt payment, and $197 million non-recourse debt.
4. To be allocated beyond 2012: $258 million will be used for investment in growth, stock buyback and/or debt repayment.

Update on Plan to Unlock Shareholder Value: Improve Profitability

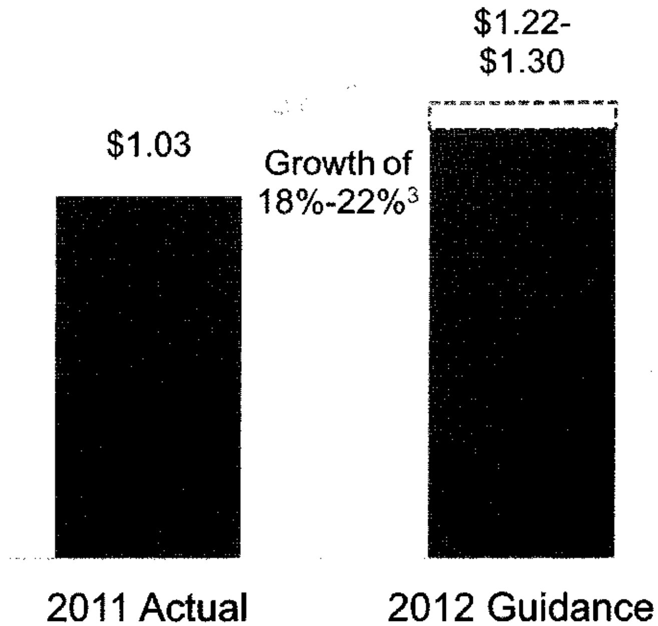
$ in Millions

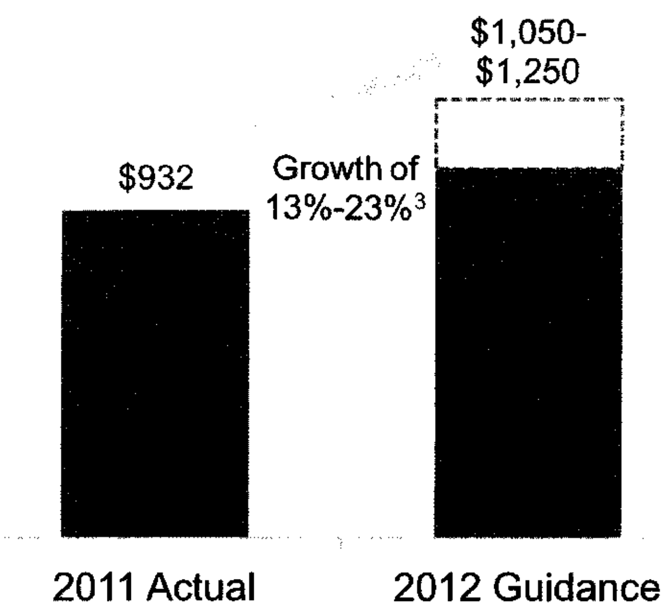


Projected 2012 Savings of $65 Million[1]; Cumulative Target of $145 Million in Annual Savings by End of 2014

1. Net of one-time restructuring expenses.

Delivering Results: Expect to Achieve Significant Growth in Adjusted EPS[1] & Proportional Free Cash Flow[1] in 2012





2012 Growth Largely Driven by Contributions from New Businesses Added in 2011

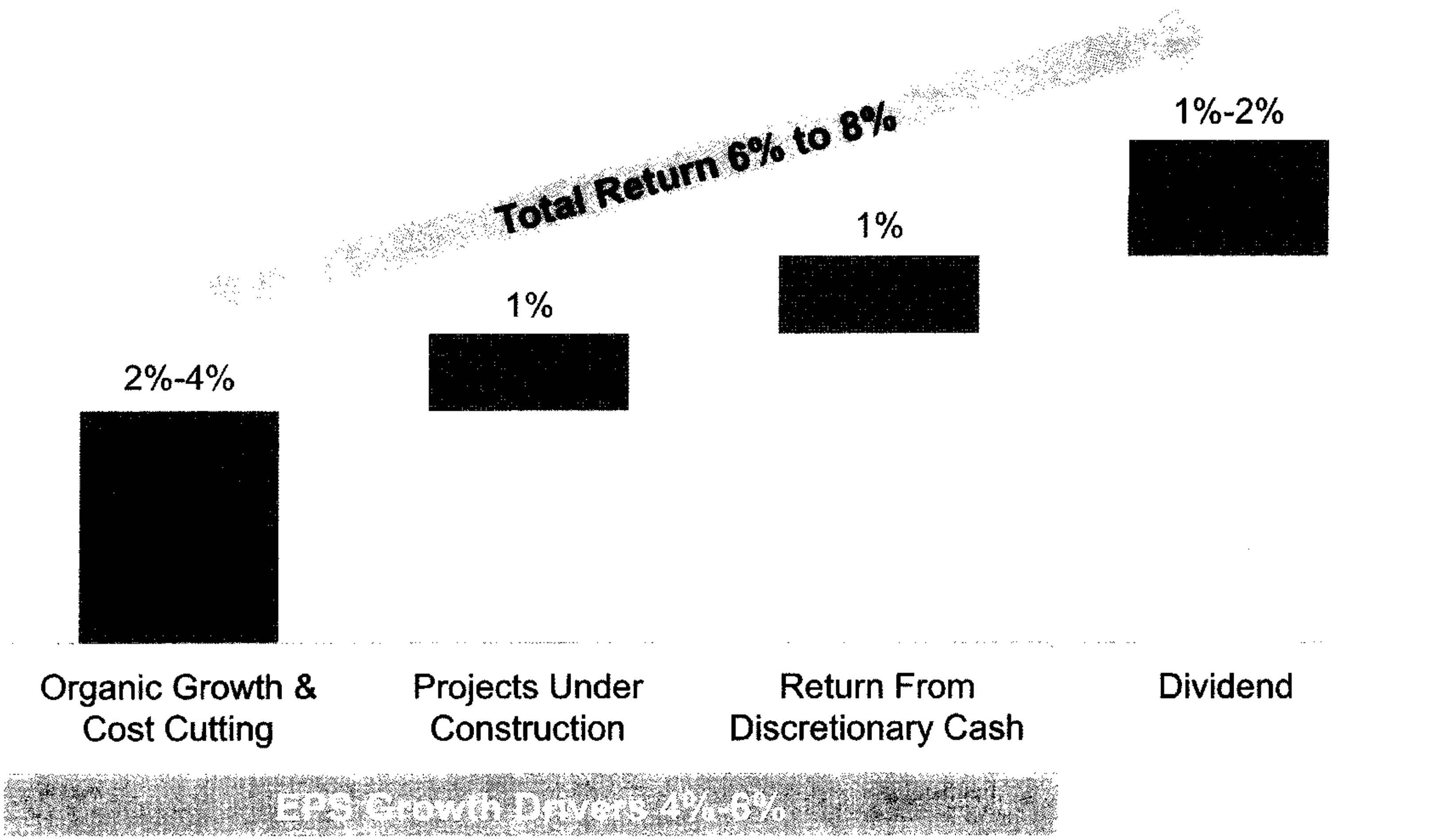
1. A non-GAAP financial measure. See Appendix for definition and reconciliation.
2. Diluted earnings per share from continuing operations was $0.59 in 2011.
3. Based on the lower end and midpoint of the guidance range.

Drivers of Modest Growth in 2013

+ Improved performance at AES Gener
+ Recovery at Eletropaulo in Brazil
+ Capital allocation (including share repurchases done in 2012)
+ Cost reductions (full year of 2012 reductions; partial year of incremental reductions in 2013)
– DPL (lower gas prices and cumulative impact of customer switching)
– Foreign exchange impacts

Plan to Provide 2013 Guidance on Q4 2012 Earnings Call (February 2013)

Forecasting Average Annual Total Return of 6% to 8% (2012-2015)[1]



1. Off 2012 base.

Key Investment Considerations

- Diversified power generation and distribution company
  - Faster demand growth in emerging markets combined with cash flow stability from developed markets
  - Commodity and currency risks mostly mitigated by contracts and regulatory structures
- Optimizing capital allocation and de-risking balance sheet
  - Repurchased $390 million of common stock since September 2011
  - Paid down or authorized pre-payment of a total of $717 million in debt
  - Limiting our growth commitments primarily to attractive platform expansion projects
- Improving profitability through targeted cost reductions and debt repayment
- Exiting non-strategic assets and markets to simplify the story
  - Reinvesting cash consistent with our capital allocation framework
- Delivering on our commitments for 2012
- Committed to delivering 6%-8% average annual total return in 2012-2015

Appendix

Update on DPL

- Performance has been adversely affected compared to our expectations at the time of acquisition – resulted in a goodwill impairment in the range of $1.7 to $2.0 billion
  - Lower margins due to:
    - Lower gas prices
    - Accelerated competition resulted in increased switching (as of September 2012, 63% of regulated load had switched)
- Our action plan
  - Achieve a reasonable outcome in the rate case negotiations
    - Filed an ESP October 5th
    - Expect final resolution by first quarter 2013
  - Expand retail customer base – retained 73% of the switched load
  - Balance sheet optimization – de-lever the business with cash generated at DPL

DPL Gas Price Sensitivity as of September 30, 2012

Expected Production (TWh)	15	14	13
Hedged %	75%-80%	~25%	<10%
NYMEX Natural Gas Futures Price @ 9/30/12 ($/MMbtu)	$3.84	$4.18	$4.37
PTC Impact +$1/MMbtu Change in Gas Price	+$15-$20 Million	+$60-$70 Million	+$75-$85 Million
PTC Impact -$1/MMbtu Change in Gas Price	-$3-$6 Million	-$45-$55 Million	-$65-$75 Million

Note: Sensitivities are provided on a standalone basis, assuming no change in the other factors, to illustrate the magnitude and direction of changing market factors on AES results. Estimates show the impact on 2012 adjusted PTC. Actual results may differ from the sensitivities provided due to execution of risk management strategies, local market dynamics and operational factors. 2012 guidance is based on currency and commodity forward curves and forecasts as of September 30, 2012. There are inherent uncertainties in the forecasting process and actual results may differ from projections. The Company undertakes no obligation to update the guidance presented today. Please see Item 3A of the Form 10-Q for a more complete discussion of this topic. AES has exposure to multiple coal, oil, and natural gas indices; forward curves are provided for representative liquid markets.

Regulatory Developments in Brazil

- On September 11th, in order to stimulate the economy and contain inflation, the Brazilian Government announced its plan (Provisional Measure 579) to lower average electricity tariffs by ~20% through:
  - Reduction in indirect taxes on the sector
  - Reduction through negotiations with transmission, generation and distribution businesses with concession agreements expiring in 2015-2017
- Impact on our Brazilian businesses should be minimal in the near-term
  - Our generation business, Tiete, has a concession expiring in 2029, outside of this regulation's scope
    - Tiete has a contract to supply power to Eletropaulo through December 2015
  - Our distribution businesses, Sul and Eletropaulo, are not affected due to pass-through provisions and hold concessions expiring in 2027 and 2028, respectively

Chile

- All plants are fully operational, including those that were offline in the second quarter for maintenance
- Reduced exposure to volatile spot market prices
  - 545 MW Angamos plant is now 90% hedged under a long-term contract, versus 65% in the first quarter
- Favorable trends in energy demand growth (4%-6% growth over the last three months)

Update on Plan to Unlock Shareholder Value: Narrow Geographic Focus

Atimus (Brazil Telecom)	$284[2]		Non-core asset; Paid down $197 million[2] in debt at Brasiliana subsidiary
Bohemia (Czech Republic)	$12		Completed exit from non-core Market
Edes and Edelap (Argentina)	$4		Underperforming business
Cartagena[1] (Spain)	$229	$884 closed	No expansion potential
Red Oak (U.S.)	$142		No expansion potential
Ironwood (U.S.)	$85		
French Wind (France)	$42		Non-core market
Yangcheng & China Wind (China)	$86		Non-core market
JHRH (China)	$49 signed		Non-core market; expected to close late 2012
Total	**$933**		

Businesses Sold at a P/E Multiple of More Than 20x 2011 Adjusted Earnings[3]

1. Sold 80% of our interest to GDF Suez in February 2012. GDF Suez has the option to buy the remaining 20% interest in 2013.
2. AES owns 46% of its Brasiliana subsidiary. Proceeds and debt reflect AES' ownership percentage.
3. Excludes China asset sales, as these businesses reported $9 million in losses in 2011.

Key Assumptions for 2012 Guidance[1]

- Foreign currency and commodity assumptions from the forward curve as of September 30, 2012
- Tax rate on adjusted earnings in low 30% range, which includes anticipated extension of CFC look-thru benefits
- Includes the impacts of announced and closed asset sales through September 30, 2012
- Allocation of discretionary cash consistent with Slide 7

1. Guidance given November 7, 2012.

2012 Guidance Estimated Sensitivities

100 bps move in interest rates over a 12-month period is equal to change in EPS of approximately $0.025

10% appreciation in USD against the following key currencies is equal to the following negative EPS impacts:

Brazilian Real (BRL)	2.03	$0.005
Argentine Peso (ARS)	4.82	Immaterial
Euro (EUR)	1.29	Immaterial
Philippine Peso (PHP)	41.8	Immaterial

Newcastle Coal (Sensitivity $10/ton)	$89/ton	Less Than $0.005, negative correlation
NYMEX Coal (Sensitivity $10/ton)	$54/ton	
IPE Brent Crude Oil (Sensitivity $10/barrel)	$114/bbl	$0.005, positive correlation
NYMEX WTI Crude Oil (Sensitivity $10/barrel)	$92/bbl	
Henry Hub Natural Gas (Sensitivity $1/mmbtu)	$3.3/mmbtu	$0.005, positive correlation
UK National Balancing Point Gas (Sensitivity $1/mmbtu)	£0.62/therm	

Note: Guidance given November 7, 2012. Sensitivities are provided on a standalone basis, assuming no change in the other factors, to illustrate the magnitude and direction of changing market factors on AES results. Estimates show the impact on 2012 adjusted EPS. Actual results may differ from the sensitivities provided due to execution of risk management strategies, local market dynamics and operational factors. 2012 guidance is based on currency and commodity forward curves and forecasts as of September 30, 2012. There are inherent uncertainties in the forecasting process and actual results may differ from projections. The Company undertakes no obligation to update the guidance presented today. Please see Item 3A of the Form 10-Q for a more complete discussion of this topic. AES has exposure to multiple coal, oil, and natural gas indices; forward curves are provided for representative liquid markets. Sensitivities are rounded to the nearest ½ cent per share.

1.The move is applied to the floating interest rate portfolio balances as of September 30, 2012.

Reconciliation of Adjusted PTC[1] & Adjusted EPS[1]

$ in Millions, Except Per Share Amounts

Income from Continuing Operations Attributable to AES & Diluted EPS	**($1,155)**		**($1.51)**
Add Back Income Tax from Continuing Operations Attributable to AES	$330		
Pre-Tax Contribution	($825)		
Unrealized Derivatives Losses	$84	$55	$0.07
Unrealized Foreign Currency Transaction (Gains)	($10)	($4)	($0.01)
Disposition/Acquisition (Gains)	($206)	($138)	($0.18)
Impairment Losses	$1,968	$1,937	$2.54
Debt Retirement Losses	-	-	-
Adjusted PTC[1] & Adjusted EPS[1]	**$1,011**		**$0.91**

1. A non-GAAP financial measure. See "definitions".
2. See description of adjustments on Slide 22.

Reconciliation of Adjusted Earnings Per Share[1]

Diluted EPS from Continuing Operations	**($2.09)**	**($0.09)**	**($1.51)**	**$0.46**
Unrealized Derivative Losses[2]	-	$0.01	$0.07	-
Unrealized Foreign Currency Transaction (Gains)/ Losses[3]	($0.01)	$0.08	($0.01)	$0.03
Disposition/Acquisition (Gains)	($0.04)[4]	-	($0.18)[5]	-
Impairment Losses	$2.50[6]	$0.25[7]	$2.54[8]	$0.28[9]
Debt Retirement Losses	-	$0.03[10]	-	$0.04[11]
Adjusted EPS[1]	**$0.36**	**$0.28**	**$0.91**	**$0.81**

1. A non-GAAP financial measure as reconciled above. See "definitions."
2. Unrealized derivative losses were net of income tax per share of $0.01 and $0.01 in the three months ended September 30, 2012 and 2011 respectively, and $0.04 and $0.01 in the *nine months ended September 30, 2012 and 2011, respectively.*
3. Unrealized foreign currency transaction (gains)/losses were net of income tax per share of ($0.01) and $0.03 in the three months ended September 30, 2012 and 2011, respectively, and of ($0.01) and $0.00 in the nine months ended September 30, 2012 and 2011, respectively.
4. Amount primarily relates to the gain from the sale of our interest in China of $24 million ($28 million, or $0.04 per share including an income tax credit of $4 million, or $0.00 per share).
5. Amount primarily relates to the gain from the sale of 80% of our interest in Cartagena for $178 million ($106 million or $0.14 per share, net of income tax of $0.09 per share) and China of $24 million ($28 million, or $0.04 per share including an income tax credit of $4 million, or $0.00 per share).
6. Amount primarily relates to the goodwill impairment at DPL of $1.85 billion ($1.85 billion, or $2.46 per share, net of income tax of $0.00 per share), asset impairments of Wind turbines and projects of $36 million ($26 million, or $0.03 per share, net of income tax of $0.01 per share) and at Kelanitissa of $5 million ($3 million or $0.00 per share, net of non-controlling interest and of income tax of $0.00 per share).
7. Amount includes equity method investment impairment at Chigen, including Yangcheng, of $79 million ($78 million or $0.10 per share, net of income tax of $0.00 per share), asset impairments at Wind of $116 million ($86 million, or $0.11 per share, net of income tax of $0.04 per share), Kelanitissa of $4 million ($4 million or $0.01 per share, net of non-controlling *interest), and Bohemia of $9 million ($11 million, and* $0.01 per share including an income tax credit of $2 million or $0.00 per share), and goodwill impairment at Chigen of $17 million ($13 million or $0.02 per share, net of income tax of $0.01 per share).
8. Amount primarily relates to the goodwill impairment at DPL of $1.85 billion ($1.85 billion, or $2.42 per share, net of income tax of $0.00 per share). Amount also includes other-than-temporary impairment of equity method investments in China of $32 million ($26 million or $0.03 per share, net of income tax of $0.01 per share), and at InnoVent of $17 million ($12 million, or $0.02 per share, *net of income tax of $0.01 per share), as well as asset impairments of Wind turbines and projects* of $40 million ($28 million, or $0.04 per share, net of income tax of $0.02 per share), at Kelanitissa of $17 million ($11 million or $0.01 per share, net of non-controlling interest and income tax of $0.01 per share), and at St. Patrick of $11 million ($8 million, and $0.01 per share, net of income tax of $0.00 per share).
9. Amount includes equity method investment impairment at Chigen, including Yangcheng, of $79 million ($78 million or $0.10 per share, net of income tax of $0.00 per share), asset impairments at Wind of $116 million ($86 million, or $0.11 per share, net of income tax of $0.04 per share), Kelanitissa of $37 *million ($34 million or $0.04 per share, net of non-*controlling interest), and Bohemia of $9 million ($11 million, and $0.01 per share including an income tax credit of $2 million or $0.00 per share), and goodwill impairment at Chigen of $17 million ($13 million or $0.02 per share, net of income tax of $0.01 per share).
10. Amount includes loss on retirement of debt at Gener of $38 million ($20 million, or $0.03 per share, net of non-controlling interest and income tax per share of $0.01).
11. Amount includes loss on retirement of debt at IPL of $15 million ($11 million, or $0.01 per share, net of income tax per share of $0.01) and at Gener of $38 million ($20 *million*, or $0.03 per share, net of non-controlling interest and income tax per share of $0.01).

Reconciliation of 2012 Guidance, Including Proportional Metrics

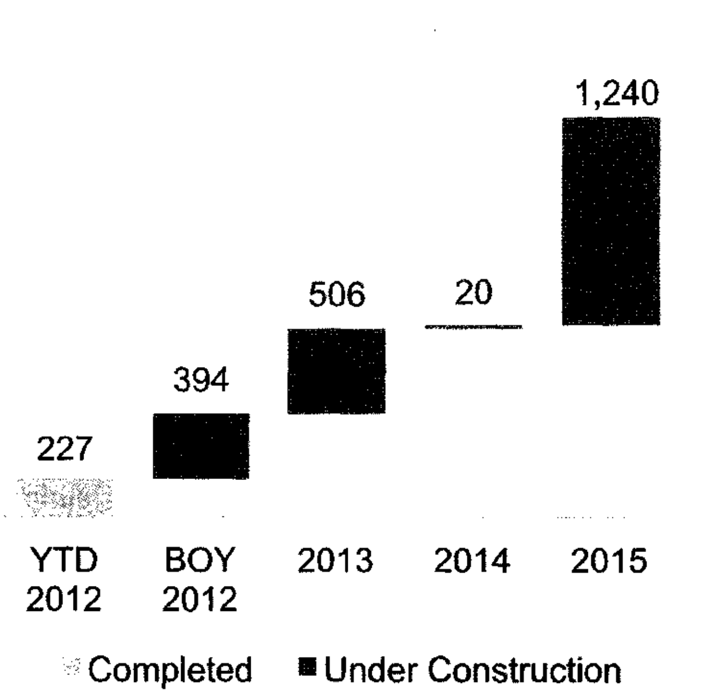
Income Statement Elements			
Adjusted Earnings Per Share[2]	$1.22-$1.30		
Cash Flow Elements			
Net Cash from Operating Activities	$2,900-$3,100	$975	$1,925-2,125
Operational Capital Expenditures (a)	$1,050-$1,125	$300	$725-$850
Environmental Capital Expenditures (b)	$100-$125	$25	$75-$100
Maintenance Capital Expenditures (a + b)	$1,150-$1,250	$325	$800-$950
Free Cash Flow[2]	$1,700-$1,900	$650	$1,050-$1,250
Subsidiary Distributions[3]	$1,325-$1,525		
Reconciliation of Parent Free Cash Flow			
Subsidiary Distributions[3] (c)	$1,325-$1,525		
Cash Interest (d)	$450-$500		
Cash for Development, General & Administrative and Tax (e)	$325-$375		
Parent Free Cash Flow (c – d – e)	$550-$650		
Reconciliation of Free Cash Flow[2]			
Net Cash from Operating Activities	$2,900-$3,100	$975	$1,925-$2,125
Less: Maintenance Capital Expenditures	$1,150-$1,250	$325	$800-$950
Free Cash Flow[2]	$1,700-$1,900	$650	$1,050-$1,250
Reconciliation of Adjusted Gross Margin[2]			
Gross Margin	$3,600-$3,800	$950	$2,650-$2,850
Plus: Depreciation & Amortization	$1,400-$1,500	$350	$1,050-$1,150
Less: General & Administrative	$300-$350	-	$300-$350
Adjusted Gross Margin[2]	$4,725-$4,925	$1,300	$3,425-$3,625
Reconciliation of Adjusted Pre-Tax Contribution[2]			
Adjusted Pre-Tax Contribution[2] Before Corporate Charges	$1,900-$2,100		
Less: Corporate Charges	$650-$750		
Adjusted Pre-Tax Contribution[2] After Corporate Charges	$1,250-$1,350		

Note: In providing its full year 2012 Adjusted EPS guidance, the Company notes that there could be differences between expected reported earnings and estimated operating earnings for matters such as, but not limited to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) gains or losses due to dispositions and acquisitions of business interests, (d) losses due to impairments, and (e) costs due to the early retirement of debt. At this time, AES management is not able to estimate the aggregate impact, if any, of these items on reported earnings. Accordingly, the company is not able to provide a corresponding GAAP equivalent for its Adjusted EPS guidance.

1. 2012 guidance is based on expectations for future foreign exchange rates and commodity prices as of September 30, 2012.
2. A non-GAAP financial measure as reconciled above. See "definitions."
3. See "definitions."

Construction Program Contributes Near-Term Growth

Long-Term Debt is Committed and AES has Funded its Equity Contributions



- 2012 additions include:
  - 394 MW Trinidad Unit 2, of which AES owns 10%
  - 227 MW renewable projects
- 2013 additions include:
  - 270 MW Campiche (Chile)
  - 216 MW Kribi (Cameroon)
  - 20 MW Sixpenny Wood (UK)
- 2014 addition represents 20 MW Tunjita (Colombia)
- 2015 addition represents 1,240 MW Mong Duong II (Vietnam)

1. As of November 5, 2012; 1,189 proportional MW. See Slide 25 for details of projects *under construction*.

Note: The totals represent projections and there can be no assurance that we will complete construction of these projects or that completion will occur in the timeframes set forth above. For discussion of risks involved in the development process, see Item 1-A: Risk Factors – *Our business is subject to substantial development uncertainties* in our 2011 Form 10-K.

2,160 MW Under Construction as of November 5, 2012

					Generation (Renewables)	
					UK	Colombia
Project	Trinidad Unit 2	Campiche	Kribi	Mong Duong II	Sixpenny Wood	Tunjita
% Owned	10%	71%	56%	51%	100%	71%
Type	Gas	Coal	Gas	Coal	Wind	Hydro
Gross MW	394 MW	270 MW	216 MW	1,240 MW	20 MW	20 MW
Expected Commercial Operations Date	Q4 2012	1H 2013	2013	2H 2015	2013	2014

Note: These are some of our construction projects. Other projects not currently on this slide, whether developed through acquisitions or otherwise, may be brought on-line before these projects. In addition, some of these examples may not close or be completed as anticipated, or they may be delayed, due to uncertainty inherent in the development process.

Contains Forward Looking Statements

Platform Expansion Examples: Strong Near-Term Growth Pipeline in Chile (AES Gener) and the United States (IPL)

- Adjacent to Angamos facility; plant site owned by Angamos
- Includes 20 MW battery storage facility (BESS)
- Construction contract and long-term power sales agreements in place
- Construction expected to begin in 2013

531 MW Run-of-River Hydro Alto Maipo (Chile)

- 50 km East of Santiago
- Environmental, water and civil works permits obtained
- Executed principal construction contracts
- Construction expected to begin in 2013

Upgrading 2,500 MW Coal-Fired Capacity at IPL (U.S.-Indiana)

- Installing pollution controls to comply with Mercury and Air Toxic Standards (MATS)
  - Investment will yield regulated returns
  - Will cover the required investment to upgrade 100% of IPL's base-load coal-fired capacity

Note: For discussion of risks involved in the development process, see Item 1-A: Risk Factors – Our business is subject to substantial development uncertainties in our 2011 Form 10-K.

Assumptions

Forecasted financial information is based on certain material assumptions. Such assumptions include, but are not limited to: (a) no unforeseen external events such as wars, depressions, or economic or political disruptions occur; (b) businesses continue to operate in a manner consistent with or better than prior operating performance, including achievement of planned productivity improvements including benefits of global sourcing, and in accordance with the provisions of their relevant contracts or concessions; (c) new business opportunities are available to AES in sufficient quantity to achieve its growth objectives; (d) no material disruptions or discontinuities occur in the Gross Domestic Product (GDP), foreign exchange rates, inflation or interest rates during the forecast period; and (e) material business-specific risks as described in the Company's SEC filings do not occur individually or cumulatively. In addition, benefits from global sourcing include avoided costs, reduction in capital project costs versus budgetary estimates, and projected savings based on assumed spend volume which may or may not actually be achieved. Also, improvement in certain KPIs such as equivalent forced outage rate and commercial availability may not improve financial performance at all facilities based on commercial terms and conditions. These benefits will not be fully reflected in the Company' s consolidated financial results.

The cash held at qualified holding companies ("QHCs") represents cash sent to subsidiaries of the Company domiciled outside of the U.S. Such subsidiaries had no contractual restrictions on their ability to send cash to AES, the Parent Company, however, cash held at qualified holding companies does not reflect the impact of any tax liabilities that may result from any such cash being repatriated to the Parent Company in the U.S. Cash at those subsidiaries was used for investment and related activities outside of the U.S. These investments included equity investments and loans to other foreign subsidiaries as well as development and general costs and expenses incurred outside the U.S. Since the cash held by these QHCs is available to the Parent, AES uses the combined measure of subsidiary distributions to Parent and QHCs as a useful measure of cash available to the Parent to meet its international liquidity needs. AES believes that unconsolidated parent company liquidity is important to the liquidity position of AES as a parent company because of the non-recourse nature of most of AES' indebtedness.

Definitions

Adjusted Earnings Per Share (a non-GAAP financial measure) is defined as diluted earnings per share from continuing operations excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) significant gains or losses due to dispositions and acquisitions of business interests, (d) significant losses due to impairments, and (e) costs due to the early retirement of debt. The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. AES believes that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose or acquire business interests or retire debt, which affect results in a given period or periods. Adjusted EPS should not be construed as an alternative to diluted earnings per share from continuing operations, which is determined in accordance with GAAP. For the three and nine months ended September 30, 2012, the Company refined its process for computing the tax effects of adjusted EPS items for interim periods. Accordingly, the Company has also reflected the refined process in the comparative three and nine months ended September 30, 2011.

Adjusted Gross Margin (a non-GAAP financial measure) is defined as gross margin plus depreciation and amortization less general and administrative expenses. AES believes adjusted gross margin is a useful measure for evaluating and comparing the operating performance of its businesses because it includes the direct operating costs of its business including overhead related expenses and excludes potential differences caused by variations in capital structures affecting interest income and expense, tax positions, such as the impact of changes in effective tax rates and the impact of depreciation and amortization expense.

Adjusted Pre-Tax Contribution (a non-GAAP financial measure) represents pre-tax income from continuing operations attributable to AES excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) significant gains or losses due to dispositions and acquisitions of business interests, (d) significant losses due to impairments, and (e) costs due to the early retirement of debt. It includes net equity in earnings of affiliates, on an after-tax basis. The GAAP measure most comparable to Adjusted PTC is income from continuing operations attributable to AES. AES believes that Adjusted PTC better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose or acquire business interests or retire debt, which affect results in a given period or periods. Earnings before tax represents the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the effects of tax planning, corresponding to the various jurisdictions in which the Company operates. Adjusted PTC should not be construed as an alternative to income from continuing operations attributable to AES, which is determined in accordance with GAAP.

Free Cash Flow (a *non-GAAP financial measure*) *is defined as net cash from operating activities less maintenance capital expenditures* (including environmental capital expenditures), net of reinsurance proceeds from third parties. AES believes that free cash flow is a useful measure for evaluating our financial condition because it represents the amount of cash provided by operations less maintenance capital expenditures as defined by our businesses, that may be available for investing or for repaying debt. Free cash flow should not be construed as an alternative to net cash from operating activities, which is determined in accordance with GAAP.

Net Debt (a non-GAAP financial measure) is defined as current and non-current recourse and non-recourse debt less cash and cash equivalents, restricted cash, short term investments, debt service reserves and other deposits. AES believes that net debt is a useful measure for evaluating our financial condition because it is a standard industry measure that provides an alternate view of a company's indebtedness by considering the capacity of cash. It is also a required component of valuation techniques used by management and the investment community.

Parent Company Liquidity (a *non-GAAP financial measure*) *is defined as cash at the Parent Company plus availability under corporate credit facilities plus* cash at qualified holding companies ("QHCs"). AES believes that unconsolidated Parent Company liquidity is important to the liquidity position of AES as a Parent Company because of the non-recourse nature of most of AES' indebtedness.

Parent Free Cash Flow (a non-GAAP financial measure) should not be construed as an alternative to Net Cash Provided by Operating Activities which is determined in accordance with GAAP. Parent Free Cash Flow is equal to Subsidiary Distributions less cash used for interest costs, development, general and administrative activities, and tax payments by the Parent Company. Parent Free Cash Flow is used for dividends, share repurchases, growth investments, recourse debt repayments, and other uses by the Parent Company.

Definitions, Cont'd.

Proportional Metrics – The Company is a holding company that derives its income and cash flows from the activities of its subsidiaries, some of which are not wholly-owned by the Company. Accordingly, the Company has presented certain financial metrics which are defined as Proportional (a non-GAAP financial measure) to account for the Company' s ownership interest.

Proportional metrics present the Company' s estimate of its share in the economics of the underlying metric. The Company believes that the Proportional metrics are useful to investors because they exclude the economic share in the metric presented that is held by non-AES shareholders. For example, Operating Cash Flow is a GAAP metric which presents the Company' s cash flow from operations on a consolidated basis, including operating cash flow allocable to noncontrolling interests. Proportional Operating Cash Flow removes the share of operating cash flow allocable to noncontrolling interests and therefore may act as an aid in the valuation the Company.

Proportional metrics are reconciled to the nearest GAAP measure. Certain assumptions have been made to estimate our proportional financial measures. These assumptions include: (i) the Company' s economic interest has been calculated based on a blended rate for each consolidated business when such business represents multiple legal entities; (ii) the Company' s economic interest may differ from the percentage implied by the recorded net income or loss attributable to noncontrolling interests or dividends paid during a given period; (iii) the Company' s economic interest for entities accounted for using the hypothetical liquidation at book value method is 100%; (iv) individual operating performance of the Company' s equity method investments is not reflected and (v) inter-segment transactions are included as applicable for the metric presented.

Subsidiary Liquidity (a non-GAAP financial measure) is defined as cash and cash equivalents and bank lines of credit at various subsidiaries.

Subsidiary Distributions should not be construed as an alternative to Net Cash Provided by Operating Activities which is determined in accordance with GAAP. *Subsidiary Distributions are important to the Parent Company because the Parent Company is a holding company that does not derive any significant* direct revenues from its own activities but instead relies on its subsidiaries' business activities and the resultant distributions to fund the debt service, investment and other cash needs of the holding company. The reconciliation of the difference between the Subsidiary Distributions and Net Cash Provided by Operating Activities consists of cash generated from operating activities that is retained at the subsidiaries for a variety of reasons which are both discretionary and non-discretionary in nature. These factors include, but are not limited to, retention of cash to fund capital expenditures at the subsidiary, cash retention associated with non-recourse debt covenant restrictions and related debt service requirements at the subsidiaries, retention of cash related to sufficiency of local GAAP statutory retained earnings at the subsidiaries, retention of cash for working capital needs at the subsidiaries, and other similar timing differences between when the cash is generated at the subsidiaries and when it reaches the Parent Company and related holding companies.

Exhibit KMM-4

ESP INT 5-12: Identify any documents that describe or discuss the policies or procedures that are currently used to establish the transfer price associated with wholesale electricity sales from DP&L to DPLER?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L states that information responsive to this request can be found in the produced documents "Dayton Pwr-DPL Retail Transactions-Transfer Price-Confirms" and "DP&L-to-DPLER Transfer Price & Confirmation Flow Diagram."

WITNESS RESPONSIBLE: Aldyn Hoekstra.

ESP INT 5-13: What costs are reflected in the transfer price associated with wholesale electricity sales from DP&L to DPLER?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 4 (proprietary), 6 (calls for narrative answer), and 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L states that the costs reflected in the transfer price associated with wholesale electricity sales from DP&L to DPLER are the market-based supply costs associated with meeting the full supply requirements required by a CRES supplier to satisfy a retail customer's bypassable generation and transmission service.

WITNESS RESPONSIBLE: Aldyn Hoekstra.

ESP INT 5-14: Does DP&L have any policies or procedures that are currently used to establish the costs that are recognized in the transfer price associated with wholesale electricity sales from DP&L to DPLER?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L states: Yes.

WITNESS RESPONSIBLE: Aldyn Hoekstra.

ESP INT 5-15: Identify any documents that describe or discuss the policies or procedures that are currently used to establish the costs that are recognized in the transfer price associated with wholesale electricity sales from DP&L to DPLER?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L states that information responsive to this request can be found in the produced documents "Dayton Pwr-DPL Retail Transactions-Transfer Price-Confirms" and "DP&L-to-DPLER Transfer Price & Confirmation Flow Diagram."

WITNESS RESPONSIBLE: Aldyn Hoekstra.

Exhibit KMM-5

339. Referring to page 50 of DP&L's 2011 Form 10-K, it states that "during 2010, we implemented a new wholesale agreement between DP&L and DPLER. Under this agreement, intercompany sales from DP&L to DPLER were based on the market prices for wholesale power. In periods prior to 2010, DPLER's purchases from DP&L were transacted at prices that approximated DPLER's sales prices to its end-use retail customers."

A. When was the new wholesale agreement between DP&L and DPLER implemented?

RESPONSE: General Objections Nos. 1 (relevance), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L states that the subject agreement was effective as of January 1, 2010.

B. Why was the contract methodology of making sales to DPLER at prices that approximated DPLER's sales prices to its end-use retail customers changed to making sales to DPLER based on the market prices for wholesale power?

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 4 (proprietary), 6 (calls for narrative answer), and 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L states that the change was made because it met DP&L's and DPLER's business needs.

C. How does DP&L determine the market price to charge DPLER for each transaction between DP&L and DPLER?

RESPONSE: General Objections Nos. 1 (relevance), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L states that it charges transfer prices for transactions between DP&L and DPLER based on wholesale market prices.

WITNESS RESPONSIBLE: Aldyn Hoekstra.

Exhibit KMM-6

CONFIDENTIAL

Exhibit KMM-7

CONFIDENTIAL

Exhibit KMM-8

CONFIDENTIAL

Exhibit KMM-9

CONFIDENTIAL

Exhibit KMM-10

CONFIDENTIAL

Exhibit KMM-11

CONFIDENTIAL

Exhibit KMM-12

CONFIDENTIAL

Exhibit KMM-13

INTERROGATORY NO. 9-10: Provide DP&L's historic ROEs for the years 2009, 2010, and 2011 for the generation, transmission, and distribution segments.

RESPONSE: General Objections Nos. 1 (relevance) and 2 (unduly burdensome). Subject to all general objections, DP&L states that the ROEs for the segments identified are not available.

WITNESS RESPONSIBLE: Craig Jackson.

INTERROGATORY NO. 9-11: Provide DP&L's projected ROEs for each year of the proposed ESP for the generation, transmission, and distribution segments.

RESPONSE: General Objections Nos. 1 (relevance) and 2 (unduly burdensome). Subject to all general objections, DP&L states that the projected ROEs for each year of the proposed ESP are not available.

WITNESS RESPONSIBLE: Craig Jackson.

Exhibit KMM-14

Exhibit KMM-14

Line	MRO and ESP Rates and Revenues	6/2013-5/2014	6/2014-5/2015	6/2015-5/2016	6/2016-5/2017	6/2017-5/2018	Total or Average	Source or Calculation
1	Bypassable Current Generation Rates ($/MWh)							
2	Current Generation Rates	$76.62	$76.62	$76.62	$76.62	$76.62		Second Revised Exhibit RJM-1
3	Forecasted CBP Auction Rates	$44.86	$58.01	$61.70	$64.07	$65.75		Second Revised Exhibit RJM-1
4								
5	CBP Rate Blending Schedule (%)							
6	MRO	10.0%	20.0%	30.0%	40.0%	50.0%		Second Revised Exhibit RJM-1
7	ESP	10.0%	40.0%	70.0%	100.0%	100.0%		Second Revised Exhibit RJM-1
8								
9	Blended SSO Rate ($/MWh)							
10	MRO	$73.44	$72.90	$72.14	$71.60	$71.19		Line 2*(1-Line 6)+Line 3*Line 6
11	ESP	$73.44	$69.18	$66.18	$64.07	$65.75		Line 2*(1-Line 7)+Line 3*Line 7
12	Difference in Bypassable Rates	$0.00	-$3.72	-$5.97	-$7.53	-$5.44		Line 10 - Line 11
13								
14	Total Bypassable Revenues ($Millions)							
15	MRO	$388.80	$385.91	$381.92	$379.04	$376.84	$1,912.52	Line 10 * Line 32
16	ESP	$388.80	$366.21	$350.33	$339.18	$348.07	$1,792.59	Line 11 * Line 32
17	Difference in Bypassable Revenues	$0.00	-$19.70	-$31.59	-$39.86	-$28.77	-$119.93	Line 16 - Line 15
18								
19	Non-bypassable Revenues ($Millions)							
20	MRO	$72.68	$72.68	$72.68	$72.68	$72.68	$363.40	Direct Testimony of Kevin Murray
21	ESP	$137.50	$137.50	$137.50	$137.50	$137.50	$687.50	Second Revised Exhibit RJM-1
22	Difference in Non-bypassable Revenues	$64.82	$64.82	$64.82	$64.82	$64.82	$324.10	Line 21 - Line 20
23								
24	ESP Versus MRO Price Test ($Millions)							
25	Difference in Bypassable Revenues	$0.00	-$19.70	-$31.59	-$39.86	-$28.77	-$119.93	Line 17
26	Difference in Non-bypassable Revenues	$64.82	$64.82	$64.82	$64.82	$64.82	$324.10	Line 18
27	**Total Change in Revenues**	$64.82	$45.12	$33.23	$24.96	$36.05	$204.17	Line 25 + Line 26
28								
29	**Load and Switching Assumptions**							
30								
31	Switching	61.7%	61.7%	61.7%	61.7%	61.7%		(1 - Line 32)/Line 33
32	DP&L SSO Load (TWh)	5.29	5.29	5.29	5.29	5.29		Second Revised Exhibit RJM-1 w/ adjustment to first CBP
33	Total Load (TWh)	13.82	13.82	13.82	13.82	13.82		Second Revised Exhibit RJM-1 w/ adjustment to first CBP

Exhibit KMM-15

Exhibit KMM-15

Line	MRO and ESP Rates and Revenues	6/2013-5/2014	6/2014-5/2015	6/2015-5/2016	6/2016-5/2017	6/2017-5/2018	Total or Average	Source or Calculation
1	Bypassable Current Generation Rates ($/MWh)							
2	*Current Generation Rates*	$76.62	$76.62	$76.62	$76.62	$76.62		*Second Revised Exhibit RJM-1*
3	Forecasted CBP Auction Rates	$44.86	$58.01	$61.70	$64.07	$65.75		Second Revised Exhibit RJM-1
4								
5	CBP Rate Blending Schedule (%)							
6	MRO	10.0%	20.0%	30.0%	40.0%	50.0%		Second Revised Exhibit RJM-1
7	ESP	10.0%	40.0%	70.0%	100.0%	100.0%		Second Revised Exhibit RJM-1
8								
9	Blended SSO Rate ($/MWh)							
10	MRO	$73.44	$72.90	$72.14	$71.60	$71.19		*Line 2*(1-Line 6)+Line 3*Line 6*
11	ESP	$73.44	$69.18	$66.18	$64.07	$65.75		Line 2*(1-Line 7)+Line 3*Line 7
12	Difference in Bypassable Rates	$0.00	-$3.72	-$5.97	-$7.53	-$5.44		Line 10 - Line 11
13								
14	Total Bypassable Revenues ($Millions)							
15	MRO	$304.55	$302.29	$299.16	$296.91	$295.18	$1,498.09	Line 10 * Line 35
16	ESP	$304.55	$286.85	$274.41	$265.68	$272.65	$1,404.15	Line 11 * Line 35
17	Difference in Bypassable Revenues	$0.00	-$15.43	-$24.75	-$31.22	-$22.54	-$93.94	Line 16 - Line 15
18								
19	Non-bypassable Revenues ($Millions)							
20	MRO	$72.68	$72.68	$72.68	$72.68	$72.68	$363.40	Direct Testimony of Kevin Murray
21	ESP	$137.50	$137.50	$137.50	$137.50	$137.50	$687.50	Second Revised Exhibit RJM-1
22	Difference in Non-bypassable Revenues	$64.82	$64.82	$64.82	$64.82	$64.82	$324.10	Line 21 - Line 20
23								
24	ESP Versus MRO Price Test ($Millions)							
25	Difference in Bypassable Revenues	$0.00	-$15.43	-$24.75	-$31.22	-$22.54	-$93.94	Line 17
26	Difference in Non-bypassable Revenues	$64.82	$64.82	$64.82	$64.82	$64.82	$324.10	Line 18
	Forecast Switching Tracker Revenue Requirement ($ Millions)	$36.43	$21.35	$17.12	$0.00	$0.00	$74.90	*Line 40*
27	**Total Change in Revenues**	$101.25	$70.73	$57.19	$33.60	$42.28	$305.05	Line 25 + Line 26 + Line 27
28								
29	**Load and Switching Assumptions**							
30								
31	August 30, 2012 Switching	61.7%	61.7%	61.7%	61.7%	61.7%		(1 - Line 32)/Line 33
32	August 30, 2012 DP&L SSO Load (TWh)	5.29	5.29	5.29	5.29	5.29		Second Revised Exhibit RJM-1 w/ adjustment to first CBP
33	Total Load (TWh)	13.82	13.82	13.82	13.82	13.82		*Second Revised Exhibit RJM-1 w/ adjustment to first CBP*
	Forecast Switching	70.0%	70.0%	70.0%	70.0%	70.0%		
	Forecast SSO Load	4.15	4.15	4.15	4.15	4.15		(1-Line 37)* Line 36
	Forecast Switching Tracker Revenue Requirement ($ Millions)	$36.43	$21.35	$17.12			$74.90	(Line 36 - Line 39)*(Line 5-Line 6)

Exhibit KMM-16

Exhibit KMM-16

Line	MRO and ESP Rates and Revenues	6/2013-5/2014	6/2014-5/2015	6/2015-5/2016	6/2016-5/2017	6/2017-5/2018	Total or Average	Source or Calculation
1	Bypassable Current Generation Rates ($/MWh)							
2	Current Generation Rates	$76.62	$76.62	$76.62	$76.62	$76.62		Second Revised Exhibit RJM-1
3	Forecasted CBP Auction Rates	$44.86	$58.01	$61.70	$64.07	$65.75		Second Revised Exhibit RJM-1
4								
5	CBP Rate Blending Schedule (%)							
6	MRO	10.0%	20.0%	30.0%	40.0%	50.0%		Second Revised Exhibit RJM-1
7	ESP	10.0%	40.0%	70.0%	100.0%	100.0%		Second Revised Exhibit RJM-1
8								
9	Blended SSO Rate ($/MWh)							
10	MRO	$73.44	$72.90	$72.14	$71.60	$71.19		Line 2*(1-Line 6)+Line 3*Line 6
11	ESP	$73.44	$69.18	$66.18	$64.07	$65.75		Line 2*(1-Line 7)+Line 3*Line 7
12	Difference in Bypassable Rates	$0.00	-$3.72	-$5.97	-$7.53	-$5.44		Line 10 - Line 11
13								
14	Total Bypassable Revenues ($Millions)							
15	MRO	$388.80	$385.91	$381.92	$379.04	$376.84	$1,912.52	Line 10 * Line 32
16	ESP	$388.80	$366.21	$350.33	$339.18	$348.07	$1,792.59	Line 11 * Line 32
17	Difference in Bypassable Revenues	$0.00	-$19.70	-$31.59	-$39.86	-$28.77	-$119.93	Line 16 - Line 15
18								
19	Non-bypassable Revenues ($Millions)							
20	MRO	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	Direct Testimony of Kevin Murray
21	ESP	$137.50	$137.50	$137.50	$137.50	$137.50	$687.50	Second Revised Exhibit RJM-1
22	Difference in Non-bypassable Revenues	$137.50	$137.50	$137.50	$137.50	$137.50	$687.50	Line 21 - Line 20
23								
24	ESP Versus MRO Price Test ($Millions)							
25	Difference in Bypassable Revenues	$0.00	-$19.70	-$31.59	-$39.86	-$28.77	-$119.93	Line 17
26	Difference in Non-bypassable Revenues	$137.50	$137.50	$137.50	$137.50	$137.50	$687.50	Line 18
27	**Total Change in Revenues**	$137.50	$117.80	$105.91	$97.64	$108.73	$567.57	Line 25 + Line 26
28								
29	**Load and Switching Assumptions**							
30								
31	Switching	61.7%	61.7%	61.7%	61.7%	61.7%		(1 - Line 32)/Line 33
32	DP&L SSO Load (TWh)	5.29	5.29	5.29	5.29	5.29		Second Revised Exhibit RJM-1 w/ adjustment to first CBP
33	Total Load (TWh)	13.82	13.82	13.82	13.82	13.82		Second Revised Exhibit RJM-1 w/ adjustment to first CBP

Exhibit KMM-17

Exhibit KMM-17

Line	MRO and ESP Rates and Revenues	6/2013-5/2014	6/2014-5/2015	6/2015-5/2016	6/2016-5/2017	6/2017-5/2018	Total or Average	Source or Calculation
1	Bypassable Current Generation Rates ($/MWh)							
2	Current Generation Rates	$76.62	$76.62	$76.62	$76.62	$76.62		Second Revised Exhibit RJM-1
3	Forecasted CBP Auction Rates	$44.86	$58.01	$61.70	$64.07	$65.75		Second Revised Exhibit RJM-1
4								
5	CBP Rate Blending Schedule (%)							
6	MRO	10.0%	20.0%	30.0%	40.0%	50.0%		Second Revised Exhibit RJM-1
7	ESP	10.0%	40.0%	70.0%	100.0%	100.0%		Second Revised Exhibit RJM-1
8								
9	Blended SSO Rate ($/MWh)							
10	MRO	$73.44	$72.90	$72.14	$71.60	$71.19		Line 2*(1-Line 6)+Line 3*Line 6
11	ESP	$73.44	$69.18	$66.18	$64.07	$65.75		Line 2*(1-Line 7)+Line 3*Line 7
12	Difference in Bypassable Rates	$0.00	-$3.72	-$5.97	-$7.53	-$5.44		Line 10 - Line 11
13								
14	Total Bypassable Revenues ($Millions)							
15	MRO	$304.55	$302.29	$299.16	$296.91	$295.18	$1,498.09	Line 10 * Line 35
16	ESP	$304.55	$286.85	$274.41	$265.68	$272.65	$1,404.15	Line 11 * Line 35
17	Difference in Bypassable Revenues	$0.00	-$15.43	-$24.75	-$31.22	-$22.54	-$93.94	Line 16 - Line 15
18								
19	Non-bypassable Revenues ($Millions)							
20	MRO	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	Direct Testimony of Kevin Murray
21	ESP	$137.50	$137.50	$137.50	$137.50	$137.50	$687.50	Second Revised Exhibit RJM-1
22	Difference in Non-bypassable Revenues	$137.50	$137.50	$137.50	$137.50	$137.50	$687.50	Line 21 - Line 20
23								
24	ESP Versus MRO Price Test ($Millions)							
25	*Difference in Bypassable Revenues*	$0.00	-$15.43	-$24.75	-$31.22	-$22.54	-$93.94	Line 17
26	Difference in Non-bypassable Revenues	$137.50	$137.50	$137.50	$137.50	$137.50	$687.50	Line 18
27	*Forecast Switching Tracker Revenue Requirement ($ Millions)*	$36.43	$21.35	$17.12	$0.00	$0.00	$74.90	Line 40
28	**Total Change in Revenues**	$173.93	$143.41	$129.87	$106.28	$114.96	$668.45	Line 25 + Line 26 + Line 27
29								
30	**Load and Switching Assumptions**							
31								
32	August 30, 2012 Switching	61.7%	61.7%	61.7%	61.7%	61.7%		(1 - Line 32)/Line 33
33	August 30, 2012 DP&L SSO Load (TWh)	5.29	5.29	5.29	5.29	5.29		Second Revised Exhibit RJM-1 w/ adjustment to first CBP
34	Total Load (TWh)	13.82	13.82	13.82	13.82	13.82		Second Revised Exhibit RJM-1 w/ adjustment to first CBP
35	Forecast Switching	70.0%	70.0%	70.0%	70.0%	70.0%		
36	Forecast SSO Load	4.15	4.15	4.15	4.15	4.15		(1-Line 37)* Line 36
37	Forecast Switching Tracker Revenue Requirement ($ Millions)	$36.43	$21.35	$17.12			$74.90	(Line 36 - Line 39)*(Line 5-Line 6)

Exhibit KMM-18

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2010

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

Each of the following classes or series of securities registered pursuant to Section 12 (b) of the Act is registered on the New York Stock Exchange:

Registrant	Description
DPL Inc.	**Common Stock, $0.01 par value and Preferred Share Purchase Rights**
The Dayton Power and Light Company	**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 ☐

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

DPL Inc.	Yes ☒	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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" 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 ☒

The aggregate market value of DPL Inc.'s common stock held by non-affiliates of DPL Inc. as of June 30, 2010 was approximately $2.8 billion based on a closing sale price of $23.90 on that date as reported on the New York Stock Exchange. All of the common stock of The Dayton Power and Light Company is owned by DPL Inc. As of February 15, 2011, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares Outstanding
DPL Inc.	**Common Stock, $0.01 par value and Preferred Share Purchase Rights**	116,931,350
The Dayton Power and Light Company	**Common Stock, $0.01 par value**	41,172,173

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.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of DPL's definitive proxy statement for its 2011 Annual Meeting of Shareholders are incorporated by reference in Part III of this Form 10-K.

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DPL Inc. and The Dayton Power and Light Company
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Fiscal Year Ended December 31, 2010

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
BTU	British Thermal Units
CFTC	Commodity Futures Trading Commission
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CSP	Columbus Southern Power, a subsidiary of AEP
CO_2	Carbon Dioxide
CCEM	Customer Conservation and Energy Management
CRES	Competitive Retail Electric Service
DPL	DPL Inc., the parent company
DPLE	DPL Energy, LLC, a wholly owned subsidiary of DPL which engages in the operation of peaking generation facilities
DPLER	DPL Energy Resources, Inc., a wholly owned subsidiary of DPL which sells retail electric energy and other energy services
DP&L	The Dayton Power and Light Company, the principal subsidiary of DPL and a public utility which sells electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio
Duke Energy	Duke Energy Ohio, Inc., formerly The Cincinnati Gas & Electric Company (CG&E)
EIR	Environmental Investment Rider
EPS	Earnings Per Share
ESP Stipulation	A Stipulation and Recommendation filed by **DP&L** with the PUCO on February 24, 2009 regarding **DP&L's** ESP filing pursuant to SB 221. The Stipulation was signed by the Staff of the PUCO, the Office of the Ohio Consumers' Counsel and various intervening parties. The PUCO approved the Stipulation on June 24, 2009.
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plans, filed with the PUCO, pursuant to Ohio law
FASB	Financial Accounting Standards Board
FASC	FASB Accounting Standards Codification
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FTRs	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
kWh	Kilowatt hours
LOC	Letter of Credit

Abbreviation or Acronym	Definition
MRO	Market Rate Option
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
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority
OCC	Ohio Consumers' Counsel
ODT	Ohio Department of Taxation
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, a regional transmission organization
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
RSU	Restricted Stock Units
RTO	Regional Transmission Organization
RPM	Reliability Pricing Model
SB 221	Ohio Senate Bill 221, an Ohio electric energy bill that was signed by the Governor on May 1, 2008 and went into effect July 31, 2008. This law required all Ohio distribution utilities to file either an ESP or MRO to be in effect January 1, 2009. The law also contains, among other things, annual targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SECA	Seams Elimination Charge Adjustment
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur Dioxide
SSO	Standard Service Offer which represents the regulated rates, authorized by the PUCO, charged to retail customers within **DP&L's** service territory.
TCRR	Transmission Cost Recovery Rider
USEPA	U.S. Environmental Protection Agency
USF	Universal Service Fund
VRDN	Variable Rate Demand Note

PART I

Item 1 — Business

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

WEBSITE ACCESS TO REPORTS

We file current, annual and quarterly reports and other information required by the Securities Exchange Act of 1934, as amended, with the SEC. You may read and copy any document we file at the SEC's public reference room located at 100 F Street N.E., Washington, D.C. 20549, USA. Please call the SEC at (800) SEC-0330 for further information on the public reference rooms. Our SEC filings are also available to the public from the SEC's website at http://www.sec.gov.

Our public internet site is http://www.dplinc.com. We make available, free of charge, through our internet site, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and Forms 3, 4 and 5 filed on behalf of our directors and executive officers and amendments to those reports filed or furnished pursuant to the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

In addition, our public internet site includes other items related to corporate governance matters, including, among other things, our governance guidelines, charters of various committees of the Board of Directors and our code of business conduct and ethics applicable to all employees, officers and directors. You may obtain copies of these documents, free of charge, by sending a request, in writing, to DPL Investor Relations, 1065 Woodman Drive, Dayton, Ohio 45432.

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. Please see page 37 for more information about forward-looking statements contained in this report.

ORGANIZATION

DPL is a regional energy company organized in 1985 under the laws of Ohio. Our executive offices are located at 1065 Woodman Drive, Dayton, Ohio 45432 — telephone (937) 224-6000.

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

During 2010, **DPL**, for the first time, met the GAAP requirements for separate segment reporting. **DPL's** two segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary. Refer to Note 17 of Notes to Consolidated Financial Statements for more information relating to these reportable segments. **DP&L** does not have any reportable segments.

DPLER sells competitive retail electric service, under contract, primarily to commercial and industrial customers. DPLER has approximately 9,000 customers currently located throughout Ohio. All of DPLER's electric energy was purchased from **DP&L** to meet these sales obligations. During 2010, we implemented a new wholesale agreement between **DP&L** and DPLER. Under this agreement, intercompany sales from **DP&L** to DPLER were based on the market prices for wholesale power. In 2009 and prior periods, DPLER's purchases from **DP&L** were transacted at prices that approximated DPLER's sales prices to its end-use retail customers. The operations of DPLER are not subject to rate regulation by federal or state regulators.

DPL's other significant subsidiaries (all of which are wholly-owned) include: DPLE, which engages in the operation of peaking generating facilities and sells power in wholesale markets and MVIC, which is our captive insurance company that provides insurance to us and our 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 recoveries in customer rates relate to expected future costs.

DPL and its subsidiaries employed 1,494 persons as of January 31, 2011, of which 1,321 were full-time employees and 173 were part-time employees. At that date, 1,298 of these full-time employees and substantially all of the part-time employees were employed by **DP&L**. Approximately 54% of the employees are under a collective bargaining agreement.

SIGNIFICANT DEVELOPMENTS

Borrowing Activities

On April 20, 2010, **DP&L** entered into a $200 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on April 20, 2013 and provides **DP&L** with the ability to increase the size of the facility by an additional $50 million. The facility contains one financial covenant: **DP&L's** total debt to total capitalization ratio is not to exceed 0.65 to 1.00. This facility also contains a $50 million letter of credit sublimit.

On December 1, 2010, **DP&L** renewed two $50 million LOC agreements with JPMorgan Chase Bank, N.A. These agreements are for three years, expiring December 9, 2013. The irrevocable LOC's continue to back the payment of principal and interest relating to the $100 million State of Ohio Collateralized Air Quality Development Revenue Refunding Bonds, 2008 Series A and B which are due in November 2040.

Stock Repurchase Plan

On October 27, 2010, the **DPL** Board of Directors approved a new stock repurchase plan to acquire up to $200 million of **DPL** common stock. Under this plan, **DPL** may repurchase its common stock from time to time in the open market, through private transactions or otherwise, on such terms and conditions as the company deems appropriate. The company expects to subject the purchases to restrictions relating to volume, price and timing in an effort to minimize the impact of the purchases upon the market for its common stock. **DPL** intends to fund purchases from cash on hand, available borrowings, cash flow from operations and proceeds from potential debt or other capital market transactions. The plan will run through December 31, 2013, but may be modified or terminated at any time without prior notice. Through December 31, 2010, **DPL** repurchased approximately 2.04 million shares of common stock under this stock repurchase plan at an average price per share of $25.75.

Construction of Yankee Solar Facility

On April 23, 2010, **DP&L's** Yankee solar station, a certified Ohio Renewable Energy Resource Generating Facility, was placed into service. The Yankee facility is comprised of 9,120 solar panels constructed over approximately 7 acres of land located in the Dayton, Ohio area. The facility is expected to generate approximately 1,390 MWh of electric energy per year which is sufficient to power the equivalent of approximately 150 homes a year.

Customer Switching

During 2010, there were 4 additional unaffiliated marketers that registered as CRES providers in **DP&L's** service territory. We have experienced increased competition to provide transmission and generation services to our retail customers. DPLER, a CRES provider that is also a subsidiary of **DPL**, accounted for approximately 97% of the total retail energy supplied by CRES providers within **DP&L's** service territory in 2010. During 2010, 847 customers with an energy usage of 145 million kWh were supplied by other CRES providers within **DP&L's** service territory, compared to 44 customers that had an energy usage of 16 million kWh during 2009. For the year ended December 31, 2010, the reduction in **DPL's** and **DP&L's** gross margin as a result of customers switching to DPLER and other CRES providers is estimated to be approximately $17 million and $53 million, respectively.

Increase in Dividends on DPL's Common Stock

On December 8, 2010, **DPL's** Board of Directors authorized a quarterly dividend rate increase of approximately 10%, increasing the quarterly dividend per **DPL** common share from $.3025 to $.3325. If this dividend rate is maintained, the annualized dividend would increase from $1.21 per share to $1.33 per share.

ELECTRIC OPERATIONS AND FUEL SUPPLY

	2010 Summer Generating Capacity		
(Amounts in MWs)	*Coal Fired*	*Peaking Units*	*Total*
DPL	2,830	988	3,818
DP&L	2,830	431	3,261

DPL's present summer generating capacity, including peaking units, is approximately 3,818 MW. Of this capacity, approximately 2,830 MW, or 74%, is derived from coal-fired steam generating stations and the balance of approximately 988 MW, or 26%, consists of solar, combustion turbine and diesel peaking units.

DP&L's present summer generating capacity, including peaking units, is approximately 3,261 MW. Of this capacity, approximately 2,830 MW, or 87%, is derived from coal-fired steam generating stations and the balance of approximately 431 MW, or 13%, consists of solar, combustion turbine and diesel peaking units.

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

Approximately 87% of the existing steam generating capacity is provided by certain generating units owned as tenants in common with Duke Energy and CSP. 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. **DP&L's** remaining steam generating capacity (approximately 365 MW) is derived from a generating station owned solely by **DP&L**. Additionally, **DP&L**, Duke Energy and CSP own, as tenants in common, 884 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 2010, we generated 98.9% of our electric output from coal-fired units and 1.1% from solar, oil and natural gas-fired units.

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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*	Operating Company	Location	Approximate Summer MW Rating DPL Portion	Approximate Summer MW Rating Total
Coal Units					
Hutchings	W	DP&L	Miamisburg, OH	365	365
Killen	C	DP&L	Wrightsville, OH	402	600
Stuart	C	DP&L	Aberdeen, OH	808	2,308
Conesville-Unit 4	C	CSP	Conesville, OH	129	780
Beckjord-Unit 6	C	Duke Energy	New Richmond, OH	207	414
Miami Fort-Units 7 & 8	C	Duke Energy	North Bend, OH	368	1,020
East Bend-Unit 2	C	Duke Energy	Rabbit Hash, KY	186	600
Zimmer	C	Duke Energy	Moscow, OH	365	1,300
Solar, Combustion Turbines or Diesel					
Hutchings	W	DP&L	Miamisburg, OH	25	25
Yankee Street	W	DP&L	Centerville, OH	101	101
Yankee Solar	W	DP&L	Centerville, OH	1	1
Monument	W	DP&L	Dayton, OH	12	12
Tait Diesels	W	DP&L	Dayton, OH	10	10
Sidney	W	DP&L	Sidney, OH	12	12
Tait Units 1-3	W	DP&L	Moraine, OH	256	256
Killen	C	DP&L	Wrightsville, OH	12	18
Stuart	C	DP&L	Aberdeen, OH	3	10
Montpelier Units 1-4	W	DPLE	Poneto, IN	236	236
Tait Units 4-7	W	DPLE	Moraine, OH	320	320
Total approximate summer generating capacity				3,818	8,388

*W = Wholly-Owned

C = Commonly-Owned

In addition to the above, **DP&L** also owns a 4.9% equity ownership interest in OVEC, an electric generating company. OVEC has two plants in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of approximately 2,265 MW. **DP&L's** share of this generation capacity is approximately 111 MW.

We have substantially all of the total expected coal volume needed to meet our retail and firm wholesale sales requirements for 2011 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 outages and generation plant mix. Due to the installation of emission controls equipment at certain jointly owned units and barring any changes in the regulatory environment in which we operate, we expect to have a balanced SO_2 and NOx position for 2011.

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

	Average Cost of Fuel Consumed (¢/kWh)		
	2010	2009	2008
DPL	**2.42**	2.39	2.28
DP&L	**2.37**	2.36	2.22

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 as compared to other times of the year. Unusually mild summers and winters could have an adverse effect on our results of operations, financial condition and cash flows.

RATE REGULATION AND GOVERNMENT LEGISLATION

DP&L's sales to SSO retail customers are subject to rate regulation by the PUCO. **DP&L's** transmission rates and wholesale electric rates to municipal corporations, rural electric co-operatives and other distributors of electric energy are subject to regulation by the FERC under the Federal Power Act.

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

Ohio legislation extends the jurisdiction of the PUCO to the records and accounts of certain public utility holding company systems, including **DPL**. The legislation extends the PUCO's supervisory powers to a holding company system's general condition and capitalization, among other matters, to the extent that such matters relate to the costs associated with the provision of public utility service. Based on existing PUCO and FERC authorization, regulatory assets and liabilities are recorded on the balance sheets. See Note 3 of Notes to Consolidated Financial Statements.

COMPETITION AND REGULATION

Ohio Matters

Ohio Retail Rates

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

On May 1, 2008, substitute SB 221, an Ohio electric energy bill, was signed by the Governor and went into effect July 31, 2008. This law required that all Ohio distribution utilities file either an ESP or MRO. Under the MRO, a periodic competitive bid process will set the retail generation price after the utility demonstrates that it can meet certain market criteria and bid requirements. Also, under this option, utilities that still own generation in the state are required to phase-in the MRO over a period of not less than five years. An ESP may allow for adjustments to the SSO for costs associated with environmental compliance; fuel and purchased power; construction of new or investment in specified generating facilities; and the provision of standby and default service, operating, maintenance, or other costs including taxes. As part of its ESP, a utility is permitted to file an infrastructure improvement plan that will specify the initiatives the utility will take to rebuild, upgrade, or replace its electric distribution system, including cost recovery mechanisms. Both the MRO and ESP option involve a "significantly excessive earnings test" based on the earnings of comparable companies with similar business and financial risks. The PUCO issued three sets of rules related to implementation of the law. These rules address topics such as the information that must be included in an ESP as well as a MRO, the significantly excessive earnings test requirements, corporate separation revisions, rules relating to the recovery of transmission related costs, electric service and safety standards dealing with the statewide line extension policy, and rules relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards.

In compliance with SB 221, **DP&L** filed its ESP at the PUCO on October 10, 2008. This plan contained three parts: 1) a standard offer plan; 2) a CCEM plan; and 3) an alternative energy plan. After discussions with Commission Staff, the Ohio Consumers' Counsel and other interested parties, an ESP Stipulation was agreed to and filed on February 24, 2009. The ESP Stipulation, among other things, extended the Company's rate plan through 2012, provided for recovery of the Ohio retail customers' portion of fuel and purchased power costs beginning January 2010, provided for recovery of certain SB 221 compliance costs, and required **DP&L** to re-file its Smart Grid and advanced metering infrastructure (AMI) business cases, which were part of the CCEM plan, by September 1, 2009. On June 24, 2009, the PUCO issued an order granting approval of the ESP Stipulation as filed and authorized **DP&L** to implement rates associated with alternative energy and energy efficiency compliance costs, which **DP&L** implemented beginning on July 1, 2009.

Consistent with the ESP Stipulation, **DP&L** re-filed its Smart Grid and AMI business cases with the PUCO on August 4, 2009 seeking recovery of costs associated with a three-year plan to deploy AMI; and a ten-year plan for distribution and substation automation, core telecommunications, supporting software and in-home technologies. In August 2009, **DP&L** submitted an application for American Recovery and Reinvestment Act (ARRA) funding for the Smart Grid Investment Grant Program, seeking $145.1 million of matching funds but was notified in October 2009, that we would not receive funding under the ARRA. On October 19, 2010, **DP&L** elected to withdraw the re-filed case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects **DP&L** to continue to monitor other utilities' Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that **DP&L** will, when appropriate, file new Smart Grid and/or AMI business cases in the future.

SB 221 and the implementation rules contain targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards. If any targets are not met, compliance penalties will apply unless the PUCO makes certain findings that would excuse performance. In December 2009, **DP&L** made several filings relating to its renewable energy and energy efficiency compliance plans. **DP&L** was able to obtain Renewable Energy Credits sufficient to meet its non-solar renewable energy targets, but obtained only 36% of the 2009 Ohio-based solar resources. **DP&L** requested a waiver of any unmet 2009 Ohio solar requirements on grounds of force majeure because there were insufficient solar renewable energy credits available from Ohio resources. In March 2010, the PUCO ruled that **DP&L**'s 2009 Ohio solar target would be reduced to the amount that it had procured, but that any unmet requirement must be added to the 2010 target. **DP&L** has been able to acquire sufficient renewable resources in 2010 to meet its 2010 requirements plus that portion of the 2009 Ohio solar requirement that was added by the PUCO order.

On April 15, 2010, **DP&L** made its first annual required filing related to compliance with renewable and advanced energy targets contained in SB 221. Pursuant to PUCO rules, each April 15, **DP&L** and DPLER who are electric services companies pursuant to Ohio Revised Code, are required to provide a status report on whether or not they met the renewable benchmarks of the previous year, as well as a ten-year plan outlining their plans to meet future annual renewable targets. In addition, on April 15 of each year, each utility that owns an electric generating facility in Ohio must report to the PUCO regarding its greenhouse gas emissions, and plans to reduce those emissions (environmental control plan) as well as a long-term forecast report which includes a plan to provide sufficient resources to meet customer load obligations (resource plan). **DP&L's** long-term forecast filing was set for hearing. A settlement was reached in early 2011 under which the need for solar facilities was established. This settlement was filed with the PUCO for their approval.

In two separate filings, **DP&L** requested the PUCO's consent that **DP&L** had met the 2009 requirements for energy efficiency and for demand reduction based on **DP&L's** interpretation of how those requirements should be applied. These filings also requested that if the PUCO disagreed with **DP&L's** interpretation, the PUCO grant alternative relief and find that **DP&L** was unable to meet the targets due to reasons beyond its reasonable control, i.e., uncertainty throughout 2009 caused by delays in finalizing the rules and the lack of timely PUCO action on several of **DP&L's** special contracts relating to demand response efforts which remain pending before the PUCO. Since this is a new process, it is unclear if a final order will be issued in these proceedings.

In addition, the rules that became effective December 10, 2009 required that on January 1, 2010, **DP&L** file an extensive energy efficiency portfolio plan, outlining how **DP&L** plans to comply with the energy efficiency and demand reduction benchmarks. **DP&L** filed a separate request for a finding that it had already complied with this requirement in the form of **DP&L's** portfolio plan that had been filed in 2008 as part of its CCEM plan, which had been approved by the PUCO and is being implemented. On May 19, 2010 the Commission approved in part and denied in part **DP&L's** request that the Commission find that it met the 2009 energy efficiency portfolio requirements and directed **DP&L** to file a measurement and verification plan as well as a market potential study within 60 days of the date of the order. We made this filing on July 15, 2010. Although this case was set for hearing settlement talks are on-going.

We are unable to predict how the PUCO will respond to many of the filings discussed above, but believe that the outcome will not be material to our financial condition. However, as the energy efficiency and alternative energy targets get increasingly larger over time, the costs of complying with SB 221 and the PUCO's implementing rules could have a material impact on our financial condition.

The ESP Stipulation also provided for the establishment of a fuel and purchased power recovery rider beginning January 1, 2010. The fuel rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter: March 1, June 1, September 1 and December 1 each year. **DP&L** is currently undergoing an audit of its fuel rider which is conducted by an independent third party in accordance with the PUCO standards. As a result there is some uncertainty as to the costs that will be approved for recovery. **DP&L** anticipates that some of this uncertainty will be resolved during the summer of 2011 after completion of the fuel audit. Based on the results of the audit, **DP&L** may record a favorable or unfavorable adjustment to earnings. It is too early to determine if any such adjustment would be material to our results of operations, financial condition and cash flows.

As a member of PJM, **DP&L** receives revenues from the RTO related to its transmission and generation assets and incurs costs associated with its load obligations for retail customers. SB 221 included 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. Both the TCRR and the RPM riders assign costs and revenues from PJM monthly bills to retail ratepayers based on the percentage of SSO retail customers' load and sales volumes to total retail load and total retail and wholesale volumes. Customer switching to CRES providers decreases **DP&L's** SSO retail customers' load and sales volumes. Therefore, increases in customer switching cause more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. RPM capacity costs and revenues are discussed further under "Regional Transmission Organizational Risks" in Item 1A — Risk Factors. **DP&L's** annual true-up of these two riders was approved by the PUCO by an order dated April 28, 2010. On October 15, 2010 **DP&L** made an interim adjustment to both the TCRR and the RPM riders that had no material change to the rate recovery amounts.

On September 9, 2009, the PUCO issued an order establishing a significantly excessive earnings test (SEET) proceeding pursuant to provisions contained in SB 221. A question and answer session was held before the Commission on April 1, 2010 to allow the Commission to gain a better understanding of the issues. The PUCO issued an order on June 30, 2010 to establish general rules for calculating the earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings. The other three Ohio utilities were required to make their SEET determinations in 2010 based on 2009 results. Pursuant to the ESP Stipulation, **DP&L** becomes subject to the SEET in 2013 based on 2012 earnings results and the SEET may have a material impact on operations.

On August 28, 2009, **DP&L** filed its application to establish reliability targets consistent with the most recent PUCO Electric Service and Safety Standards (ESSS). The PUCO issued a procedural schedule and held a technical conference in November 2009. Comments and reply comments were filed. On March 29, 2010 **DP&L** entered into a settlement establishing the new reliability targets. This settlement was approved on July 29, 2010. According to the ESSS rules, **DP&L** will be subject to financial penalties if the established targets are not met for two consecutive years.

While the overall financial impact of SB 221 will not be known for some time, implementation of the bill and compliance with its requirements could have a material impact on our financial condition.

Ohio Competitive Considerations and Proceedings

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

Overall power market prices, as well as government aggregation initiatives within **DP&L's** service territory, have led or may lead to the entrance of additional competitors in our service territory. During the year ended December 31, 2010, there were four additional unaffiliated marketers that registered as CRES providers in **DP&L's** service territory, bringing the total number of CRES providers in **DP&L's** service territory to eleven. DPLER, an affiliated company and one of the eleven registered CRES providers, has been marketing transmission and generation services to **DP&L** customers. During 2010, DPLER accounted for approximately 4,417 million kWh of the total 4,562 million kWh supplied by CRES providers within **DP&L's** service territory. Also during 2010, 847 customers with an annual energy usage of 145 million kWh were supplied by other CRES providers within **DP&L's** service territory, compared to 44 customers that had an annual energy usage of 16 million kWh during 2009. The volume supplied by DPLER represents approximately 31% of **DP&L's** total distribution sales volume during 2010. The reduction to gross margin in 2010 as a result of customers switching to DPLER and other CRES providers was approximately $17 million and $53 million, for **DPL** and **DP&L**, respectively. We currently cannot determine the extent to which customer switching to CRES providers will occur in the future and the impact this will have on our operations, but any additional switching could have a significant adverse effect on our future results of operations, financial condition and cash flows.

Several communities in **DP&L's** service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering alternative electric generation supplies to their citizens. To date, none of these communities have aggregated their generation load.

In 2010, DPLER began providing CRES services to business customers in Ohio who are not in **DP&L's** service territory. The incremental costs and revenues have not had a material impact on our results of operations, financial condition or cash flows.

Federal Matters

Like other electric utilities and energy marketers, **DP&L** and DPLE may sell or purchase electric products on the wholesale market. **DP&L** and DPLE compete with other generators, power marketers, privately and municipally-owned electric utilities and rural electric cooperatives when selling electricity. The ability of **DP&L** and DPLE to sell this electricity will depend not only on the performance of our generating units, but also on how **DP&L's** and DPLE's price, 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 are required to join a RTO. In October 2004, **DP&L** successfully integrated its 1,000 miles of high-voltage transmission 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 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, administers the world's largest competitive wholesale electricity market and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.
The PJM RPM capacity base residual auction for the 2013/2014 period cleared at a per megawatt price of $28/day for our RTO area. The per megawatt prices for the periods 2012/2013, 2011/2012 and 2010/2011 were $16/day, $110/day and $174/day, respectively, based on previous auctions. Future RPM auction results will be dependent not only on the overall supply and demand of generation and load, but may also be impacted by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions. Increases in customer switching causes more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. We cannot predict the outcome of future auctions or customer switching but if the current auction price is sustained, our future results of operations, financial condition and cash flows could have a material adverse impact.
As a member of PJM, **DP&L** is also subject to charges and costs associated with PJM operations as approved by the FERC. FERC Orders issued in 2007 and thereafter regarding the allocation of costs of large transmission facilities within PJM, would result in additional costs being allocated to **DP&L** that, over time and depending on final costs and how quickly the facilities are constructed, could become material. **DP&L** filed a notice of appeal to the U.S. Court of Appeals, D.C. Circuit which was consolidated with other appeals taken by other interested parties of the same FERC Orders and the consolidated cases were assigned to the 7th Circuit. On August 6, 2009, the 7th Circuit ruled that the FERC had failed to provide a reasoned basis for the allocation method it had approved. Rehearings were filed by other interested litigants and denied by the Court, which then remanded the matter to the FERC for further proceedings. On January 21, 2010, the FERC issued a procedural order on remand establishing a paper hearing process under which PJM will make an informational filing in late February. Subsequently PJM and other parties, including **DP&L**, filed initial comments, testimony, and recommendations and reply comments. FERC did not establish a deadline for its issuance of a substantive order and the matter is still pending. **DP&L** cannot predict the timing or the likely outcome of the proceeding. Until such time as FERC may act to approve a change in methodology, PJM will continue to apply the allocation methodology that had been approved by FERC in 2007. Although we continue to maintain that these costs should be borne by the beneficiaries of these projects and that **DP&L** is not one of these beneficiaries, any new credits or additional costs resulting from the ultimate outcome of this proceeding will be reflected in **DP&L's** TCRR rider which already includes these costs.
NERC is a FERC-certified electric reliability organization responsible for developing and enforcing mandatory reliability standards, including Critical Infrastructure Protection (CIP) reliability standards, across eight reliability regions. In June 2009, Reliability First Corporation (RFC), with responsibilities assigned to it by NERC over the reliability region that includes **DP&L**, commenced a routine audit of **DP&L's** operations. The audit, which was for the period June 18, 2007 to June 25, 2009, evaluated **DP&L's** compliance with 42 requirements in 18 NERC-reliability standards. **DP&L** is currently subject to a compliance audit at a minimum of once every three years as provided by the NERC Rules of Procedure. This audit was concluded in June 2009 and its findings revealed that **DP&L** had some Possible Alleged Violations (PAVs) associated with five NERC reliability requirements of various Standards. In response to the report, **DP&L** filed mitigation plans with RFC/NERC to address the PAVs. These mitigation plans were accepted by RFC/NERC. In July 2010, **DP&L** negotiated a settlement with NERC wherein **DP&L** agreed to pay an immaterial amount in exchange for a resolution of all issues and obligations relating to the aforementioned PAVs. The settlement was approved on January 21, 2011 by the FERC.

ENVIRONMENTAL CONSIDERATIONS

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

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

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 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 estimated accruals for loss contingencies of approximately $4.0 million for environmental matters. We also have a number of unrecognized loss contingencies related to environmental matters that are disclosed in the paragraphs below. We evaluate the potential liability related to environmental matters quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material effect on our results of operations, financial condition or cash flows.

In July 2010, the USEPA proposed new rules to limit the interstate transport of emissions of NOx and SO_2 that would, if finalized, have a significant industry-wide impact on the operation of coal-fired generation units. We also have several other pending environmental matters associated with our coal-fired generation units and these pending matters, along with the new rules proposed by the USEPA, could result in significant capital and operations and maintenance expenditures for our coal-fired generation plants, and could result in the early retirement of our generation units that do not have SCR and FGD equipment installed. Currently, our coal-fired generation units at Hutchings and Beckjord do not have this emission-control equipment installed and their early retirement could occur as early as 2015. **DP&L** owns 100% of the Hutchings plant and has a 50% interest in Beckjord Unit 6. In addition to environmental matters, the operation of our coal-fired generation plants could be impacted by a multitude of other factors, including forecasted power, capacity and commodity prices, competition and the levels of customer switching, current and forecasted customer demand, cost of capital, and regulatory and legislative developments, any of which could pose a potential triggering event for an impairment of our investments in the Hutchings and Beckjord units.

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Regulation Matters Related to Air Quality

Clean Air Act Compliance

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

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

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

Interstate Air Quality Rule

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

On July 6, 2010, the USEPA proposed the Clean Air Transport Rule (CATR) which may replace CAIR in 2012. We have reviewed this proposal and submitted comments to the USEPA on September 30, 2010. We are unable to determine the overall financial impact that these rules could have on our operations in the future.

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

Mercury and Other Hazardous Air Pollutants

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

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

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

National Ambient Air Quality Standards

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

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

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

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

Effective August 23, 2010, the USEPA implemented revisions to its primary NAAQS for SO_2 replacing the current 24-hour standard and annual standard with a one hour standard. **DP&L** cannot determine the effect of this potential change, if any, on its operations.

Climate Change

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

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

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

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

Litigation Involving Co-Owned Plants

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

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

Notices of Violation Involving Co-Owned Plants

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

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

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

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

Other Issues Involving Co-Owned Plants

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

Notices of Violation Involving Wholly-Owned Plants

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

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

Regulation Matters Related to Water Quality

Clean Water Act — Regulation of Water Intake

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

Clean Water Act — Regulation of Water Discharge

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

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

Regulation Matters Related to Land Use and Solid Waste Disposal

Regulation of Waste Disposal

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

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

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

Regulation of Ash Ponds

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

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

Similarly, in August 2010, the USEPA conducted an inspection of the O.H. Hutchings Station ash ponds. The draft report relating to the inspection was received in November 2010 and **DP&L** provided comments on the draft report in December 2010. **DP&L** is unable to predict the outcome this inspection will have on its operations.

In addition, as a result of the TVA ash pond spill, there has been increasing advocacy to regulate coal combustion byproducts under the Resource Conservation Recovery Act (RCRA). On June 21, 2010, the USEPA published a proposed rule seeking comments on two options under consideration for the regulation of coal combustion products including regulating the material as a hazardous waste under RCRA Subtitle C or as a solid waste under RCRA Subtitle D. **DP&L** is unable to predict the financial impact of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse impact on operations.

Other Legal Matters

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

On May 16, 2007, **DPL** filed a claim with Energy Insurance Mutual (EIM) to recoup legal costs associated with our litigation against certain former executives. On February 15, 2010, after having engaged in both mediation and arbitration, **DPL** and EIM entered into a settlement agreement resolving all coverage issues and finalizing all obligations in connection with the claim, under which **DPL** received $3.4 million (net of associated expenses).

In connection with **DP&L** and other utilities joining PJM, in 2006 the FERC ordered utilities to eliminate certain charges to implement transitional payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, **DP&L** was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments. A hearing was held and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010 that substantially supports **DP&L's** and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. **DP&L**, along with other transmission owners in PJM and the Midwest Independent System Operator (MISO) made a compliance filing at FERC on August 19, 2010 that fully demonstrated all payment obligations to and from all parties within PJM and the MISO. The FERC has made no ruling regarding the compliance filing and some parties have requested rehearing by FERC of its May 21, 2010 order. It is expected that any order on the compliance filing and any order regarding the rehearing request will be appealed for Court review. Prior to this final order being issued, **DP&L** entered into a significant number of bi-lateral settlement agreements with certain parties to resolve the matter, which by design will be unaffected by the final decision. Further, in October 2010, **DP&L** entered into another settlement agreement to settle a portion of SECA amounts still owed to **DP&L**. With respect to unsettled claims, **DP&L** management believes it has deferred as a regulatory liability the appropriate amounts that are subject to refund (see SECA net revenue subject to refund within Note 3 of Notes to Consolidated Financial Statements) and therefore the results of this proceeding are not expected to have a material adverse effect on **DP&L's** results of operations.

Capital Expenditures for Environmental Matters

Test operations of the FGD equipment on our jointly-owned Conesville Unit 4 were completed in November 2009. The equipment is currently in service.

DPL's construction additions were approximately $151 million, $145 million and $228 million in 2010, 2009 and 2008, respectively, and are expected to approximate $310 million in 2011. Planned construction additions for 2011 relate primarily to new investments in and upgrades to **DP&L's** power plant equipment and transmission and distribution system.

DP&L's construction additions were $148 million, $144 million and $225 million in 2010, 2009 and 2008, respectively, and are expected to approximate $300 million in 2011. Planned construction additions for 2011 relate primarily to new investments in and upgrades to **DP&L's** power plant equipment and transmission and distribution system.

All environmental additions made during the past three years pertain to **DP&L** and approximated $12 million, $21 million and $90 million in 2010, 2009 and 2008, respectively.

ELECTRIC SALES AND REVENUES

The following table sets forth **DPL's**, **DP&L's** and DPLER's electric sales and revenues for the years ended December 31, 2010, 2009 and 2008, respectively.

	DPL			DP&L (a)			DPLER (b)		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
Electric sales (millions of kWh)									
Residential	5,522	5,120	5,533	5,522	5,120	5,533	1	—	—
Commercial	3,842	3,678	3,959	3,741	3,678	3,959	1,194	68	421
Industrial	3,605	3,353	3,986	3,582	3,353	3,986	2,476	983	2,322
Other retail	1,437	1,386	1,454	1,432	1,386	1,454	875	413	469
Total retail	14,406	13,537	14,932	14,277	13,537	14,932	4,546	1,464	3,212
Wholesale	2,831	3,130	2,240	2,806	3,053	2,173	—	—	—
Total	17,237	16,667	17,172	17,083	16,590	17,105	4,546	1,464	3,212
Operating revenues ($ in thousands)									
Residential	$ 687,932	$ 560,223	$ 544,561	$ 687,891	$ 560,223	$ 544,561	$ 41	$ —	$ —
Commercial	384,385	332,808	332,010	304,078	329,006	308,934	80,307	3,802	23,076
Industrial	260,763	228,458	240,041	118,517	186,293	133,832	142,246	42,165	106,209
Other retail	113,550	98,781	97,592	64,240	82,749	78,905	52,811	18,871	21,338
Other miscellaneous revenues	9,814	8,766	9,042	10,723	8,966	9,046	57	—	64
Total retail	1,456,444	1,229,036	1,223,246	1,185,449	1,167,237	1,075,278	275,462	64,838	150,687
Wholesale	142,312	122,519	149,874	365,798	181,871	293,500	—	—	—
RTO revenues	272,832	225,677	217,357	239,274	201,254	204,074	1,503	615	31
Other revenues	11,534	11,689	11,080	—	—	—	27	95	88
Total	$ 1,883,122	$ 1,588,921	$ 1,601,557	$ 1,790,521	$ 1,550,362	$ 1,572,852	$ 276,992	$ 65,548	$ 150,806
Electric customers at end of period									
Residential	455,572	456,144	456,770	455,572	456,144	456,770	33	—	—
Commercial	50,764	50,141	50,190	50,155	50,141	50,190	7,205	223	432
Industrial	1,800	1,773	1,797	1,769	1,773	1,797	564	44	184
Other	6,742	6,577	6,517	6,739	6,577	6,517	1,200	123	126
Total	514,878	514,635	515,274	514,235	514,635	515,274	9,002	390	742

(a) ***DP&L*** *sold 4,417 million kWh, 1,464 million kWh and 3,212 million kWh of power to DPLER (a subsidiary of DPL) during the years ended December 31, 2010, 2009 and 2008, respectively, which are not included in* ***DP&L*** *wholesale sales volumes in the chart above. These kWh sales also relate to* ***DP&L*** *retail customers within the* ***DP&L*** *service territory for distribution services and their inclusion in wholesale sales would result in a double counting of kWh volume. The dollars of operating revenues associated with these sales are classified as wholesale revenues on* ***DP&L's*** *Financial Statements and retail revenues on* ***DPL's*** *Consolidated Financial Statements.*

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

Item 1A — Risk Factors

This annual report and other documents that we file with the SEC and other regulatory agencies, as well as other written or oral statements we may make from time to time, contain information based on management's beliefs and include forward-looking statements (within the meaning of the Private Securities Litigation Reform Act of 1995) that involve a number of known and unknown risks, uncertainties and assumptions. These forward-looking statements are not guarantees of future performance and there are a number of factors including, but not limited to, those listed below, which could cause actual outcomes and results to differ materially from the results contemplated by such forward-looking statements. We do not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. These forward-looking statements are generally identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will" and similar expressions.

Future operating results are subject to fluctuations based on a variety of factors, including but not limited to: unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages; changes in wholesale power sales prices; unusual maintenance or repairs; changes in fuel and purchased power costs, emissions allowance costs, or availability constraints; environmental compliance; and electric transmission system constraints.

The following is a listing of specific risk factors that **DPL** and **DP&L** consider to be the most significant to your decision to invest in our securities. If any of these events occur or are continuing, our business, results of operations, financial condition and cash flows could be materially affected.

Our customers have recently begun to select alternative electric generation service providers, as permitted by Ohio legislation.

Customers can elect to buy transmission and generation service from a PUCO-certified CRES provider offering services to customers in **DP&L's** service territory. DPLER, a wholly-owned subsidiary of **DPL**, is one of the PUCO-certified CRES providers and accounted for approximately 97% of the total retail energy supplied by CRES providers within **DP&L's** service territory in 2010. Unaffiliated CRES providers also have been certified to provide energy in **DP&L's** service territory and during 2010, approximately 800 **DP&L** customers switched their generation service to these providers. Customer switching from **DP&L** to DPLER reduces **DPL's** revenues since the generation rates charged by DPLER are less than the rates charged by **DP&L**. Increased competition by unaffiliated CRES providers in our service territory for retail generation service could result in the loss of existing customers and reduced revenues and increased costs to retain or attract customers. Decreased revenues and increased costs due to continued customer switching and customer loss could have a material adverse effect on our results of operations, financial condition and cash flows. The following are a few of the factors that could result in increased switching by customers to PUCO-certified CRES providers in the future:

- Low wholesale price levels may lead to existing CRES providers becoming more active in our service territory, and additional CRES providers entering our territory.
- We could also experience customer switching through "governmental aggregation," where a municipality may contract with a CRES provider to provide generation service to the customers located within the municipal boundaries.

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

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

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

The costs we can recover and the return on capital we are permitted to earn for certain aspects of our business are regulated and governed by the laws of Ohio and the rules, policies and procedures of the PUCO. On May 1, 2008, SB 221, an Ohio electric energy bill, was signed by the Governor of Ohio and became effective July 31, 2008. This law, among other things, required all Ohio distribution utilities to file either an ESP or MRO, and established a significantly excessive earnings test for Ohio public utilities that compares the utility's earnings to the earnings of other companies with similar business and financial risks. The PUCO approved **DP&L's** filed ESP on June 24, 2009. **DP&L's** ESP provides, among other things, that **DP&L's** existing rate plan structure will continue through 2012; that **DP&L** may seek recovery for adjustments to its existing rate plan structure for costs associated with storm damage, regulatory and tax changes, new climate change or carbon regulations, fuel and purchased power and certain other costs; and that SB 221's significantly excessive earnings test will apply in 2013 based upon **DP&L's** 2012 earnings. **DP&L's** ESP and certain filings made by us in connection with this plan are further discussed under "Ohio Retail Rates" in Item 1 — COMPETITION AND REGULATION. In addition, as the local distribution utility, **DP&L** has an obligation to serve customers within its certified territory and under the terms of its ESP Stipulation, it is the provider of last resort (POLR) for standard offer service. **DP&L's** current rate structure provides for a nonbypassable charge to compensate **DP&L** for this POLR obligation. The PUCO may decrease or discontinue this POLR rate charge at some time in the future.

While rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the PUCO will agree that all of our costs have been prudently incurred or are recoverable or that the regulatory process in which rates are determined will always result in rates that will produce a full or timely recovery of our costs and permitted rates of return. Certain of our cost recovery riders are also by-passable by some of our customers who switched to a CRES provider. Accordingly, the revenue **DP&L** receives may or may not match its expenses at any given time. Therefore, **DP&L** could be subject to prevailing market prices for electricity and would not necessarily be able to charge rates that produce timely or full recovery of its expenses. Changes in, or reinterpretations of, the laws, rules, policies and procedures that set electric rates, permitted rates of return and POLR service; changes in **DP&L's** rate structure and its ability to recover amounts for environmental compliance, POLR obligations, reliability initiatives, fuel and purchased power (which account for a substantial portion of our operating costs), customer switching, capital expenditures and investments and other costs on a full or timely basis through rates; and changes to the frequency and timing of rate increases could have a material adverse effect on our results of operations, financial condition and cash flows.

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

SB 221 contains targets relating to advanced energy, renewable energy, peak demand reduction and energy efficiency standards. The standards require that, by the year 2025 and each year thereafter, 25% of the total number of kWh of electricity sold by the utility to retail electric consumers must come from alternative energy resources, which include "advanced energy resources" such as distributed generation, clean coal, advanced nuclear, energy efficiency and fuel cell technology; and "renewable energy resources" such as solar, hydro, wind, geothermal and biomass. At least half of the 25% must be generated from renewable energy resources, including solar energy. Annual renewable energy standards began in 2009 with increases in required percentages each year through 2024. The advanced energy standard must be met by 2025 and each year thereafter. Annual targets for energy efficiency began in 2009 and require increasing energy reductions each year compared to a baseline energy usage, up to 22.3% by 2025. Peak demand reduction targets began in 2009 with increases in required percentages each year, up to 7.75% by 2018. The advanced energy and renewable energy standards have increased our power supply costs and are expected to continue to increase (and could materially increase) these costs. Pursuant to **DP&L's** approved ESP, **DP&L** is entitled to recover costs associated with its alternative energy plans, 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 has experienced and could continue to experience significant volatility and we may not be able to hedge the entire exposure of our operations from fuel availability and price volatility.

We purchase coal, natural gas and other fuel from a number of suppliers. The coal market in particular has experienced significant price volatility in the last several years. We are now in a global market for coal in which our domestic price is increasingly affected by international supply disruptions and demand balance. Coal exports from the U.S. have increased significantly at times in recent years. In addition, domestic issues like government-imposed direct costs and permitting issues that affect mining costs and supply availability, the variable demand of retail customer load and the performance of our generation fleet have an impact on our fuel procurement operations. Our approach is to hedge the fuel costs for our anticipated electric sales. However, we may not be able to hedge the entire exposure of our operations from fuel price volatility. As of the date of this report, **DPL** has substantially all of the total expected coal volume needed to meet its retail and firm wholesale sales requirements for 2011 under contract. Historically, some of our suppliers and buyers of fuel have not performed on their contracts and have failed to deliver or accept fuel as specified under their contracts. To the extent our suppliers and buyers do not meet their contractual commitments and, as a result of such failure or otherwise, we cannot secure adequate fuel or sell excess fuel in a timely or cost-effective manner or we are not hedged against price volatility, we could have a material adverse impact on our results of operations, financial condition and cash flows. In addition, **DP&L** is a co-owner of certain generation facilities where it is a non-operating owner. **DP&L** does not procure or have control over the fuel for these facilities, but is responsible for its proportionate share of the cost of fuel procured at these facilities. Co-owner operated facilities do not always have realized fuel costs that are equal to our co-owners' projections, and we are responsible for our proportionate share of any increase in actual fuel costs. Pursuant to its ESP for SSO retail customers, **DP&L** implemented a fuel and purchased power recovery mechanism beginning on January 1, 2010, which subjects our recovery of fuel and purchased power costs to tracking and adjustment on a seasonal quarterly basis. If in the future we are unable to timely or fully recover our fuel costs, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Our use of derivative and nonderivative contracts may not fully hedge our generation assets, customer supply activities, or other market positions against changes in commodity prices, and our hedging procedures may not work as planned.

We transact coal, power and other commodities to hedge our positions in these commodities. These trades are impacted by a range of factors, including variations in power demand, fluctuations in market prices, market prices for alternative commodities and optimization opportunities. We have attempted to manage our commodities price risk exposure by establishing and enforcing risk limits and risk management policies. Despite our efforts, however, these risk limits and management policies may not work as planned and fluctuating prices and other events could adversely affect our results of operations, financial condition and cash flows. As part of our risk management, we use a variety of non-derivative and derivative instruments, such as swaps, futures and forwards, to manage our market risks. We also use interest rate derivative instruments to hedge against interest rate fluctuations related to our debt. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of these contracts. We could also recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform, which could result in a material adverse effect on our results of operations, financial condition and cash flows.

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

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

We are subject to numerous environmental laws and regulations that require capital expenditures, increase our cost of operations and may expose us to environmental liabilities.

Our operations and facilities (both wholly-owned and co-owned with others) are subject to numerous and extensive federal, state and local environmental laws and regulations relating to air quality (such as reductions in NOx, SO_2 and particulate emissions), water quality, wastewater discharge, solid waste and hazardous waste. We could also become subject to additional environmental laws and regulations in the future (such as reductions in mercury and other hazardous air pollutants, SO_3 (sulfur trioxide), regulation of ash generated from coal-based generating stations and reductions in greenhouse gas emissions as discussed in more detail in the next risk factor). With respect to our largest generation station, the J.M. Stuart Station, we are also subject to continuing compliance requirements related to NOx, 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. These expenditures have been significant in the past and we expect that they could also be significant in the future. Complying with these numerous requirements could at some point become prohibitively expensive and 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 and the imposition of stricter environmental standards and controls and other injunctive measures affecting operating assets. In addition, any alleged violation of these laws, regulations and other requirements may require us to expend significant resources to defend against any such alleged violations. We own a non-controlling interest in several generating stations operated by our co-owners. As a non-controlling owner in these generating stations, we are responsible for our pro rata share of expenditures for complying with environmental laws, regulations and other requirements, but have limited control over the compliance measures taken by our co-owners. **DP&L** has an EIR in place as part of its existing rate plan structure, the last increase of which occurred in 2010 and remains at that level through 2012. In addition, **DP&L's** ESP permits it to seek recovery for costs associated with new climate change or carbon regulations. While we expect to recover certain environmental costs and expenditures from customers, if in the future we are unable to fully recover our costs in a timely manner or the SSO retail riders are by-passable or additional customer switching occurs, we could have a material adverse impact to our results of operations, financial condition and cash flows. In addition, if we were found not to be in compliance with these environmental laws, regulations or requirements, any penalties that would apply would likely not be recoverable from customers and could have a material adverse effect on our results of operations, financial condition and cash flows.

If legislation or regulations are passed at the federal or state levels imposing mandatory reductions of Greenhouse Gasses on generation facilities, we could be required to make large additional capital investments.

There is an on-going concern nationally and internationally among regulators, investors and others concerning global climate change and the contribution of emissions of GHGs, including most significantly CO_2. This concern has led to increased interest in legislation and action at the federal and state levels and litigation, including a declaration by the USEPA that GHGs pose a danger to the public health that the USEPA believes allows it to directly regulate greenhouse emissions. There have been various GHG legislative proposals introduced in Congress and there is growing consensus that some form of legislation of GHG emissions will be approved at the federal level that could result in substantial additional costs in the form of taxes or emission allowances. Approximately 99% of the energy we produce is generated by coal. If legislation or regulations are passed at the federal or state levels imposing mandatory reductions of CO_2 and other GHGs on generation facilities, we could be required to make large additional capital investments. Legislation and regulations could also impair the value of our generation stations or make some of these stations uneconomical to maintain or operate and could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing generation stations. Although **DP&L** is permitted under its current ESP to seek recovery of costs associated with new climate change or carbon regulations, our inability to fully or timely recover such costs could have a material adverse effect on our results of operations, financial condition and cash flows.

Fluctuations in our sales of coal and excess emission allowances could cause a material adverse effect on our results of operations, financial condition and cash flows for any particular period.

DP&L sells coal to other parties from time to time for reasons that include maintaining an appropriate balance between projected supply and projected use and as part of a coal 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. During 2010 and 2009, **DP&L** realized net gains from these sales. Sales of coal are impacted 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.

DP&L may sell its excess emission allowances, including NOx and SO_2 emission allowances, from time to time. Sales of any excess emission allowances are impacted by a range of factors, such as general economic conditions, fluctuations in market demand, availability of excess inventory available for sale and changes to the regulatory environment, including the status of the USEPA's CAIR. These factors could cause the amount and price of excess emission allowances we sell to fluctuate, which could cause a material adverse effect on our results of operations, financial condition and cash flows for any particular period. There has been overall reduced trading activity in the annual NOx and SO_2 emission allowance trading markets in recent years. This impact on the emission allowance trading market was due, in large part, to a court order calling into question the USEPA's CAIR annual NOx and SO_2 emission allowance trading programs and requiring the USEPA to issue new regulations to address the court order. The adoption of new regulations that could regulate emissions or establish or modify emission allowance trading programs, like the USEPA's proposed Clean Air Transport Rule to replace CAIR, could impact the emission allowance trading markets and have a material effect on **DP&L's** emission allowance sales.

The operation and performance of our facilities are subject to various events and risks that could negatively impact our business.

The operation and performance of our generation, transmission and distribution facilities and equipment is subject to various events and risks, such as the potential breakdown or failure of equipment, processes or facilities, fuel supply or transportation disruptions, the loss of cost-effective disposal options for solid waste generated by our facilities (such as coal ash and gypsum), accidents, injuries, labor disputes or work stoppages by employees, operator error, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, performance below expected or required levels, weather-related and other natural disruptions, vandalism, events occurring on the systems of third parties that interconnect to and affect our system and the increased maintenance requirements, costs and risks associated with our aging generation units. Our results of operations, financial condition and cash flows could have a material adverse impact due to the occurrence or continuation of these events. Diminished availability or performance of our transmission and distribution facilities could result in reduced customer satisfaction and regulatory inquiries and fines, which could have a material adverse effect on our results of operations, financial condition and cash flows. Operation of our owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and efficiency levels and likely result in lost revenues and increased expenses that could have a material adverse effect on our results of operations, financial condition and cash flows. In particular, since over 50% of our base-load generation is derived from co-owned generation stations operated by our co-owners, poor operational performance by our co-owners, misalignment of co-owners' interests or lack of control over costs (such as fuel costs) incurred at these stations could have an adverse effect on us. We have constructed and placed into service FGD facilities at most of our base-load generating stations. If there is significant operational failure of the FGD equipment at the generating stations, we may not be able to meet emission requirements at some of our generating stations or, at other stations, it may require us to burn more expensive cleaner coal or utilize emission allowances. These events could result in a substantial increase in our operating costs. Depending on the degree, nature, extent, or willfulness of any failure to comply with environmental requirements, including those imposed by the Consent Decree, such non-compliance could result in the imposition of penalties or the shutting down of the affected generating stations, which could have a material adverse effect on our results of operations, financial condition and cash flows.

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

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

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

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

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

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

On October 1, 2004, in compliance with Ohio law, **DP&L** turned over control of its transmission functions and fully integrated into PJM, a regional transmission organization. The price at which we can sell our generation capacity and energy is now dependent on a number of factors, which include the overall supply and demand of generation and load, other state legislation or regulation, transmission congestion, and PJM's business rules. While we can continue to make bilateral transactions to sell our generation through a willing-buyer and willing-seller relationship, any transactions that are not pre-arranged are subject to market conditions at PJM. To the extent we sell electricity into the power markets on a contractual basis, we are not guaranteed any rate of return on our capital investments through mandated rates. The PJM RPM base residual auction for the 2013/2014 and 2012/2013 periods cleared at a per megawatt price of $28/day and $16/day, respectively, for our RTO area. Prior to these auctions, the per megawatt prices for the 2011/2012 and 2010/2011 periods were $110/day and $174/day, respectively. The results of the PJM RPM base residual auction are impacted by the supply and demand of generation and load and also may be impacted by congestion and PJM rules relating to bidding for Demand Response and Energy Efficiency resources. 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 if the auction prices are sustained at low levels, our results of operations, financial condition and cash flows could have a material adverse impact.

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. While PJM transmission rates were initially designed to be revenue neutral, various proposals and proceedings currently taking place at 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 impact 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 deferral and recovery of RTO related charges. Therefore, most if not all of the above costs are currently being recovered through our SSO retail rates. If in the future, however, we are unable to defer or recover all of these cost in a timely manner, or the SSO retail riders are by-passable or additional customer switching occurs, our results of operations, financial condition and cash flows could have a material adverse impact.

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

Costs associated with new transmission projects could have a material adverse effect on our results of operations, financial condition and cash flows.

Annually, PJM performs a review of the capital additions required to provide reliable electric transmission services throughout its territory. PJM traditionally allocated the costs of constructing these facilities to those entities that benefited directly from the additions. FERC orders issued in 2007 and thereafter modified the traditional method of allocating costs associated with new high voltage planned transmission facilities. FERC ordered that the cost of new high-voltage facilities be socialized across the PJM region. Various parties, including **DP&L**, challenged this allocation method and in 2009, the U.S. Court of Appeals, Seventh Circuit ruled that the FERC had failed to provide a reasoned basis for the allocation method and remanded the case to the FERC for further proceedings. Until such time as FERC may act to approve a change in methodology, PJM will continue to apply the allocation methodology that had been approved by FERC in 2007. The overall impact of FERC's allocation methodology cannot be definitively assessed because not all new planned construction is likely to happen. The additional costs charged to **DP&L** for new large transmission approved projects were immaterial in 2010 and are not expected to be material in 2011. Over time, as more new transmission projects are constructed and if the allocation method is not changed, the annual costs could become material. Although we continue to maintain that the costs of these projects should be borne by the direct beneficiaries of the projects and that **DP&L** is not one of these beneficiaries, **DP&L** can, and currently is recovering these allocated costs from its SSO retail customers through the TCRR rider.

Our inability to obtain financing on reasonable terms, or at all, with creditworthy counterparties could adversely affect our results of operations, financial condition and cash flows.

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

Poor investment performance of our benefit plan assets and other factors impacting benefit plan costs could unfavorably impact our liquidity and results of operations.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under our pension and postretirement 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 postretirement benefit plan assets will increase the funding requirements under our pension and postretirement benefit plans if the actual asset returns do not recover these declines in value in the foreseeable future. Future pension funding requirements, and the timing of funding payments, may also be subject to changes in legislation. The Pension Protection Act, enacted in August 2006, requires underfunded pension plans to improve their funding ratios within prescribed intervals based on the level of their underfunding. As a result, our required contributions to these plans at times have increased and may increase in the future. In addition, our pension and postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the discounted liabilities increase, potentially increasing 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 postretirement benefit plans. Declines in market values and increased funding requirements could have a material adverse effect on our results of operations, financial condition and cash flows.

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

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

Our stock price may fluctuate on account of a number of factors, many of which are beyond our control.

The market price of **DPL's** common stock has fluctuated over a relatively wide range. Over the past three years, the market price of our common stock has fluctuated with a low of $19.16 and a high of $30.18. Our common stock in recent years has experienced significant price and volume variations that have often been unrelated to our operating performance. Over the previous year, the global markets have increasingly been characterized by substantially increased volatility in companies in a number of industries and in the broader markets. The market price of our common stock may continue to significantly fluctuate in the future and may be affected adversely by factors such as actual or anticipated change in our operating results, acquisition activity, changes in financial estimates by securities analysts, general market conditions, rumors and other factors, which factors may increase price volatility and be exacerbated by continued disruption in the global markets at large.

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

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

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

The exercise of warrants would increase the number of common shares outstanding and increase our common share dividend costs, thus affecting any existing guidance on earnings per share and adversely affecting our financial condition and cash flows.

DPL's warrant holders can exercise their warrants to purchase shares of **DPL** common stock at their discretion until March 12, 2012. As of the date of this report, the number of outstanding warrants is 1.7 million. As a result, **DPL** could be required to issue up to 1.7 million common shares in exchange for the receipt of the exercise price of $21.00 per share or pursuant to a cashless exercise process. The exercise of warrants would increase the number of common shares outstanding and increase our common share dividend payments.

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

Our internal controls, accounting policies and practices and internal information systems are designed to enable us to capture and process transactions and information in a timely and accurate manner in compliance with GAAP in the United States of America, laws and regulations, taxation requirements and federal securities laws and regulations in order to, among other things, disclose and report financial and other information in connection with the recovery of our costs and with our reporting requirements under federal securities, tax and other laws and regulations and to properly process payments. We have implemented corporate governance, internal control and accounting policies and procedures in connection with the Sarbanes-Oxley Act of 2002 (the "Act"). Our internal controls and policies have been and continue to be closely monitored by management and our Board of Directors to ensure continued compliance with Section 404 of the Act. 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 impact 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 impact how we report our results of operations, financial condition and cash flows. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial condition. In addition, in preparing our Consolidated Financial Statements, management is required to make estimates and assumptions. Actual results could differ significantly from those estimates.

The SEC has issued a roadmap for the transition by U.S. public companies to the use of International Financial Reporting Standards (IFRS) promulgated by the International Accounting Standards Board that could result in significant changes to our accounting and reporting, such as in the treatment of regulatory assets and liabilities and property. Under the SEC's proposed roadmap, we could be required to prepare financial statements in accordance with IFRS in 2015. The SEC expects to make a determination in 2011 regarding the mandatory adoption of IFRS. We are currently assessing the impact that this potential change would have on our Consolidated Financial Statements and we will continue to monitor the development of the potential implementation of IFRS.

If we are unable to maintain a qualified and properly motivated workforce, our results of operations, financial condition and cash flows could have a material adverse effect.

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 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, our results of operations, financial condition and cash flows could have a material adverse impact. In addition, we have employee compensation plans that reward the performance of our employees. While we seek to ensure that our compensation plans encourage acceptable levels for risk and high performance through pay mix, performance metrics and timing, and although we have policies and procedures in place to mitigate excessive risk-taking by employees; excessive risk-taking by our employees to achieve performance targets could result in events that could have a material adverse effect on our results of operations, financial condition and cash flows.

We are subject to collective bargaining agreements and other employee workforce factors that could affect our businesses.

Over half of our employees are represented by a collective bargaining agreement that is in effect until October 31, 2011. 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 bargaining agreement or at the expiration of the collective bargaining agreement before a new agreement is negotiated. Work stoppages by, or poor relations or ineffective negotiations with, our employees could have a material adverse effect on our results of operations, financial condition and cash flows.

Potential security breaches and terrorism could adversely affect our business.

Man-made problems, such as human error, computer viruses, terrorism, theft and sabotage, may disrupt our operations and harm our operating results. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In the course of our business, we also store and use certain of our customers', employees' and others' personal information and other confidential and sensitive information. Despite our implementation of security measures, all of our technology systems are vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover them in a timely way, we could be unable to fulfill critical business functions and 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. These events could have a material adverse effect on our results of operations, financial condition and cash flows. Our third party service providers that provide critical business functions or have access to sensitive and confidential information and other data may also be vulnerable to security breaches and other man-made problems that could have an adverse effect on us. In addition, our generation plants, fuel storage facilities, transmission and distribution facilities may be targets of terrorist activities that could disrupt our business. Any such disruption could result in a material decrease in revenues and significant additional costs to repair and insure our assets, which could have a material adverse effect on our results of operations, financial condition and cash flows. The continued threat of terrorism and heightened security and military action in response to this threat, or any future acts of terrorism, may cause further disruptions to the economies of the United States and other countries and create further uncertainties or otherwise materially harm our results of operations, financial condition and cash flows.

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

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

Item 1B — Unresolved Staff Comments

None

Item 2 — Properties

Information relating to our properties is contained in Item 1 — ELECTRIC OPERATIONS AND FUEL SUPPLY and Note 4 of Notes to Consolidated Financial Statements.

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

Item 3 - Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We are also from time to time involved in other reviews, investigations and proceedings by governmental and regulatory agencies regarding our business, certain of which may result in adverse judgments, settlements, fines, penalties, injunctions or other relief. We believe the amounts provided in our Consolidated Financial Statements, as prescribed by GAAP, for these matters are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters (including those matters noted below) and to comply with applicable laws and regulations will not exceed the amounts reflected in our Consolidated Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2010, cannot be reasonably determined.

As we have previously disclosed, on or about June 24, 2004, the SEC commenced a formal investigation into the issues raised by a memorandum that had been sent on March 10, 2004, by **DPL's** and **DP&L's** Corporate Controller at the time to the Chairman of the Audit Committee of our Board of Directors expressing the Corporate Controller's "concerns, perspectives and viewpoints" regarding financial reporting and governance issues within **DPL** and **DP&L**. On May 7, 2010, **DPL** received confirmation from the SEC's Division of Enforcement that it had completed its investigation as to **DPL** and did not intend to recommend any action at this time.

The following additional information is incorporated by reference into this Item: (i) information about the legal and other proceedings contained in Item 1 — COMPETITION AND REGULATION of Part 1 of this Annual Report on Form 10-K under the subheading "Ohio Retail Rates" and (ii) information about the legal proceedings contained in Item 8 — Note 16 of Notes to Consolidated Financial Statements of Part II of this Annual Report on Form 10-K under the subheadings "Litigation Involving Co-Owned Plants", "Notices of Violation Involving Co-Owned Plants" and "Notices of Violation Involving Wholly-Owned Plants" of the section entitled Litigation, Notices of Violation and Other Matters Related to Air Quality and under the subheading "Regulation of Waste Disposal" under the sections entitled Regulation Matters Related to "Land Use and Solid Waste Disposal."

Item 4 — Removed and Reserved

PART II

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

As of February 15, 2011, there were 19,792 holders of record of **DPL** common equity, excluding individual participants in security position listings. The following table presents the high and low per share sales prices for **DPL** common stock as reported by the New York Stock Exchange for each quarter of 2010 and 2009:

	2010		2009	
	High	Low	High	Low
First Quarter	$ **28.47**	$ **26.51**	$ 23.28	$ 19.27
Second Quarter	$ **28.18**	$ **23.80**	$ 23.46	$ 21.18
Third Quarter	$ **26.65**	$ **23.95**	$ 26.53	$ 22.79
Fourth Quarter	$ **27.51**	$ **25.33**	$ 28.68	$ 25.16

DP&L's common stock is held solely by **DPL** and, as a result, is not listed for trading on any stock exchange.

As long as **DP&L** preferred stock is outstanding, **DP&L's** Amended Articles of Incorporation contain provisions restricting the payment of cash dividends on any of its common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds the net income of **DP&L** available for dividends on its Common Stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not impacted **DP&L's** ability to pay cash dividends and, as of December 31, 2010, **DP&L's** retained earnings of $616.9 million were all available for **DP&L** common stock dividends payable to **DPL.**

DPL paid regular quarterly cash dividends of $0.3025 and $0.2850 per share on our common stock during 2010 and 2009, respectively. The annualized dividend rate was $1.21 per share in 2010 and $1.14 per share in 2009.

On December 8, 2010, **DPL's** Board of Directors authorized a quarterly dividend rate increase of approximately 10%, increasing the quarterly dividend per **DPL** common share from $0.3025 to $0.3325, effective with the next dividend declaration. If this dividend rate were maintained, the annualized dividend would increase from $1.21 per share to $1.33 per share. Additional information concerning dividends paid on **DPL** common stock is set forth under Selected Quarterly Information in Item 8 — Financial Statements and Supplementary Data.

Information regarding **DPL's** equity compensation plans as of December 31, 2010 is disclosed in Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, which incorporates such information by reference from **DPL's** proxy statement for the 2011 Annual Meeting of Shareholders.

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The following table details the repurchase by **DPL** of its common shares during the fourth quarter of 2010:

Month (1)	Number of shares purchased (2)	Average price paid per share (3)	Number of shares purchased as part of the Stock Repurchase Program (4)	Approximate dollar value of shares that could still be purchased under the program (4)
October	—	$ —	—	$ 200,000,000
November	1,094,995	$ 25.94	1,094,995	$ 171,595,830
December	945,335	$ 25.60	941,841	$ 147,484,700
	2,040,330		2,036,836	

(1) Based on a calendar month.

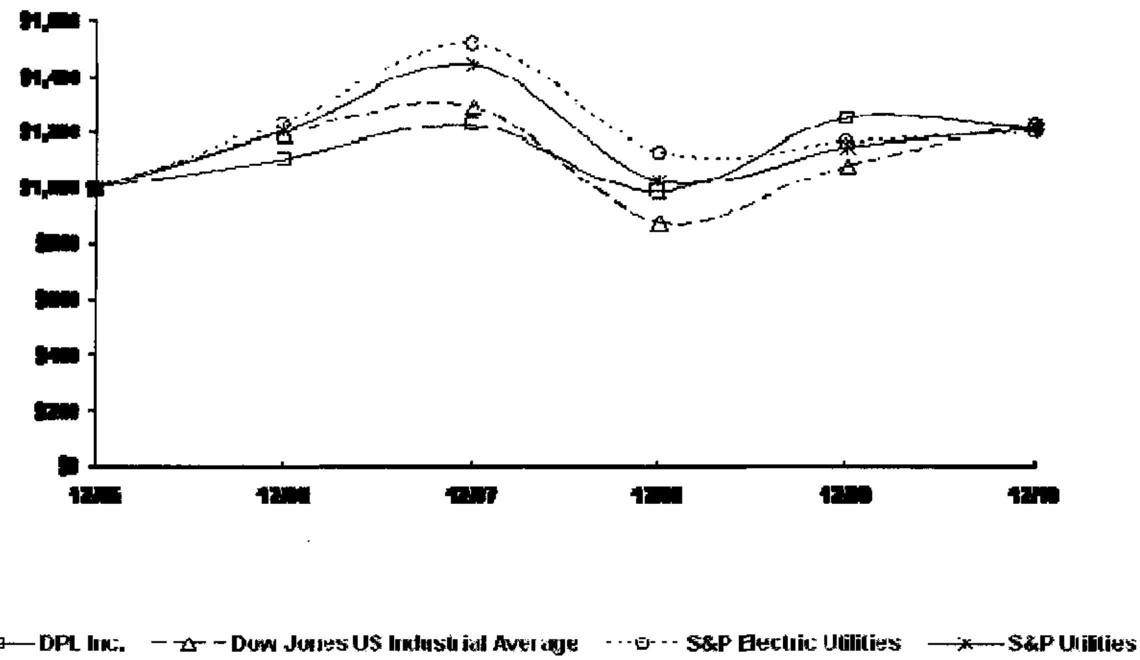
*(2) Comprises shares purchased as part of **DPL**'s 2010 repurchase program and shares surrendered to **DPL** by employees to satisfy individual tax withholding obligations upon vesting of equity awards that are settled in **DPL** common stock. Shares totaling 3,494 were surrendered during the fourth quarter of 2010 to satisfy these individual tax withholding obligations.*

*(3) Average price paid per share reflects the individual trade price of repurchases under **DPL**'s current repurchase program as well as the closing price of **DPL** common stock on the vesting dates of the equity awards.*

*(4) On October 27, 2010, the **DPL** Board of Directors approved a Stock Repurchase Program under which **DPL** may repurchase up to $200 million of its common stock from time to time in the open market, through private transactions or otherwise. During the fourth quarter of 2010, **DPL** repurchased approximately 2.04 million shares of its common stock at an average price per share of $25.75. This Stock Repurchase Program will run through December 31, 2013 but may be modified or terminated at any time without notice.*

The graph below matches **DPL's** cumulative 5-year total shareholder return on common stock with the cumulative total returns of the Dow Jones US Industrial Average index, the S&P Utilities index and the S&P Electric Utilities index. The graph tracks the performance of a $1,000 investment in our common stock and in each index (with the reinvestment of all dividends) from December 31, 2005 to December 31, 2010.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among DPL Inc., The Dow Jones US Industrial Average Index, The S&P Electric Utilities Index And The S&P Utilities Index



***$1000 invested on 12/31/05 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.**

	12/05	12/06	12/07	12/08	12/09	12/10
DPL Inc.	$ 1,000.00	$ 1,108.68	$ 1,226.29	$ 987.60	$ 1,252.18	$ 1,220.96
Dow Jones US Industrial Average	$ 1,000.00	$ 1,190.47	$ 1,296.24	$ 882.34	$ 1,082.48	$ 1,234.72
S&P Electric Utilities	$ 1,000.00	$ 1,232.11	$ 1,516.95	$ 1,125.05	$ 1,163.05	$ 1,202.99
S&P Utilities	$ 1,000.00	$ 1,209.90	$ 1,444.37	$ 1,025.78	$ 1,147.94	$ 1,210.62

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Item 6 - Selected Financial Data

($ in millions except per share amounts or as indicated)	2010	2009	2008	2007	2006
	For the years ended December 31,				
DPL					
Basic earnings per share of common stock:					
Continuing operations (a)	$ 2.51	$ 2.03	$ 2.22	$ 1.97	$ 1.12
Discontinued operations (b) (c)	$ —	$ —	$ —	$ 0.09	$ 0.12
Total basic earnings per common share	$ 2.51	$ 2.03	$ 2.22	$ 2.06	$ 1.24
Diluted earnings per share of common stock:					
Continuing operations (a)	$ 2.50	$ 2.01	$ 2.12	$ 1.80	$ 1.03
Discontinued operations (b) (c)	$ —	$ —	$ —	$ 0.08	$ 0.12
Total dilutive earnings per common share	$ 2.50	$ 2.01	$ 2.12	$ 1.88	$ 1.15
Dividends declared per share	$ 1.21	$ 1.14	$ 1.10	$ 1.04	$ 1.00
Dividend payout ratio	48.2%	56.2%	49.5%	50.5%	80.7%
Total electric sales (millions of kWh)	17,237	16,667	17,172	18,598	18,418
Results of operations:					
Revenues	$ 1,883.1	$ 1,588.9	$ 1,601.6	$ 1,515.7	$ 1,393.5
Earnings from continuing operations, net of tax (a)	$ 290.3	$ 229.1	$ 244.5	$ 211.8	$ 125.6
Earnings from discontinued operations, net of tax	$ —	$ —	$ —	$ 10.0	$ 14.0
Cumulative effect of accounting change, net of tax	$ —	$ —	$ —	$ —	$ —
Net income	$ 290.3	$ 229.1	$ 244.5	$ 221.8	$ 139.6
Financial position items at December 31:					
Total assets	$ 3,813.3	$ 3,641.7	$ 3,637.0	$ 3,566.6	$ 3,612.2
Long-term debt (d)	$ 1,026.6	$ 1,223.5	$ 1,376.1	$ 1,541.5	$ 1,551.8
Total construction additions	$ 151.4	$ 145.3	$ 227.8	$ 346.7	$ 351.6
Redeemable preferred stock of subsidiary	$ 22.9	$ 22.9	$ 22.9	$ 22.9	$ 22.9
Senior unsecured debt ratings at December 31:					
Fitch Ratings	A-	A-	BBB+	BBB+	BBB
Moody's Investors Service	Baa1	Baa1	Baa2	Baa2	Baa3
Standard & Poor's Corporation	BBB+	BBB+	BBB-	BBB-	BB
Number of shareholders - common stock	19,877	20,888	21,628	22,771	24,434
DP&L					
Total electric sales (millions of kWh)	17,083	16,590	17,105	18,598	18,418
Results of operations:					
Revenues	$ 1,790.5	$ 1,550.4	$ 1,572.9	$ 1,507.4	$ 1,385.2
Earnings on common stock (a)	$ 276.8	$ 258.0	$ 284.9	$ 270.7	$ 241.6
Financial position items at December 31:					
Total assets	$ 3,475.4	$ 3,457.4	$ 3,397.7	$ 3,276.7	$ 3,090.3
Long-term debt (d)	$ 884.0	$ 783.7	$ 884.0	$ 874.6	$ 785.2
Redeemable preferred stock	$ 22.9	$ 22.9	$ 22.9	$ 22.9	$ 22.9
Senior secured debt ratings at December 31:					
Fitch Ratings	AA-	AA-	A+	A+	A
Moody's Investors Service	Aa3	Aa3	A2	A2	A3
Standard & Poor's Corporation	A	A	A-	BBB+	BBB
Number of shareholders - preferred stock	234	242	256	281	290

(a) *In the fourth quarter of 2006, **DPL** entered into agreements to sell two of its peaking facilities resulting in a $44.2 million ($71 million pre-tax) impairment charge. The sale was finalized in April 2007. During 2006, **DPL** recorded a $37.3 million ($61.2 million pre-tax) charge for early redemption of debt. **DP&L** recorded a $2.5 million ($4.1 million pre-tax) charge for early redemption of debt in 2006. In May 2007, **DPL** settled the litigation with former executives resulting in a $19.7 million ($31 million pre-tax) gain. In April 2007, **DPL*** *also recouped legal costs associated with the litigation with the former executives from one of its insurers resulting in a $9.2 million ($14.5 million pre-tax) gain. In 2008,* ***DPL*** *sold coal and excess emission allowances to various counterparties, realizing net gains of $58.2 million ($83.4 million pre-tax) and $24.3 million ($34.8 million pre-tax), respectively. Also, in June 2008,* ***DPL*** *entered into a $42 million tax settlement with ODT resulting in a recorded income tax benefit of $8.5 million.*

(b) *On February 13, 2005,* ***DPL's*** *subsidiaries, MVE, Inc. (MVE) and MVIC, entered into an agreement to sell their respective interest in forty-six private equity funds. MVE and MVIC completed the sale of forty-three funds and a portion of another during 2005. The ownership interests to the remaining two funds and a portion of the third fund were transferred in 2006 and 2007, at which time* ***DPL*** *recognized previously deferred gains. $7.9 million ($4.9 million after tax) and $18.9 million ($12.1 million after tax) of these previously deferred gains were recognized in 2007 and 2006, respectively.*

(c) *On May 21, 2007* ***DPL*** *settled litigation with three former executives, the three former executives relinquished all of their rights to certain deferred compensation, restricted stock units, MVE incentives, stock options and reimbursement of legal fees. The reversal of accruals related to the performance of the financial asset portfolio was recorded in discontinued operations. A portion of the $25 million settlement expense was allocated to discontinued operations. These transactions resulted in a net gain of $8.1 million, net of associated expenses ($5.1 million after tax), on the settlement of litigation being recorded in discontinued operations in 2007.*

(d) *Excludes current maturities of long-term debt.*

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

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

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

Forward-looking statements speak only as of the date of the document in which they are made. We disclaim any obligation or undertaking to provide any updates or revisions to any forward-looking statement to reflect any change in our expectations or any change in events, conditions or circumstances on which the forward-looking statement is based.

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

BUSINESS OVERVIEW

DPL is a regional electric energy and utility company. During 2010, **DPL**, for the first time, met the GAAP requirements for separate segment reporting. **DPL's** two segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary. Refer to Note 17 of Notes to Consolidated Financial Statements for more information relating to these reportable segments. **DP&L** does not have any reportable segments.

DP&L is primarily engaged in the generation, transmission and distribution of electricity in West Central Ohio. **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.

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We operate and manage generation assets and are exposed to a number of risks. These risks include, but are not limited to, electricity wholesale price risk, PJM capacity price risk, regulatory risk, environmental risk, fuel supply and price risk, customer switching risk and the risk associated with power plant 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 power plants 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.

We have identified certain issues that we believe may have a significant impact on our results of operations and financial condition in the future. The following issues mentioned below are not meant to be exhaustive but to provide insight on matters that are likely to have an effect on our results of operations and financial condition in the future:

REGULATORY ENVIRONMENT

- **Carbon Emissions — Climate Change Legislation**

  There is an on-going concern nationally and internationally about global climate change and the contribution of emissions of GHGs, including most significantly, CO_2. This concern has led to interest in legislation at the federal level, actions at the state level as well as litigation relating to GHG emissions. In 2007, a U.S. Supreme Court decision upheld that the USEPA has the authority to regulate CO_2 emissions from motor vehicles under the CAA. In April 2009, the USEPA issued a proposed endangerment finding under the CAA, which was finalized and published on December 15, 2009. The proposed finding determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. In December 2009, USEPA finalized this endangerment finding with a regulatory effective date of January 2010. Numerous affected parties have asked the USEPA Administrator to reconsider this decision. This endangerment finding, if not changed, is expected to lead to the regulation of CO_2 and other GHGs from electric generating units and other stationary sources of these emissions. Increased pressure for CO_2 emissions reduction is also coming from investor organizations and the international community. Environmental advocacy groups are also focusing considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. Legislation proposed in 2009 to target a reduction in the emission of GHGs from large sources was not enacted. Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 16 million tons annually. If legislation or regulations are passed at the federal or state levels that impose mandatory reductions of CO_2 and other GHGs on generation facilities, the cost to **DPL** and **DP&L** of such reductions could be material.

- **SB 221 Requirements**

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

  SB 221 also contains provisions for determining whether an electric utility has significantly excessive earnings. On September 9, 2009, the PUCO issued an order establishing a significantly excessive earnings test (SEET) proceeding. After receiving comments from interested parties including **DP&L**, the PUCO issued an order on June 30, 2010 to establish general rules for calculating the earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings. Pursuant to the ESP Stipulation, **DP&L** becomes subject to the SEET in 2013 based on 2012 earnings results and the SEET may have a material impact on operations. **DP&L** faces regulatory uncertainty from its next ESP or MRO filing which is scheduled to be filed in the first quarter of 2012 to be effective January 1, 2013. The filing may result in changes to the current rate structure and riders.

- **NOx and SO_2 Emissions — CAIR**

  The USEPA issued CAIR on March 10, 2005 to regulate certain upwind states with respect to fine particulate matter and ozone. CAIR created interstate trading programs for annual NOx emission allowances and made modifications to an existing trading program for SO_2 that were to take effect in 2010. On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit issued a decision that vacated the USEPA CAIR and its associated Federal Implementation Plan. This decision remanded these issues back to the USEPA. The court's decision, in part, invalidated the new NOx annual emission allowance trading program and the modifications to the SO_2 emission trading program, and created uncertainty regarding future NOx and SO_2 emission reduction requirements and their timing. On December 23, 2008, the court reversed part of its decision that vacated CAIR. Thus, CAIR currently remains in effect, but the USEPA remains subject to the court's order to revise the program. On July 6, 2010, the USEPA proposed the Clean Air Transport Rule (CATR) which will effectively replace CAIR. We have reviewed this proposal and submitted comments to the USEPA on September 30, 2010. At this time, we are unable to determine the overall financial impact that these rules could have on our operations in the future.

- **Dodd-Frank Financial Reform Bill**

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

COMPETITION AND PJM PRICING

- **RPM Capacity Auction Price**

  The PJM RPM capacity base residual auction for the 2013/2014 period cleared at a per megawatt price of $28/day for our RTO area. The per megawatt prices for the periods 2012/2013, 2011/2012 and 2010/2011 were $16/day, $110/day and $174/day, respectively, based on previous auctions. Future RPM auction results will be dependent not only on the overall supply and demand of generation and load, but may also be impacted by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions. The SSO retail costs and revenues are included in the RPM rider therefore increases in customer switching causes more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. We cannot predict the outcome of future auctions or customer switching but based on actual results attained in 2010, we estimate that a hypothetical increase or decrease of $10 in the capacity auction price would result in an annual impact to net income of approximately $4.4 million and $3.1 million for **DPL** and **DP&L**, respectively. These estimates do not, however, take into consideration the other factors that may affect the impact of capacity revenues and costs on net income such as the levels of customer switching, our generation capacity, the levels of wholesale revenues and our retail customer load. These estimates are discussed further within Commodity Pricing Risk under the Market Risk section of this Management Discussion & Analysis.

- **Ohio Competitive Considerations and Proceedings**

  Since January 2001, **DP&L's** electric customers have been permitted to choose their retail electric generation supplier. **DP&L** continues to have the exclusive right to provide delivery service in its state certified territory and the obligation to supply retail generation service to customers that do not choose an alternative supplier. The PUCO maintains jurisdiction over **DP&L's** delivery of electricity, SSO and other retail electric services. Overall power market prices, as well as government aggregation initiatives within **DP&L's** service territory, have led or may lead to the entrance of additional competitors in our service territory. During the year ended December 31, 2010, there were four additional unaffiliated marketers that registered as CRES providers in **DP&L's** service territory, bringing the total number of CRES providers in **DP&L's** service territory to eleven. DPLER, an affiliated company and one of the eleven registered CRES providers, has been marketing transmission and generation services to **DP&L** customers. During 2010, DPLER accounted for approximately 4,417 million kWh of the total 4,562 million kWh supplied by CRES providers within **DP&L's** service territory. During 2010, 847 customers with an annual energy usage of 145 million kWh were supplied by other CRES providers within **DP&L's** service territory, compared to 44 customers that had an annual energy usage of 16 million kWh during 2009. The volume supplied by DPLER represents approximately 31% of **DP&L's** total distribution sales volume during 2010. The reduction to gross margin in 2010 as a result of customers switching to DPLER and other CRES providers was approximately $17 million and $53 million, for **DPL** and **DP&L**, respectively. We currently cannot determine the extent to which customer switching to CRES providers will occur in the future and the impact this will have on our operations, but any additional switching could have a significant adverse effect on our future results of operations, financial condition and cash flows.

FUEL AND RELATED COSTS

- **Fuel and Commodity Prices**

  The coal market is a global market in which domestic prices are affected by international supply disruptions and demand balance. In addition, domestic issues like government-imposed direct costs and permitting issues are affecting mining costs and supply availability. Our approach is to hedge the fuel costs for our anticipated electric sales. For the year ending December 31, 2011, we have hedged substantially all our coal requirements to meet our committed sales. We may not be able to hedge the entire exposure of our operations from commodity price volatility. If our suppliers do not meet their contractual commitments or we are not hedged against price volatility and we are unable to recover costs through the fuel and purchased power recovery rider, our results of operations, financial condition or cash flows could be materially affected.

  Effective January 2010, the SSO retail customers' portion of fuel price changes, including coal requirements and purchased power costs, was reflected in the implementation of the fuel and purchased power recovery rider, subject to PUCO review. **DP&L** is currently undergoing an audit of its fuel and purchased power recovery rider and as a result there is some uncertainty as to the costs that will be approved for recovery. Independent third parties conduct the fuel audit in accordance with the PUCO standards. **DP&L** anticipates that some of this uncertainty will be resolved during the summer of 2011 after completion of the fuel audit. Based on the results of the audit, **DP&L** may record a favorable or unfavorable adjustment to earnings. It is too early to determine if any such adjustment would be material to our results of operations, financial condition and cash flows.

- **Sales of Coal and Excess Emission Allowances**

  During the year ended December 31, 2010, **DP&L** sold coal and excess emission allowances to various counterparties realizing total net gains of $4.1 million and $0.8 million, respectively, compared to total net gains of $56.3 million and $5.0 million, respectively, realized over the same period in 2009. For 2010, these gains are recorded as a component of **DP&L's** fuel costs and are reflected in operating income. Coal sales are impacted by a range of factors but can be largely attributed to the following: price volatility among the different coal basins or the quality of coal based on market conditions (coal optimization), variation in power demand, and the market price of power compared to the cost to produce power. Sales of excess emission allowances are impacted, among other factors, by: general economic conditions; fluctuations in market demand and pricing; availability of excess inventory available for sale; and changes to the regulatory environment in which we operate. The combined impact of these factors on our ability to sell coal and emission allowances in 2011 and beyond is not fully known at this time and could materially impact the amount of gains that will be recognized in the future. Effective January 2010, as part of the operation of the fuel and purchased power recovery rider, the SSO retail customers' share of the emission gains and a portion of the SSO retail customers' share of the coal gains were used to reduce the overall rate charged to customers.

FINANCIAL OVERVIEW

The following financial overview relates to **DPL**, which includes its principal subsidiary **DP&L**. The results of operations for both **DPL** and **DP&L** are separately discussed in more detail following this financial overview.

For the year ended December 31, 2010, Net income for **DPL** was $290.3 million, or $2.50 per share, compared to Net income of $229.1 million, or $2.01 per share, for the same period in 2009. All EPS amounts are on a diluted share basis. The increase in net income compared to the prior year was primarily due to the following:

- an increase in retail rates primarily as a result of an increase in the EIR, TCRR and RPM riders combined with the implementation of the fuel and energy efficiency riders,
- an increase in sales volumes due to favorable weather and improved economic conditions,
- a decrease in the volume of fuel consumed due to decreased generation by our power plants,
- a net reduction in interest costs primarily as a result of certain redemptions of outstanding debt, and
- an increase in wholesale market prices.

Partially offsetting these items were:

- an increase in purchased power prices,
- a decrease in retail revenue due to pricing associated with competitively supplied customers,
- an increase in RTO capacity and other charges, net of RTO revenues, which includes the net impact of the deferral and recovery of costs under the TCRR and RPM riders,
- an overall decline in generating plant performance which resulted in a decrease in wholesale sales volume,
- a decrease in gains recognized from the sales of coal and excess emission allowances, and
- an increase in long-term disability and other operation and maintenance expenses.

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. DP&L** provides approximately 93% of **DPL's** total consolidated gross margin. 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

	For the years ended December 31,		
$ in millions	2010	2009	2008
Revenues:			
Retail	$ 1,456.5	$ 1,229.0	$ 1,223.3
Wholesale	142.3	122.5	149.9
RTO revenues	86.6	89.4	110.4
RTO capacity revenues	186.2	136.3	106.9
Other revenues	11.5	11.7	11.1
Total revenues	$ 1,883.1	$ 1,588.9	$ 1,601.6
Cost of revenues:			
Fuel costs	$ 388.8	$ 391.7	$ 361.2
Gains from sale of coal	(4.1)	(56.3)	(83.4)
Gains from sale of emission allowances	(0.8)	(5.0)	(34.8)
Net fuel	383.9	330.4	243.0
Purchased power	82.1	46.9	148.7
RTO charges	113.4	100.9	127.8
RTO capacity charges	191.9	112.4	100.9
Net purchased power	387.4	260.2	377.4
Total cost of revenues	$ 771.3	$ 590.6	$ 620.4
Gross margins (a)	$ 1,111.8	$ 998.3	$ 981.2
Gross margin as a percentage of revenues	59.0%	62.8%	61.3%
Operating income	$ 504.4	$ 428.2	$ 435.5
Earnings per share of common stock:			
Basic EPS from operations	$ 2.51	$ 2.03	$ 2.22
Diluted EPS from operations	2.50	2.01	2.12

(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.

Revenues

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

Number of days	For the years ended December 31, 2010	2009	2008
Heating degree days (a)	**5,636**	5,561	5,811
Cooling degree days (a)	**1,245**	734	853

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

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

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

$ in millions	2010 vs. 2009	2009 vs. 2008
Retail		
Rate	$ **148.0**	$ 119.6
Volume	**78.4**	(113.5)
Other	**1.1**	(0.4)
Total retail change	**$ 227.5**	$ 5.7
Wholesale		
Rate	$ **31.5**	$ (87.0)
Volume	**(11.7)**	59.6
Total wholesale change	**$ 19.8**	$ (27.4)
RTO capacity and other		
RTO capacity and other revenues	**$ 46.9**	$ 9.0
Total revenues change	**$ 294.2**	$ (12.7)

For the year ended December 31, 2010, Revenues increased $294.2 million, or 19%, to $1,883.1 million from $1,588.9 million in the same period of the prior year. This increase was primarily the result of higher average retail and wholesale rates, higher retail sales volume, and increased RTO capacity and other revenues, partially offset by lower wholesale sales volume. The revenue components for the year ended December 31, 2010 are further discussed below:

- Retail revenues increased $227.5 million resulting primarily from an 11% increase in average retail rates due largely to the implementation of the fuel and energy efficiency riders, an increase in the TCRR and RPM riders, combined with the incremental effect of the recovery of costs under the EIR. This increase in the average retail rates was partially offset by the effect of lower rates due to customer switching which has resulted from increased levels of competition to provide transmission and generation services in our service territory. Retail sales volume had a 6% increase compared to those in the prior year period largely due to more favorable weather and improved economic conditions. The favorable weather conditions resulted in a 70% increase in the number of cooling degree days to 1,245 days from 734 days in 2009. The above resulted in a favorable $148.0 million retail price variance and a favorable $78.4 million retail sales volume variance.
- Wholesale revenues increased $19.8 million primarily as a result of a 28% increase in wholesale average prices, partially offset by a 10% decrease in wholesale sales volume which was largely a result of lower generation by our power plants and increased retail sales volume. This resulted in a favorable $31.5 million wholesale price variance partially offset by an unfavorable wholesale sales volume variance of $11.7 million.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, increased $46.9 million compared to the same period in 2009. This increase in RTO capacity and other revenues was primarily the result of a $49.9 million increase in revenues realized from the PJM capacity auction, partially offset by a $3.0 million decrease in transmission, congestion and other revenues.

For the year ended December 31, 2009, Revenues decreased $12.7 million, or 1%, to $1,588.9 million from $1,601.6 million in the prior year. This decrease was primarily the result of lower retail sales volume as well as decreased wholesale average prices, partially offset by higher average retail rates, increased wholesale sales volume and an increase in RTO capacity and other revenues. The revenue components for the year ended December 31, 2009 are further discussed below:

- Retail revenues increased $5.7 million resulting primarily from an 11% increase in average retail rates due largely to the incremental effect of the recovery of costs under the EIR combined with the implementation of the TCRR, RPM, Energy Efficiency and Alternative Energy riders, partially offset by a 9% decrease in sales volume driven largely by the effects of the economic recession and milder weather conditions. The milder weather conditions saw heating and cooling degree days decrease by 4% and 14% to 5,561 days and 734 days, respectively. As a result, retail revenues had a favorable $119.6 million price variance and an unfavorable $113.5 million sales volume variance.
- Wholesale revenues decreased $27.4 million primarily as a result of a 42% decrease in wholesale average prices partially offset by a 40% increase in sales volume, resulting in an unfavorable $87.0 million wholesale price variance and a favorable $59.6 million sales volume variance.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves as well as capacity payments under the RPM construct, increased $9.0 million compared to the same period in the prior year. This increase was primarily the result of additional revenue of $29.4 million that was realized from the PJM capacity auction, partially offset by a decrease in PJM transmission and congestion revenues of $21.0 million.

DPL — Cost of Revenues

For the year ended December 31, 2010:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, increased $53.5 million, or 16%, compared to 2009, primarily due to the impact of lower gains realized from the sale of **DP&L's** coal and excess emission allowances. During the year ended December 31, 2010, **DP&L** realized $4.1 million and $0.8 million in gains from the sale of coal and excess emission allowances, respectively, compared to $56.3 million and $5.0 million, respectively, realized during the same period in 2009. The effect of these lower gains was partially offset by the impact of a 2% decrease in the volume of generation by our plants.
- Net purchased power increased $127.2 million, or 49%, compared to the same period in 2009 due largely to an increase of $92.0 million in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This increase included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Also contributing to the increase in net purchased power was a $37.7 million increase related to higher average market prices for purchased power, partially offset by a $2.5 million decrease associated with lower purchased power volumes. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.

For the year ended December 31, 2009:

- Net fuel costs, which include coal gas, oil and emission allowances costs, increased $87.4 million, or 36%, compared to 2008, primarily due to the impact of lower gains realized from the sales of coal and excess emission allowances combined with a 7% increase in the usage of fuel due mainly to the improved performance of our generating facilities. In 2009, **DP&L** realized $56.3 million and $5.0 million in gains from the sales of coal and excess emission allowances, respectively, compared to $83.4 million and $34.8 million, respectively, during 2008. Also contributing to the increase in fuel costs was a 2% increase in the average cost of fuel consumed per kilowatt-hour largely resulting from higher market prices of coal combined with outages at lower-cost units.
- Net purchased power decreased $117.2 million compared to 2008. The net decrease in purchased power was due in part to lower volumes of purchased power and lower average market rates of $72.3 million and $29.5 million, respectively. The improved performance of our generating facilities, as mentioned in the preceding paragraph, resulted in increased generation output and a reduced demand for higher-cost purchased power. Also contributing to the decrease in purchased power were lower costs relating to other RTO charges as well as the net deferral during 2009 of costs relating to **DP&L's** transmission, capacity and other PJM-related charges which were incurred as a member of PJM. These decreases were partially offset by increased RTO capacity charges. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unanticipated outages, or when market prices are below the marginal costs associated with our generating facilities.

DPL - Operation and Maintenance

$ in millions		2010 vs. 2009
Energy efficiency programs *(1)*	$	11.1
Health insurance / long-term disability		8.9
Low-income payment program *(1)*		5.2
Pension		4.0
Generating facilities operating and maintenance expenses		3.8
Insurance settlement, net		(3.4)
Other, net		4.5
Total operation and maintenance expense	$	34.1

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

During the year ended December 31, 2010, Operation and maintenance expense increased $34.1 million, or 11%, compared to the same period in 2009. This variance was primarily the result of:

- higher expenses relating to energy efficiency programs that were put in place for our customers during 2009 and 2010,
- increased health insurance and disability costs primarily due to a number of employees going on long-term disability,
- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased pension costs due largely to a decline in the values of pension plan assets during 2008 and increased benefit costs, and
- increased expenses for generating facilities largely due to unplanned outages at jointly-owned production units.

These increases were partially offset by:

- an insurance settlement that reimbursed us for legal costs associated with our litigation against certain former executives.

$ in millions		2009 vs. 2008
Pension	$	6.2
Low-income payment program *(1)*		6.1
Energy efficiency programs *(1)*		5.9
Deferred compensation		4.1
ESOP		3.3
Health insurance		3.2
Deferred 2004/2005 storm costs and PJM administrative fees		(4.0)
Generating facilities operating and maintenance expenses		(1.4)
Other, net		0.6
Total operation and maintenance expense	$	24.0

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

During the year ended December 31, 2009, Operation and maintenance expense increased $24.0 million, or 8%, compared to 2008. This variance was primarily the result of:

- higher pension costs due largely to a decline in the values of pension plan assets from 2008 and increased benefit costs,
- increases in assistance for low-income retail customers which is funded by the USF revenue rate rider,
- expenses related to new energy efficiency programs put in place for our customers during 2009,
- increased deferred compensation costs,
- increases in employee benefit expense funded by the ESOP, and
- increased health insurance costs that were partially related to higher disability costs.

These increases were partially offset by:

- lower amortization of regulatory assets related to the 2004/2005 deferred storm costs and PJM administrative fees in 2009 as these deferred costs were fully recovered through rates during 2008 and in the first quarter of 2009, respectively, and
- decreases in expenses for generating facilities largely due to unplanned outages in 2008 at lower-cost production units resulting in higher costs in that year. These decreases were partially offset by increased maintenance expenses associated with unplanned outages at jointly-owned production units during 2009.

DPL — Depreciation and Amortization

During the year ended December 31, 2010, Depreciation and amortization expense decreased $6.1 million, or 4%, as compared to 2009. The decrease primarily reflects the impact of a depreciation study which resulted in lower depreciation rates on generation property which were implemented on July 1, 2010, reducing the expense by approximately $4.8 million during the year ended December 31, 2010.

During the year ended December 31, 2009, Depreciation and amortization expense increased $7.8 million, or 6%, as compared to 2008 primarily as a result of higher asset balances at the generating stations. These higher balances were due largely to the completion of the FGD projects during 2008.

DPL — General Taxes

During the year ended December 31, 2010, General taxes increased $9.3 million, or 8%, as compared to 2009. These increases were primarily the result of higher property tax accruals in 2010 compared to 2009, increased state excise taxes due to increased revenue and an adjustment to future credits against state gross receipt taxes.

During the year ended December 31, 2009, General taxes decreased $7.4 million, or 6%, as compared to 2008 primarily due to lower property tax accruals in 2009 compared to 2008 and lower kWh excise taxes resulting from lower retail sales volumes.

DPL — Investment Income (Loss)

During the year ended December 31, 2010, Investment income (loss) increased $2.4 million as compared to 2009 primarily as a result of the $1.4 million expense incurred in 2009 related to the early redemption of debt (see subsequent paragraph below). In addition, **DPL** had higher cash and short-term investment balances in 2010 compared to 2009 which resulted in higher investment income.

During the year ended December 31, 2009, Investment income (loss) decreased $4.2 million, or 117%, as compared to 2008 primarily as a result of lower cash and short-term investment balances combined with overall lower market yields on investments in 2009. In addition, we also recorded a $1.4 million expense during 2009 related to a loss incurred upon the early redemption of a debt obligation.

DPL — Interest Expense

During the year ended December 31, 2010, Interest expense decreased $12.4 million, or 15%, as compared to 2009 primarily due to the early redemption in December 2009 of $52.4 million of the $195 million 8.125% Note to DPL Capital Trust II and the redemption of **DPL's** $175 million 8.00% Senior Notes in March 2009. A premium of $3.7 million was incurred as an expense in 2009 upon the early debt redemption of $52.4 million referred to above.

During the year ended December 31, 2009, Interest expense decreased $7.7 million, or 8%, compared to 2008 primarily due to:

- a $12.8 million reduction in Interest expense due to the redemption of **DPL's** $175 million 8.00% Senior Notes and the $100 million 6.25% Senior Notes in March 2009 and May 2008, respectively,
- a $1.6 million write-off in 2008 of unamortized debt issuance costs relating to **DP&L's** $90 million variable rate pollution control bonds following their repurchase from the bondholders in April 2008, and
- $2.0 million of deferred interest carrying costs on regulatory assets primarily associated with the 2008 incremental storm costs and the riders for RPM and TCRR.

The above decreases were partially offset by $6.4 million of lower capitalized interest in 2009 compared to 2008, due largely to the completion of the FGD projects at our **DP&L** and partner-operated generating stations, as well as a $3.7 million premium paid upon the early redemption of $52.4 million of **DPL's** Note to DPL Capital Trust II.

DPL — Income Tax Expense

During the year ended December 31, 2010, Income tax expense increased $30.5 million, or 27%, as compared to 2009 primarily due to increases in pre-tax income.

During the year ended December 31, 2009, Income tax expense increased $9.6 million, or 9%, as compared to 2008, due to estimate to actual adjustments of 2008 taxes related to the Internal Revenue Code Section 199 deduction, adjustments to deferred tax liabilities and a 2008 settlement relating to the Ohio Franchise Tax. These increases were partially offset by a decrease in pre-tax book earnings, estimate to actual adjustments of 2008 state tax liabilities, adjustments to our current tax receivables and the phase-out of the Ohio Franchise Tax.

RESULTS OF OPERATIONS BY SEGMENT — DPL Inc.

During 2010, **DPL**, for the first time, met the GAAP requirements for separate segment reporting. **DPL's** two segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary. These segments are discussed further below:

Utility Segment

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

Competitive Retail Segment

The Competitive Retail segment is comprised of DPLER's competitive retail electric service business which sells retail electric energy under contract primarily to commercial and industrial customers who have selected DPLER as their alternative electric supplier. The Competitive Retail segment sells electricity to approximately 9,000 customers currently located throughout Ohio. Due to increased competition in Ohio, during 2010 we increased the number of employees and resources assigned to manage DPLER and increased its marketing to customers. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L**. During 2010, we implemented a new wholesale agreement between **DP&L** and DPLER. Under this agreement, intercompany sales from **DP&L** to DPLER were based on the market prices for wholesale power. In periods prior to 2010, DPLER's purchases from **DP&L** were transacted at prices that approximated DPLER's sales prices to its end-use retail customers. The Competitive Retail segment has no transmission or generation assets. The operations of DPLER are not subject to rate regulation by federal or state regulators.

Other

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

Management evaluates segment performance based on gross margin. In the discussions which follow, we have not provided extensive discussions of the results of operations related to 2009 and 2008 for the Competitive Retail segment because we believe that financial information is not comparable to the 2010 financial information. We have, however, included brief descriptions of the Competitive Retail segment's financial results for 2009 and 2008 for informational purposes as required by GAAP following the Income Statement Highlights table below.

See Note 17 of Notes to Consolidated Financial Statements for further discussion of **DPL's** reportable segments.

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

	For the years ended December 31,			Increase (Decrease)	
$ in millions	**2010**	**2009**	**2008**	**2010 vs 2009**	**2009 vs 2008**
Utility	**$ 1,035.1**	$ 967.6	$ 961.6	$ 67.5	$ 6.0
Competitive Retail	**38.5**	0.7	0.2	37.8	0.5
Other	**42.7**	33.7	23.1	9.0	10.6
Adjustments and Eliminations	**(4.5)**	(3.7)	(3.7)	(0.8)	—
Total consolidated	**$ 1,111.8**	$ 998.3	$ 981.2	$ 113.5	$ 17.1

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

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Income Statement Highlights — Competitive Retail Segment

$ in millions	For the years ended December 31, 2010	2009	2008	Increase (Decrease) 2010 vs 2009	2009 vs 2008
Revenues:					
Retail	$ 275.5	$ 64.8	$ 150.7	$ 210.7	$ (85.9)
RTO and other	1.5	0.7	0.1	0.8	0.6
	277.0	65.5	150.8	211.5	(85.3)
Cost of revenues:					
Purchased power	238.5	64.8	150.6	173.7	(85.8)
Gross margins (a)	38.5	0.7	0.2	37.8	0.5
Operation and maintenance expense	7.8	2.7	0.9	5.1	1.8
Other expenses (income), net	1.4	1.5	(3.2)	(0.1)	4.7
Total expenses, net	9.2	4.2	(2.3)	5.0	6.5
Earnings (Loss) from continuing operations before income tax	$ 29.3	$ (3.5)	$ 2.5	$ 32.8	$ (6.0)
Income tax expense (benefit)	10.5	(0.8)	0.6	11.3	(1.4)
Net income (Loss)	$ 18.8	$ (2.7)	$ 1.9	$ 21.5	$ (4.6)
Gross margin as a percentage of revenues	13.9%	1.1%	0.1%		

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

Competitive Retail Segment — Revenue

For the year ended December 31, 2010, the segment's retail revenues increased $210.7 million, or 325%, as compared to 2009. The increase was primarily driven by increased levels of competition in the competitive retail electric service business in the state of Ohio which in turn has resulted in a significant number of **DP&L's** retail customers switching their retail electric service to DPLER. Primarily as a result of the customer switching discussed above, the Competitive Retail segment sold approximately 4,546 million kWh of power to 9,002 customers during 2010 compared to 1,464 million kWh to 390 customers during 2009.

For the year ended December 31, 2009, the segment's retail revenues decreased $85.9 million, or 57%, as compared to 2008. This decrease primarily reflected customers switching their retail electric service from DPLER back to **DP&L** due to the expiration of a significant number of customers' service contracts at the end of 2008. As a result, the Competitive Retail segment sold approximately 1,464 million kWh of power to 390 customers during 2009 compared to 3,212 million kWh to 742 customers during 2008.

Competitive Retail Segment — Purchased Power

During the year ended December 31, 2010, the Competitive Retail segment purchased power increased $173.7 million, or 268%, as compared to 2009 primarily due to higher purchased power volumes required to satisfy an increase in customer base resulting from customer switching. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L**. During 2010, we implemented a new wholesale agreement between **DP&L** and DPLER. Under this agreement, intercompany sales from **DP&L** to DPLER were based on the market prices for wholesale power. In periods prior to 2010, DPLER's purchases from **DP&L** were transacted at prices that approximated DPLER's sales prices to its end-use retail customers. This increase was partially offset by lower average prices paid for purchased power in 2010.

During the year ended December 31, 2009, purchased power decreased $85.8 million, or 57%, as compared to 2008. This decrease was primarily associated with lower 2009 retail volumes due to the expiration of some customers' service contracts in 2008 as discussed under Competitive Retail Segment — Revenue above.

Competitive Retail Segment — Operation and Maintenance

DPLER's operation and maintenance expenses include employee-related expenses, accounting, information technology, payroll, legal and other administration expenses. The higher operation and maintenance expense in 2010 as compared to 2009 and 2008 is reflective of increased marketing and customer maintenance costs associated with the increased sales volume and number of customers.

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

Income Statement Highlights — DP&L

$ in millions	For the years ended December 31, 2010	2009	2008
Revenues:			
Retail	$ 1,185.4	$ 1,167.2	$ 1,075.3
Wholesale	365.8	181.9	293.5
RTO revenues	81.7	86.1	108.3
RTO capacity revenues	157.6	115.2	95.8
Total revenues	$ 1,790.5	$ 1,550.4	$ 1,572.9
Cost of revenues:			
Fuel costs	$ 376.8	$ 384.9	$ 349.6
Gains from sale of coal	(4.1)	(56.3)	(83.4)
Gains from sale of emission allowances	(0.8)	(5.0)	(34.8)
Net fuel	371.9	323.6	231.4
Purchased power	82.0	46.9	152.4
RTO charges	109.7	99.9	126.6
RTO capacity charges	191.8	112.4	100.9
Net purchased power	383.5	259.2	379.9
Total cost of revenues	$ 755.4	$ 582.8	$ 611.3
Gross margins (a)	$ 1,035.1	$ 967.6	$ 961.6
Gross margin as a percentage of revenues	57.8%	62.4%	61.1%
Operating income	$ 450.2	$ 421.9	$ 436.6

(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	2010 vs. 2009	2009 vs. 2008
Retail		
Rate	$ (46.9)	$ 191.7
Volume	63.4	(99.7)
Other	1.7	(0.1)
Total retail change	$ 18.2	$ 91.9
Wholesale		
Rate	$ 75.0	$ (230.5)
Volume	108.9	118.9
Total wholesale change	$ 183.9	$ (111.6)
RTO capacity and other		
RTO capacity and other revenues	$ 38.0	$ (2.8)
Total revenues change	$ 240.1	$ (22.5)

For the year ended December 31, 2010, Revenues increased $240.1 million, or 15%, to $1,790.5 million from $1,550.4 million in the prior year. This increase was primarily the result of higher retail and wholesale sales volumes, higher average wholesale prices as well as increased RTO capacity and other revenues, partially offset by lower average retail rates. The revenue components for the year ended December 31, 2010 are further discussed below:

- Retail revenues increased $18.2 million primarily as a result of a 6% increase in retail sales volumes compared to those in the prior year period largely due to more favorable weather and improved economic conditions. The favorable weather conditions resulted in a 70% increase in the number of cooling degree days to 1,245 days from 734 days in 2009. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to DPLER, an affiliated CRES provider, **DP&L** continued to provide distribution services to those customers within its service territory. The average retail rates decreased 4% overall primarily as a result of customers switching from **DP&L** to DPLER. The remaining distribution services provided by **DP&L** were billed at a lower rate resulting in a reduction of total average retail rates. The decrease in average retail rates resulting from customers switching was partially offset by the implementation of the fuel and energy efficiency riders, increased TCRR and RPM riders, and the incremental effect of the recovery of costs under the EIR. The above resulted in a favorable $63.4 million retail sales volume variance and an unfavorable $46.9 million retail price variance.
- Wholesale revenues increased $183.9 million primarily as a result of a 26% increase in average wholesale prices combined with a 60% increase in wholesale sales volume due in large part to the effect of customer switching discussed in the immediately preceding paragraph. **DP&L** records wholesale revenues from its sale of transmission and generation services to DPLER associated with these switched customers. This resulted in a favorable $108.9 million wholesale sales volume variance and a favorable wholesale price variance of $75.0 million.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, increased $38.0 million compared to the same period in 2009. This increase in RTO capacity and other revenues was primarily the result of a $42.4 million increase in revenues realized from the PJM capacity auction partially offset by a decrease of $4.4 million in transmission and congestion revenues.

For the year ended December 31, 2009, Revenues decreased $22.5 million, or 1%, to $1,550.4 million from $1,572.9 million in the prior year. This decrease was primarily the result of lower wholesale average prices and lower retail sales volume, partially offset by higher average retail rates and increased wholesale sales volume. The revenue components for the year ended December 31, 2009 are further discussed below:

- Retail revenues increased $91.9 million resulting primarily from a 20% increase in average retail rates due largely to the incremental effect of the EIR and the implementation of the TCRR, RPM, energy efficiency and alternative energy riders, partially offset by a 9% decrease in retail sales volume driven largely by the effects of the economic recession and milder weather conditions. The milder weather conditions saw heating and cooling degree days decrease by 4% and 14% to 5,561 days and 734 days, respectively. As a result, retail revenues had a favorable $191.7 million price variance and an unfavorable $99.7 million sales volume variance.
- Wholesale revenues decreased $111.6 million primarily as a result of a 56% decrease in wholesale average prices, partially offset by a 41% increase in sales volume, resulting in an unfavorable $230.5 million wholesale price variance and a favorable $118.9 million sales volume variance.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, as well as capacity payments under the RPM construct, decreased $2.8 million compared to the prior year. This decrease primarily resulted from $22.2 million of lower transmission and congestion revenues, partially offset by additional revenue of $19.4 million that was realized from the PJM capacity auction.

DP&L — Cost of Revenues

For the year ended December 31, 2010:

- Net fuel costs, which include coal, gas, oil, and emission allowance costs, increased $48.3 million, or 15%, compared to 2009, primarily due to the impact of lower gains realized from the sale of **DP&L's** coal and excess emission allowances. During the year ended December 31, 2010, **DP&L** realized $4.1 million and $0.8 million in gains from the sale of coal and excess emission allowances, respectively, compared to $56.3 million and $5.0 million, respectively, during 2009. The effect of these lower gains was partially offset by the impact of a 3% decrease in the volume of generation by our plants.
- Net purchased power increased $124.3 million, or 48%, compared to 2009, due largely to an increase of $89.2 million in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This increase included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Also contributing to the increase in net purchased power was a $37.6 million increase related to higher average market prices for purchased power, partially offset by a $2.5 million decrease associated with lower purchased power volumes. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.

For the year ended December 31, 2009:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, increased $92.2 million, or 40%, compared to 2008, primarily due to the impact of lower gains realized from the sales of coal and excess emission allowances combined with a 7% increase in the usage of fuel due mainly to the improved performance of our generating facilities. In 2009, **DP&L** realized $56.3 million and $5.0 million in gains from the sales of coal and excess emission allowances, respectively, compared to $83.4 million and $34.8 million, respectively, during 2008. Also contributing to the increase in fuel costs was a 3% increase in the average cost of fuel consumed per kilowatt-hour largely resulting from higher market prices of coal combined with outages at lower-cost units.
- Net purchased power decreased $120.7 million compared to 2008. The net decrease in purchased power was due in part to lower volumes of purchased power and lower average market rates of $74.8 million and $30.8 million, respectively. The improved performance of our generating facilities, as mentioned in the preceding paragraph, resulted in increased generation output and a reduced demand for higher-cost purchased power. Also contributing to the decrease in purchased power were lower costs relating to other RTO charges as well as the net deferral during 2009 of costs relating to **DP&L's** transmission, capacity and other PJM-related charges which were incurred as a member of PJM. This deferral is discussed in greater detail in Note 3 of Notes to Consolidated Financial Statements. These decreases were partially offset by increased RTO capacity charges. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unanticipated outages, or when market prices are below the marginal costs associated with our generating facilities.

DP&L — Operation and Maintenance

$ in millions	2010 vs. 2009
Energy efficiency programs *(1)*	$ 11.1
Health insurance / long-term disability	8.9
Low-income payment program *(1)*	5.1
Pension	4.0
Generating facilities operating and maintenance expenses	3.6
Other, net	4.0
Total operation and maintenance expense	$ 36.7

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

During the year ended December 31, 2010, Operation and maintenance expense increased $36.7 million, or 13%, compared to 2009. This variance was primarily the result of:

- higher expenses relating to energy efficiency programs that were put in place for our customers during 2009 and 2010,
- increased health insurance and disability costs primarily due to a number of employees going on long-term disability,
- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased pension costs due largely to a decline in the values of pension plan assets during 2008 and increased benefit costs, and
- increased expenses for generating facilities largely due to unplanned outages at jointly-owned production units.

$ in millions	2009 vs. 2008
Pension	$ 6.1
Low-income payment program *(1)*	6.1
Energy efficiency programs *(1)*	5.9
ESOP	3.3
Health insurance	3.2
Deferred 2004/2005 storm costs and PJM administrative fees	(4.0)
Generating facilities operating and maintenance expenses	(1.4)
Other, net	1.2
Total operation and maintenance expense	$ 20.4

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

During the year ended December 31, 2009, Operation and maintenance expense increased $20.4 million, or 7%, compared to 2008. This variance was primarily the result of:

- higher pension costs due largely to a decline in the values of pension plan assets from 2008 and increased benefit costs,
- increases in assistance for low-income retail customers which is funded by the USF revenue rate rider,
- expenses related to new energy efficiency programs put in place for our customers during 2009,
- increases in employee benefit expense funded by the ESOP, and
- increased health insurance costs that were partially related to higher disability costs.

These increases are partially offset by:

- lower amortization of regulatory assets related to the 2004/2005 deferred storm costs and PJM administrative fees in 2009 as these deferred costs were fully recovered through rates during 2008 and in the first quarter of 2009, respectively, and
- decreases in expenses for generating facilities largely due to unplanned outages in 2008 at lower-cost production units resulting in higher costs in that year. These decreases were partially offset by increased maintenance expenses associated with unplanned outages at jointly-owned production units during 2009.

DP&L — Depreciation and Amortization

During the year ended December 31, 2010, Depreciation and amortization expense decreased $4.8 million as compared to 2009. The decrease primarily reflected the impact of a depreciation study which resulted in lower depreciation rates on generation property which were implemented on July 1, 2010, reducing the expense by $3.4 million during the year ended December 31, 2010.

During the year ended December 31, 2009, Depreciation and amortization expense increased $7.7 million, or 6%, as compared to 2008 primarily as a result of higher asset balances at the generating stations. These higher balances were due largely to the completion of the FGD projects during 2008.

DP&L — General Taxes

During the year ended December 31, 2010, General taxes increased $7.3 million to $124.1 million compared to 2009. These increases were primarily the result of higher property tax accruals in 2010 compared to 2009, increased state excise taxes due to increased revenue and an adjustment to future credits against state gross receipt taxes.

During the year ended December 31, 2009, General taxes decreased $7.4 million, or 6%, compared to 2008 primarily due to lower property tax accruals in 2009 compared to 2008 and lower kWh excise taxes resulting from lower retail sales volumes.

DP&L — Investment Income

Investment income realized during 2010 did not fluctuate significantly from that realized during 2009.

During the year ended December 31, 2009, Investment income decreased $4.2 million, or 60%, as compared to 2008 primarily as a result of lower gains realized from the sale of **DPL** common stock from **DP&L's** Master Trust Plan used for deferred compensation distributions as well as lower cash and short-term investment balances combined with overall lower market yields on investments in 2009.

DP&L — Interest Expense

Interest expense recorded during 2010 did not fluctuate significantly from that recorded in 2009.

During the year ended December 31, 2009, Interest expense increased $2.0 million, or 5%, as compared to 2008 primarily as a result of $6.4 million of lower capitalized interest due largely to the completion of the FGD projects at our own and partner-operated generating stations. This increase was partially offset by:

- a $1.6 million write-off in 2008 of unamortized debt issuance costs relating to **DP&L's** $90 million variable rate pollution control bonds following their repurchase from the bondholders in April 2008, and
- $2.0 million of deferred interest carrying costs on regulatory assets primarily associated with the 2008 incremental storm costs and the riders for RPM and TCRR. These Regulatory assets are further discussed in Note 3 of Notes to Consolidated Financial Statements.

DP&L — Income Tax Expense

During the year ended December 31, 2010, Income tax expense increased $10.7 million compared to 2009 primarily due to increases in pre-tax income.

During 2009, Income tax expense increased $4.3 million, or 4%, compared to 2008, due to estimate to actual adjustments of 2008 income taxes related to the Internal Revenue Code Section 199 deduction, adjustments to deferred tax liabilities and a 2008 settlement relating to the Ohio Franchise Tax. These increases were partially offset by a decrease in pre-tax book earnings, estimate to actual adjustments of 2008 state tax liabilities, adjustments to our current tax receivables and the phase-out of the Ohio Franchise Tax.

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL REQUIREMENTS

DPL's financial condition, liquidity and capital requirements include the consolidated results of its principal subsidiary **DP&L**. All material intercompany accounts and transactions have been eliminated in consolidation. The following table provides a summary of the cash flows for **DPL** and **DP&L**:

DPL

	For the years ended December 31,		
$ in millions	**2010**	**2009**	**2008**
Net cash provided by operating activities	**$ 464.2**	$ 524.7	$ 361.2
Net cash used for investing activities	**(220.6)**	(164.7)	(252.9)
Net cash used for financing activities	**(194.5)**	(347.6)	(180.7)
Net change	**$ 49.1**	$ 12.4	$ (72.4)
Cash and cash equivalents at beginning of period	**74.9**	62.5	134.9
Cash and cash equivalents at end of period	**$ 124.0**	$ 74.9	$ 62.5

DP&L

	For the years ended December 31,		
$ in millions	**2010**	**2009**	**2008**
Net cash provided by operating activities	**$ 446.4**	$ 513.7	$ 392.7
Net cash used for investing activities	**(148.6)**	(166.0)	(240.1)
Net cash used for financing activities	**(300.9)**	(311.4)	(145.0)
Net change	**$ (3.1)**	$ 36.3	$ 7.6
Cash and cash equivalents at beginning of period	**57.1**	20.8	13.2
Cash and cash equivalents at end of period	**$ 54.0**	$ 57.1	$ 20.8

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

Net Cash Provided by Operating Activities

The revenue from our energy business continues to be the principal source of cash from operating activities while our primary uses of cash include payments for fuel, purchased power, operation and maintenance expenses, interest and taxes. Management believes that the diversified retail customer mix of residential, commercial and industrial classes coupled with rate relief approved by the PUCO provides us with a reasonably predictable gross cash flow from operations.

DPL — Net Cash provided by Operating Activities

DPL's Net cash provided by operating activities for the years ended December 31, 2010, 2009 and 2008 can be summarized as follows:

$ in millions	2010	2009	2008
Earnings from continuing operations	**$ 290.3**	$ 229.1	$ 244.5
Depreciation and amortization	**139.4**	145.5	137.7
Deferred income taxes	**59.9**	201.6	43.1
Income tax settlement	**—**	—	(42.0)
Contribution to pension plan	**(40.0)**	—	—
Deferred regulatory costs, net	**16.0**	(24.6)	(12.9)
Other	**(1.4)**	(26.9)	(9.2)
Net cash provided by operating activities	**$ 464.2**	$ 524.7	$ 361.2

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

- The $59.9 million increase to Deferred income taxes primarily results from changes related to pension contributions, depreciation expense and repair expense.
- **DP&L** contributed $40.0 million to the defined benefit pension plan in 2010.
- $16.0 million of cash collected to pay for fuel, purchased power and other fuel related costs and transmission, capacity and other PJM-related costs incurred during 2010, in excess of cash expenditures. These costs reduced the Regulatory asset in accordance with the provisions of GAAP relating to regulatory accounting (see Note 3 of Notes to Consolidated Financial Statements) and are expected to reduce the amount to be collected from customers in future periods.
- Other represents items that had a current period cash flow impact and includes changes in working capital and other future rights or obligations to receive or to pay cash. These items are primarily impacted by, among other factors, the timing of when cash payments are made for fuel, purchased power, operating costs, interest and taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances.

For the year ended December 31, 2009, Net cash provided by operating activities was primarily a result of Earnings from continuing operations adjusted for noncash depreciation and amortization, combined with the following significant transactions:

- The $201.6 million increase to Deferred income taxes primarily results from the recognition of certain tax benefits for 2008 and 2009 relating to a change in the tax accounting method for deductions pertaining to repairs, depreciation and mixed service costs. Primarily due to the recognition of these benefits during 2009, **DPL** received a net cash refund of state and federal income taxes totaling $94.6 million and, in addition, was able to offset $69.0 million of these benefits against income tax liabilities accrued in 2009.
- $24.6 million of cash used primarily to pay for transmission, capacity and other PJM-related costs incurred during 2009, net of recoveries. These costs were recorded as a Regulatory asset in accordance with the provisions of GAAP relating to regulatory accounting (see Note 3 of Notes to Consolidated Financial Statements) and are expected to be collected from customers during future years.
- Other represents items that had a current period cash flow impact and includes changes in working capital and other future rights or obligations to receive or to pay cash. These items are primarily impacted by, among other factors, the timing of when cash payments are made for fuel, purchased power, operating costs, interest and taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances.

For the year ended December 31, 2008, Net cash provided by operating activities was primarily a result of Earnings from continuing operations adjusted for noncash depreciation and amortization, combined with the following significant transactions:

- Deferred income taxes increased by $43.1 million as a result of the acceleration of the deduction of newly installed FGD and SCR equipment for tax purposes, which had the effect of reducing current period income tax payments and increasing cash on hand.
- The $42 million cash payment made in 2008 to the ODT following a tax settlement agreement.
- $13.1 million of cash used to restore damage of a non-capital nature caused by the hurricane-force winds of September 2008 and other major 2008 storms. These costs were recorded as a Regulatory asset in accordance with the provisions of GAAP relating to regulatory accounting (see Note 3 of Notes to Consolidated Financial Statements) and are expected to be collected from customers during future years.
- Other represents items that had a current period cash flow impact and includes changes in working capital and other future rights or obligations to receive or to pay cash. These items are primarily impacted by, among other factors, the timing of when cash payments are made for fuel, purchased power, operating costs, interest and taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances.

DP&L — Net Cash provided by Operating Activities

DP&L's Net cash provided by operating activities for the years ended December 31, 2010, 2009 and 2008 can be summarized as follows:

$ in millions	2010	2009	2008
Net income	$ **277.7**	$ 258.9	$ 285.8
Depreciation and amortization	**130.7**	135.5	127.8
Deferred income taxes	**54.3**	200.1	40.9
Income tax settlement	**—**	—	(42.0)
Contribution to pension plan	**(40.0)**	—	—
Deferred regulatory costs, net	**16.0**	(24.6)	(12.9)
Other	**7.7**	(56.2)	(6.9)
Net cash provided by operating activities	$ **446.4**	$ 513.7	$ 392.7

For the years ended December 31, 2010, 2009 and 2008, the significant components of **DP&L's** Net cash provided by operating activities are similar to those discussed under **DPL's** Net cash provided by operating activities above.

DPL and DP&L — Net Cash used for Investing Activities

DPL and DP&L's Net cash used for investing activities for the years ended December 31, 2010, 2009 and 2008 can be summarized as follows:

$ in millions	2010	2009	2008
DP&L			
Environmental and renewable energy capital expenditures	$ **(11.9)**	$ (21.2)	$ (90.2)
Capital upgrades due to 2008 storms	**—**	—	(18.6)
Other plant-related asset acquisitions	**(138.1)**	(146.2)	(133.2)
Other	**1.4**	1.4	1.9
DP&L's net cash used for investing activities	$ **(148.6)**	$ (166.0)	$ (240.1)
Proceeds from sale of short-term investments	**17.1**	25.7	34.2
Purchases of short-term investments	**(86.4)**	(20.7)	(39.1)
Other	**(2.7)**	(3.7)	(7.9)
DPL's net cash used for investing activities	$ **(220.6)**	$ (164.7)	$ (252.9)

For the year ended December 31, 2010, **DP&L** continued to see reductions in its environmental capital expenditures due to the completion of FGD and SCR projects including the FGD and SCR equipment completed and placed into service at Conesville during the fourth quarter of 2009. Approximately $4.2 million of the environmental capital expenditures incurred during 2010 relate to the construction of a solar energy facility at Yankee station. **DP&L** also continued to make upgrades and other investments in other generation, transmission and distribution equipment. Additionally, **DPL** purchased $54.2 million of VRDN securities, net of redemptions from various institutional securities brokers as well as $15.1 million of investment-grade fixed income corporate bonds. The VRDN securities are backed by irrevocable letters of credit. These securities have variable coupon rates that are typically re-set weekly relative to various short-term rate indices. **DPL** can tender these VRDN securities for sale upon notice to the broker and receive payment for the tendered securities within seven days.

For the year ended December 31, 2009, **DP&L** continued to see reductions in its environmental-related capital expenditures due to the completion of FGD and SCR projects. The expenditures in 2009 relate to the construction of FGD and SCR equipment at the Conesville generation station which was substantially completed and placed into service during the fourth quarter of 2009. **DP&L** also continued to make upgrades and other investments in other generation, transmission and distribution equipment.

For the year ended December 31, 2008, **DP&L** saw reduced cash outflows associated with environmental-related expenditures compared to 2007 due to projects relating to the installation of FGD and SCR equipment that had either been completed or were nearing completion. In addition, **DP&L** was forced to replace a portion of its distribution lines and equipment following the damage caused by the hurricane-force winds of September 2008 and other 2008 storms.

DPL — Net Cash used for Financing Activities

DPL's Net cash used for financing activities for the years ended December 31, 2010, 2009 and 2008 can be summarized as follows:

$ in millions	2010	2009	2008
Dividends paid on common stock	$ **(139.7)**	$ (128.8)	$ (120.5)
Repurchase of DPL common stock	**(56.4)**	(64.4)	—
Retirement of long-term debt	—	(227.4)	(100.0)
Repurchase of warrants	—	(25.2)	—
Proceeds from exercise of warrants	—	77.7	—
Cash withdrawn from restricted funds	—	14.5	32.5
Proceeds from exercise of stock options	**1.4**	9.0	2.2
Other	**0.2**	(3.0)	5.1
Net cash used for financing activities	$ **(194.5)**	$ (347.6)	$ (180.7)

For the year ended December 31, 2010, **DPL** paid common stock dividends of $139.7 million. In addition, under the stock repurchase programs approved by the Board of Directors in October 2009 and October 2010 (see Note 12 of Notes to Consolidated Financial Statements), **DPL** repurchased approximately 2.18 million **DPL** common shares for $56.4 million.

For the year ended December 31, 2009, **DPL** redeemed long-term debt totaling $227.4 million and paid common stock dividends of $128.8 million. Under a stock repurchase program approved by the Board of Directors in October 2009 (see Note 12 of Notes to Consolidated Financial Statements), **DPL** repurchased approximately 2.4 million **DPL** common shares for $64.4 million. In addition, **DPL** repurchased 8.6 million warrants for $25.2 million. **DPL's** cash inflows during the period include $77.7 million received from the cash exercise of 3.7 million warrants and the withdrawal of the remaining balance of restricted funds of $14.5 million which was used primarily to fund the construction of FGD equipment at the Conesville generation station. **DPL** also received $9.0 million from option holders who exercised stock options due, in part, to the increase in our average stock price compared to 2008.

For the year ended December 31, 2008, **DPL** paid common stock dividends of $120.5 million, retired $100 million of long-term debt and withdrew $32.5 million from restricted funds held in trust to pay for environmental-related capital expenditures.

DP&L — Net Cash used for Financing Activities

DP&L's Net cash used for financing activities for the years ended December 31, 2010, 2009 and 2008 can be summarized as follows:

$ in millions	2010	2009	2008
Dividends paid on common stock to parent	$ **(300.0)**	$ (325.0)	$ (155.0)
Net loan (paid to) / received from parent	—	—	(20.0)
Cash withdrawn from restricted funds	—	14.5	32.5
Other	**(0.9)**	(0.9)	(2.5)
Net cash used for financing activities	$ **(300.9)**	$ (311.4)	$ (145.0)

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

For the year ended December 31, 2009, **DP&L** paid $325 million in dividends to **DPL** and withdrew the remaining balance of $14.5 million from restricted funds to pay for the Conesville FGD and SCR projects.

For the year ended December 31, 2008, **DP&L** paid $155 million in dividends to **DPL,** withdrew $32.5 million from restricted funds held in trust and repaid the net $20 million short-term loan from **DPL.**

Liquidity

We expect our existing sources of liquidity to remain sufficient to meet our anticipated obligations. Our business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities, taxes, interest and dividend payments. For 2011 and subsequent years, we expect to satisfy these requirements with a combination of cash from operations and funds from the capital markets as our internal liquidity needs and market conditions warrant. We also expect that the borrowing capacity under credit facilities will continue to be available to manage working capital requirements during those periods.

At the filing date of this annual report on Form 10-K, **DP&L** has access to $420 million of short-term financing under two revolving credit facilities. The first facility for $220 million expires in November 2011 and has three participating banks; the lead bank has a total commitment of 36% while the other two have commitments of 32% each. The second facility, established in April 2010, is for $200 million and expires in April 2013. A total of five banks participate in this facility, with no bank having more than 35% of the total commitment.

$ in millions	Type	Maturity	Commitment	Amounts available at December 31, 2010
DP&L	Revolving	November 2011	$ 220.0	$ 220.0
DP&L	Revolving	April 2013	200.0	200.0
			$ 420.0	$ 420.0

Each revolving credit facility has a $50 million LOC sublimit. As of December 31, 2010 and through the date of filing this annual report on Form 10-K, there were no outstanding LOCs on either facility.

DPL's $297.4 million 6.875% senior notes due September 2011 have been reflected as a current liability. Management will continue to monitor and evaluate market conditions over the next several months and make a determination to either seek to refinance the senior notes or explore alternative financing arrangements.

Cash and cash equivalents for **DPL** and **DP&L** amounted to $124.0 million and $54.0 million, respectively, at December 31, 2010. At that date, **DPL** also had short-term investments amounting to $69.3 million.

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

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

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

Capital Requirements

CONSTRUCTION ADDITIONS

	Actual			Projected		
$ in millions	**2010**	**2009**	**2008**	**2011**	**2012**	**2013**
DPL	$ **151**	$ 145	$ 228	$ 310	$ 260	$ 200
DP&L	$ **148**	$ 144	$ 225	$ 300	$ 255	$ 195

Planned construction additions for 2011 relate primarily to new investments in and upgrades to **DP&L's** power plant equipment, and transmission and distribution system. Capital projects are subject to continuing review and are revised in light of changes in financial and economic conditions, load forecasts, legislative and regulatory developments and changing environmental standards, among other factors.

DPL, through its subsidiary **DP&L**, is projecting to spend an estimated $770 million in capital projects for the period 2011 through 2013. Approximately $20 million of this projected amount is to enable **DP&L** to meet the recently revised reliability standards of NERC. **DP&L** is subject to the mandatory reliability standards of NERC, and Reliability First Corporation (RFC), one of the eight NERC regions, of which **DP&L** is a member. NERC has recently changed the definition of the Bulk Electric System (BES) to include 100 kV and above facilities, thus expanding the facilities to which the reliability standards apply. **DP&L's** 138 kV facilities were previously not subject to these reliability standards. Accordingly, **DP&L** anticipates spending approximately $100 million within the next 5 years to reinforce its 138 kV system to comply with these new NERC standards. Our ability to complete capital projects and the reliability of future service will be affected by our financial condition, the availability of internal funds and the reasonable cost of external funds. We expect to finance our construction additions with a combination of cash on hand, short-term financing, long-term debt and cash flows from operations.

Debt Covenants

As mentioned above, **DP&L** has access to $420 million of short-term financing under its two revolving credit facilities. The following financial covenant is contained in each revolving credit facility: **DP&L's** total debt to total capitalization ratio is not to exceed 0.65 to 1.00. As of December 31, 2010, this covenant was met with a ratio of 0.40 to 1.00. The above ratio is calculated as the sum of **DP&L's** current and long-term portion of debt, including its guaranty obligations, divided by the total of **DP&L's** shareholders' equity and total debt including guaranty obligations.

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Credit Ratings

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

	DPL (a)	DP&L (b)	Outlook	Effective
Fitch Ratings	A-	AA-	Stable	October 2010
Moody's Investors Service	Baa1	Aa3	Stable	June 2010
Standard & Poor's Corp.	BBB+	A	Stable	April 2010

(a) Credit rating relates to ***DPL's*** *Senior Unsecured debt.*

(b) Credit rating relates to ***DP&L's*** *Senior Secured debt.*

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 DPLE and DPLER on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish DPLE's and DPLER's intended commercial purposes. During the year ended December 31, 2010, **DPL** did not incur any losses related to the guarantees of DPLE's and DPLER's 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 of DPLE's and DPLER's obligations.

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

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

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, 2010, these include:

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

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

Long-term debt:

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

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

See Note 5 of Notes to Consolidated Financial Statements.

Interest payments:

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

Pension and postretirement payments:

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

Capital leases:

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

Operating leases:

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

Coal contracts:

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

Limestone contracts:

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

Purchase orders and other contractual obligations:

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

Reserve for uncertain tax positions:

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

MARKET RISK

We are subject to certain market risks including, but not limited to, changes in commodity prices for electricity, coal, environmental emissions and gas, changes in capacity prices and fluctuations in interest rates. We use various market risk sensitive instruments, including derivative contracts, primarily to limit our exposure to fluctuations in commodity pricing. Our Commodity Risk Management Committee (CRMC), comprising of members of senior management, is responsible for establishing risk management policies and the monitoring and reporting of risk exposures relating to our **DP&L**-operated generation units. The CRMC meets on a regular basis with the objective of identifying, assessing and quantifying material risk issues and developing strategies to manage these risks.

Commodity Pricing Risk

Commodity pricing risk exposure includes the impacts of weather, market demand, increased competition and other economic conditions. To manage the volatility relating to these exposures at our **DP&L**-operated generation units, we use a variety of non-derivative and derivative instruments including forward contracts and futures contracts. These instruments are used principally for economic hedging purposes and none are held for trading purposes. Derivatives that fall within the scope of derivative accounting under GAAP must be recorded at their fair value and marked to market unless they qualify for cash flow hedge accounting. MTM gains and losses on derivative instruments that qualify for cash flow hedge accounting are deferred in AOCI until the forecasted transactions occur. We adjust the derivative instruments that do not qualify for cash flow hedging to fair value on a monthly basis and where applicable, we recognize a corresponding Regulatory asset for above-market costs or a Regulatory liability for below-market costs in accordance with regulatory accounting under GAAP.

The coal market has increasingly been influenced by both international and domestic supply and consumption, making the price of coal more volatile than in the past, and while we have substantially all of the total expected coal volume needed to meet our retail and firm wholesale sales requirements for 2011 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 generation plant mix. To the extent we are not able to hedge against price volatility or recover increases through our fuel and purchased power recovery rider that began in January 2010; our results of operations, financial condition or cash flows could be materially affected.

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

For purposes of potential risk analysis, we use a sensitivity analysis to quantify potential impacts of market rate changes on the statements of results of operations. The sensitivity analysis represents hypothetical changes in market values that may or may not occur in the future.

Commodity Derivatives

To minimize the risk of fluctuations in the market price of commodities, such as coal, power, and heating oil, we may enter into commodity-forward and futures contracts to effectively hedge the cost/revenues of the commodity. Maturity dates of the contracts are scheduled to coincide with market purchases/sales of the commodity. Cash proceeds or payments between us and the counter-party at maturity of the contracts are recognized as an adjustment to the cost of the commodity purchased or sold. We generally do not enter into forward contracts beyond thirty-six months.

A 10% increase or decrease in the market price of our wholesale power forward contracts and heating oil forwards at December 31, 2010 would not have a significant effect on Net income.

The following table provides information regarding the volume and average market price of our NYMEX coal forward derivative contracts at December 31, 2010 and the effect to Net income if the market price were to increase or decrease by 10%:

NYMEX Coal Forwards	Contract Volume (in millions of Tons)	Weighted Average Market Price (per Ton)	Increase / Decrease in Net Income (in millions) (a)
2011-Purchase	1.0	$ 80.30	$ 1.4
2012-Purchase	2.9	$ 83.53	$ 4.8
2013-Purchase	0.1	$ 86.08	$ 0.5

(a) The Net Income effect of a 10% change in the market price of NYMEX Coal has been partially off-set by our partners' share of the gain or loss associated with the jointly-owned power plants and also by the retail customers' share of the gain or loss which is deferred on the balance sheet in conjunction with the fuel and purchased power recovery rider.

Wholesale Revenues

Approximately 17% of **DPL's** and 16% of **DP&L's** electric revenues for the year ended December 31, 2010 were from sales of excess energy and capacity in the wholesale market (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER). Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

Approximately 16% of **DPL's** and 15% of **DP&L's** electric revenues for the year ended December 31, 2009 were from sales of excess energy and capacity in the wholesale market. Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

The table below provides the effect on annual Net income as of December 31, 2010, of a hypothetical increase or decrease of 10% in the price per megawatt hour of wholesale power (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER), including the impact of a corresponding 10% change in the portion of purchased power used as part of the sale (note the share of the internal generation used to meet the DPLER wholesale sale would not be affected by the 10% change in wholesale prices):

$ in millions	DPL	DP&L
Effect of 10% change in price per mWh	$ 10.1	$ 8.6

RPM Capacity Revenues and Costs

As a member of PJM, **DP&L** receives revenues from the RTO related to its transmission and generation assets and incurs costs associated with its load obligations for retail customers. PJM, which has a delivery year which runs from June 1 to May 31, has conducted auctions for capacity through the 2013/14 delivery year. The clearing prices for capacity during the PJM delivery periods from 2008/9 through 2013/14 are as follows:

	PJM Delivery Year					
	2008/9	2009/10	2010/11	2011/12	2012/13	2013/14
Capacity clearing price ($/MW-day)	112	102	174	110	16	28

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

	Calendar Year				
	2009	2010	2011	2012	2013
Computed average capacity price ($/MW-day)	106	144	137	55	23

Future RPM auction results are dependent on a number of factors, which include the overall supply and demand of generation and load, other state legislation or regulation, transmission congestion, and PJM's RPM business rules. The volatility in the RPM capacity auction pricing has had and will continue to have a significant impact on **DPL's** capacity revenues and costs. Although **DP&L** currently has an approved RPM rider in place to recover or repay any excess capacity costs or revenues, the RPM rider only applies to customers supplied under our SSO. Customer switching reduces the number of customers supplied under our SSO, causing more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation.

The table below provides estimates of the effect on annual net income as of December 31, 2010, of a hypothetical increase or decrease of $10 in the RPM auction price. The table shows the impact resulting from capacity revenue changes. We did not include the impact of a change in the RPM capacity costs since these costs will either be recovered through the RPM rider for SSO retail customers or recovered through the development of our overall energy pricing for customers who do not fall under the SSO. These estimates include the impact of the RPM rider and are based on the 2010 levels of customer switching. As of December 31, 2010, approximately 60% of **DP&L's** RPM capacity revenues and costs were recoverable from SSO retail customers through the RPM rider.

$ in millions	DPL	DP&L
Effect of a $10 change in capacity auction pricing	$ 4.4	$ 3.1

Capacity revenues and costs are also impacted by, among other factors, the levels of customer switching, our generation capacity, the levels of wholesale revenues and our retail customer load. In determining the capacity price sensitivity above, we did not consider the impact that may arise from the variability of these other factors.

Fuel and Purchased Power Costs

DPL's and **DP&L's** fuel (including coal, gas, oil and emission allowances) and purchased power costs as a percentage of total operating costs in the years ended December 31, 2010 and 2009 were 34% and 33%, respectively. We have substantially all of the total expected coal volume needed to meet our retail and firm wholesale sales requirements for 2011 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 2011; however, the exact consumption of SO_2 allowances will depend on market prices for power, availability of our generation units and the actual sulfur content of the coal burned. We may purchase some NOx allowances for 2011 depending on NOx emissions. Fuel costs are affected by changes in volume and price and are driven by a number of variables including weather, reliability of coal deliveries, scheduled outages and generation plant mix.

Purchased power costs depend, in part, upon the timing and extent of planned and unplanned outages of our generating capacity. We will purchase power on a discretionary basis when wholesale market conditions provide opportunities to obtain power at a cost below our internal generation costs.

Effective January 1, 2010, **DP&L** was allowed to recover its SSO retail customers' share of fuel and purchased power costs, of approximately 60% of retail sales, as part of the fuel rider approved by the PUCO. The table below provides the effect on annual net income as of December 31, 2010, of a hypothetical increase or decrease of 10% in the prices of fuel and purchased power, adjusted for the approximate 60% recovery:

$ in millions	DPL	DP&L
Effect of 10% change in fuel and purchased power	$ 13.0	$ 12.6

Interest Rate Risk

As a result of our normal investing and borrowing activities, our financial results are exposed to fluctuations in interest rates, which we manage through our regular financing activities. We maintain both cash on deposit and investments in cash equivalents that may be affected by adverse interest rate fluctuations. **DPL** has fixed-rate long-term debt and **DP&L** has both fixed and variable-rate long-term debt. **DP&L's** variable-rate debt is comprised of publicly held pollution control bonds. The variable-rate bonds bear interest based on a prevailing rate that is reset weekly based on a comparable market index. Market indexes can be affected by market demand, supply, market interest rates and other economic conditions.

We partially hedge against interest rate fluctuations by entering into interest rate swap agreements to limit the interest rate exposure on the underlying financing. As of December 31, 2010, we have entered into interest rate hedging relationships with an aggregate notional amount of $200 million and $160 million related to planned future borrowing activities in calendar year 2011 and calendar year 2013, respectively. The average interest rate associated with the $200 million and $160 million aggregate notional amount interest rate hedging relationships is 4.1% and 3.8%, respectively. During the first quarter of 2011, we entered into additional interest rate hedging relationships with an aggregate notional amount of $75 million related to planned future borrowing activities in calendar year 2011. The average interest rate associated with the additional $75 million aggregate notional amount interest rate hedging relationships is 4.0%. We are limiting our exposure to changes in interest rates since we believe the market interest rates at which we will be able to borrow in the future may increase.

The carrying value of **DPL's** debt was $1,324.1 million at December 31, 2010, consisting of **DP&L's** first mortgage bonds, **DP&L's** tax-exempt pollution control bonds, **DPL's** unsecured notes and **DP&L's** capital lease. The fair value of this debt was $1,307.5 million, based on current market prices or discounted cash flows using current rates for similar issues with similar terms and remaining maturities. The following table provides information about **DPL's** debt obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

DPL

$ in millions	2011	2012	2013	2014	2015	Thereafter	Carrying value at December 31, 2010 (a)	Fair value at December 31, 2010 (a)
Long-term debt								
Variable-rate debt	$ —	$ —	$ —	$ —	$ —	$ 100.0	$ 100.0	$ 100.0
Average interest rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	
Fixed-rate debt	$ 297.5	$ 0.1(b)	$ 470.0	$ —	$ —	$ 456.5	$ 1,224.1	$ 1,207.5
Average interest rate	6.9%	0.0%	5.1%	0.0%	0.0%	5.8%	5.8%	
Total							$ 1,324.1	$ 1,307.5

(a) Fixed rate debt totals include unamortized debt discounts.

(b) Amount represents a capital lease obligation.

The carrying value of **DP&L's** debt was $884.1 million at December 31, 2010, consisting of its first mortgage bonds, tax-exempt pollution control bonds and a capital lease. The fair value of this debt was $850.6 million, based on current market prices or discounted cash flows using current rates for similar issues with similar terms and remaining maturities. The following table provides information about **DP&L's** debt obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date
DP&L

$ in millions	2011	2012	2013	2014	2015	Thereafter	Carrying value at December 31, 2010 (a)	Fair value at December 31, 2010 (a)
Long-term debt								
Variable-rate debt	$ —	$ —	$ —	$ —	$ —	$ 100.0	$ 100.0	$ 100.0
Average interest rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	
Fixed-rate debt	$ 0.1(b)	$ 0.1(b)	$ 470.0	$ —	$ —	$ 313.9	$ 784.1	$ 750.6
Average interest rate	0.0%	0.0%	5.1%	0.0%	0.0%	4.8%	5.0%	
Total							$ 884.1	$ 850.6

(a) Fixed rate debt totals include unamortized debt discounts.
(b) Amount represents a capital lease obligation.

Debt maturities occurring in 2011 are discussed under FINANCIAL CONDITION, LIQUIDITY AND CAPITAL REQUIREMENTS.

Long-term Debt Interest Rate Risk Sensitivity Analysis

Our estimate of market risk exposure is presented for our fixed-rate and variable-rate debt at December 31, 2010 and 2009 for which an immediate adverse market movement causes a potential material impact on our financial condition, results of operations, or the fair value of the debt. We believe that the adverse market movement represents the hypothetical loss to future earnings and does not represent the maximum possible loss nor any expected actual loss, even under adverse conditions, because actual adverse fluctuations would likely differ. As of December 31, 2010 and 2009, we did not hold any market risk sensitive instruments which were entered into for trading purposes.

DPL

$ in millions	Carrying value at December 31, 2010	Fair value at December 31, 2010	One Percent Interest Rate Risk	Carrying value at December 31, 2009	Fair value at December 31, 2009	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	$ 100.0	$ 100.0	$ 1.0	$ 100.0	$ 100.0	$ 1.0
Fixed-rate debt	1,224.1	1,207.5	12.1	1,224.1	1,217.6	12.2
Total	$ 1,324.1	$ 1,307.5	$ 13.1	$ 1,324.1	$ 1,317.6	$ 13.2

DP&L

$ in millions	Carrying value at December 31, 2010	Fair value at December 31, 2010	One Percent Interest Rate Risk	Carrying value at December 31, 2009	Fair value at December 31, 2009	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	$ 100.0	$ 100.0	$ 1.0	$ 100.0	$ 100.0	$ 1.0
Fixed-rate debt	784.1	750.6	7.5	784.3	744.5	7.5
Total	$ 884.1	$ 850.6	$ 8.5	$ 884.3	$ 844.5	$ 8.5

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** $1,224.1 million of fixed-rate debt and not on **DPL's** financial condition or results of operations. On the variable-rate debt, the interest rate risk with respect to **DPL's** long-term debt represents the potential impact an increase of one percentage point in the interest rate has on **DPL's** results of operations related to **DP&L's** $100 million variable-rate long-term debt outstanding as of December 31, 2010.

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** $784.1 million of fixed-rate debt and not on **DP&L's** financial condition or **DP&L's** results of operations. On the variable-rate debt, the interest rate risk with respect to **DP&L's** long-term debt represents the potential impact an increase of one percentage point in the interest rate has on **DP&L's** results of operations related to **DP&L's** $100.0 million variable-rate long-term debt outstanding as of December 31, 2010.

Equity Price Risk

As of December 31, 2010, approximately 41% of the defined benefit pension plan assets were comprised of investments in equity securities and 59% 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 $119.9 million at December 31, 2010. A hypothetical 10% decrease in prices quoted by stock exchanges would result in an $12.0 million reduction in fair value as of December 31, 2010 and approximately a $1.0 million increase to the 2011 pension expense.

Credit Risk

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. We limit our credit risk by assessing the creditworthiness of potential counterparties before entering into transactions with them and continue to evaluate their creditworthiness after transactions have been originated. We use the three leading corporate credit rating agencies and other current market-based qualitative and quantitative data to assess the financial strength of counterparties on an ongoing basis. We may require various forms of credit assurance from counterparties in order to mitigate credit risk.

CRITICAL ACCOUNTING ESTIMATES

DPL's and **DP&L's** Consolidated Financial Statements are prepared in accordance with U.S. GAAP. In connection with the preparation of these financial statements, our management is required to make assumptions, estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the related disclosure of contingent liabilities. These assumptions, estimates and judgments are based on our historical experience and assumptions that we believe to be reasonable at the time. However, because future events and their effects cannot be determined with certainty, the determination of estimates requires the exercise of judgment. Our critical accounting estimates are those which require assumptions to be made about matters that are highly uncertain.

Different estimates could have a material effect on our financial results. Judgments and uncertainties affecting the application of these policies and estimates may result in materially different amounts being reported under different conditions or circumstances. Historically, however, recorded estimates have not differed materially from actual results. Significant items subject to such judgments include: the carrying value of property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits.

Impairments and Assets Held for Sale: In accordance with the provisions of GAAP relating to the accounting for 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.

Revenue Recognition (including Unbilled Revenue): We consider revenue realized, or realizable, and earned when persuasive evidence of an arrangement exists, the products or services have been provided to the customer, the sales price is fixed or determinable, and collection is reasonably assured. The determination of the energy sales to customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. We recognize revenues using an accrual method for retail and other energy sales that have not yet been billed, but where electricity has been consumed. This is termed "unbilled revenues" and is a widely recognized and accepted practice for utilities. At the end of each month, unbilled revenues are determined by the estimation of unbilled energy provided to customers since the date of the last meter reading, projected line losses, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Given our estimation method and the fact that customers are billed monthly, we believe it is unlikely that materially different results will occur in future periods when these amounts are subsequently billed.

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

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

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

We evaluate our Regulatory assets to determine whether or not they are probable of recovery through future rates and make various assumptions in our analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions or historical experience, as well as discussions with applicable regulatory authorities. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period the assessment is made. We currently believe the recovery of our Regulatory assets is probable. See Note 3 of Notes to Consolidated 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 retirement, whether legal AROs or not, must be removed from a company's accumulated depreciation reserve. We make assumptions, estimates and judgments that affect the reported amounts of assets, liabilities and expenses as they relate to AROs. These assumptions and estimates are based on historical experience and assumptions that we believe to be reasonable at the time.

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

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

For 2011, we have decreased our long-term rate of return assumption from 8.50% to 8.00% for pension plan assets. We are maintaining our long-term rate of return assumption of 6.00% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our current portfolio mixes. We have decreased our assumed discount rate to 5.31% from 5.75% for pension and to 4.96% from 5.35% for postretirement benefits expense to reflect current duration-based yield curve discount rates. A one percent change in the rate of return assumption for pension would result in an increase or decrease to the 2011 pension expense of approximately $2.9 million. A one percent change in the discount rate for pension would result in an increase or decrease to the 2011 pension expense of approximately $2.5 million. We do not anticipate any special adjustments to expense in 2011.

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

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

LEGAL AND OTHER MATTERS

A discussion of LEGAL AND OTHER MATTERS is described in Note 16 of Notes to Consolidated Financial Statements and in Item 3 — LEGAL PROCEEDINGS. A discussion of environmental matters and competition and regulation matters affecting both **DPL** and **DP&L** is described in Item 1 — ENVIRONMENTAL CONSIDERATIONS and Item 1 — COMPETITION AND REGULATION. Such discussions are incorporated by reference in this Management's Discussion and Analysis of Financial Condition and Results of Operations and made a part hereof.

Recently Issued Accounting Pronouncements

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

Item 7A — Quantitative and Qualitative Disclosures about Market Risk

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

Item 8 — Financial Statements and Supplementary Data

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

DPL INC.
CONSOLIDATED STATEMENTS OF RESULTS OF OPERATIONS

	For the years ended December 31,		
$ in millions except per share amounts	**2010**	**2009**	**2008**
Revenues	**$ 1,883.1**	$ 1,588.9	$ 1,601.6
Cost of revenues:			
Fuel	**383.9**	330.4	243.0
Purchased power	**387.4**	260.2	377.4
Total cost of revenues	**771.3**	590.6	620.4
Gross margin	**1,111.8**	998.3	981.2
Operating expenses:			
Operation and maintenance	**340.6**	306.5	282.5
Depreciation and amortization	**139.4**	145.5	137.7
General taxes	**127.4**	118.1	125.5
Total operating expenses	**607.4**	570.1	545.7
Operating income	**504.4**	428.2	435.5
Other income / (expense), net			
Investment income (loss)	**1.8**	(0.6)	3.6
Interest expense	**(70.6)**	(83.0)	(90.7)
Other income / (deductions)	**(2.3)**	(3.0)	(1.0)
Total other income / (expense), net	**(71.1)**	(86.6)	(88.1)
Earnings from continuing operations before income tax	**433.3**	341.6	347.4
Income tax expense	**143.0**	112.5	102.9
Net income	**$ 290.3**	$ 229.1	$ 244.5
Average number of common shares outstanding (millions):			
Basic	**115.6**	112.9	110.2
Diluted	**116.1**	114.2	115.4
Earnings per share of common stock:			
Basic	**$ 2.51**	$ 2.03	$ 2.22
Diluted	**$ 2.50**	$ 2.01	$ 2.12
Dividends paid per share of common stock	**$ 1.21**	$ 1.14	$ 1.10

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

$ in millions	For the years ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income	$ **290.3**	$ 229.1	$ 244.5
Adjustments to reconcile Net income to Net cash provided by operating activities:			
Depreciation and amortization	**139.4**	145.5	137.7
Deferred income taxes	**59.9**	201.6	43.1
Changes in certain assets and liabilities:			
Accounts receivable	**(1.5)**	39.3	(18.7)
Inventories	**10.4**	(20.6)	(0.2)
Prepaid taxes	**(9.0)**	—	—
Taxes applicable to subsequent years	**(4.1)**	(1.5)	(10.0)
Deferred regulatory costs, net	**16.0**	(24.6)	(12.9)
Accounts payable	**17.8**	(65.0)	27.0
Accrued taxes payable	**1.2**	(2.4)	(46.1)
Accrued interest payable	**(5.1)**	(1.5)	(0.8)
Pension, retiree and other benefits	**(58.2)**	15.2	31.2
Unamortized investment tax credit	**(2.8)**	(2.8)	(2.8)
Insurance and claims costs	**(6.1)**	(1.4)	(2.4)
Other	**16.0**	13.8	(28.4)
Net cash provided by operating activities	**464.2**	524.7	361.2
Cash flows from investing activities:			
Capital expenditures	**(152.7)**	(172.3)	(243.6)
Proceeds from sale of property - other	**—**	1.2	—
Purchases of short-term investments and securities	**(86.4)**	(20.7)	(39.1)
Sales of short-term investments and securities	**17.1**	25.7	34.2
Other investing activities, net	**1.4**	1.4	(4.4)
Net cash used for investing activities	**(220.6)**	(164.7)	(252.9)
Cash flows from financing activities:			
Dividends paid on common stock	**(139.7)**	(128.8)	(120.5)
Repurchase of DPL common stock	**(56.4)**	(64.4)	—
Repurchase of warrants	**—**	(25.2)	—
Proceeds from exercise of warrants	**—**	77.7	—
Reissuance of treasury stock	**—**	—	6.4
Retirement of long-term debt	**—**	(175.0)	(100.0)
Early redemption of Capital Trust II notes	**—**	(52.4)	—
Premium paid for early redemption of debt	**—**	(3.7)	—
Issuance of pollution control bonds, net	**—**	—	98.4
Retirement of pollution control bonds	**—**	—	(90.0)
Pollution control bond proceeds held in trust	**—**	—	(10.0)
Withdrawal of restricted funds held in trust, net	**—**	14.5	32.5
Withdrawals from revolving credit facilities	**—**	260.0	115.0
Repayment of borrowings from revolving credit facilities	**—**	(260.0)	(115.0)
Exercise of stock options	**1.4**	9.0	2.2
Tax impact related to exercise of stock options	**0.2**	0.7	0.3
Net cash used for financing activities	**(194.5)**	(347.6)	(180.7)
Cash and cash equivalents:			
Net change	**49.1**	12.4	(72.4)
Balance at beginning of period	**74.9**	62.5	134.9
Cash and cash equivalents at end of period	$ **124.0**	$ 74.9	$ 62.5
Supplemental cash flow information:			

Interest paid, net of amounts capitalized	$	**77.1**	$	84.3	$	86.8
Income taxes (refunded) / paid, net	$	**87.1**	$	(94.6)	$	127.3
Non-cash financing and investing activities:						
Accruals for capital expenditures	$	**23.2**	$	20.8	$	34.1

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	At December 31, 2010	At December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 124.0	$ 74.9
Short-term investments	69.3	—
Accounts receivable, net (Note 2)	215.5	212.8
Inventories (Note 2)	115.3	125.7
Taxes applicable to subsequent years	63.7	59.5
Other prepayments and current assets	40.6	24.1
Total current assets	628.4	497.0
Property, plant and equipment:		
Property, plant and equipment	5,353.6	5,269.2
Less: Accumulated depreciation and amortization	(2,555.2)	(2,466.0)
	2,798.4	2,803.2
Construction work in process	119.7	89.0
Total net property, plant and equipment	2,918.1	2,892.2
Other noncurrent assets:		
Regulatory assets (Note 3)	189.0	214.2
Other deferred assets	77.8	38.3
Total other noncurrent assets	266.8	252.5
Total Assets	$ 3,813.3	$ 3,641.7

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions			At December 31, 2010	2009
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Current portion - long-term debt (Note 5)			$ **297.5**	$ 100.6
Accounts payable			**98.7**	77.2
Accrued taxes			**68.1**	70.2
Accrued interest			**18.4**	23.5
Customer security deposits			**18.7**	19.4
Other current liabilities			**40.9**	24.0
Total current liabilities			**542.3**	314.9
Noncurrent liabilities:				
Long-term debt (Note 5)			**1,026.6**	1,223.5
Deferred taxes (Note 6)			**625.4**	569.1
Regulatory liabilities (Note 3)			**139.4**	125.4
Pension, retiree and other benefits			**64.9**	111.7
Unamortized investment tax credit			**32.4**	35.2
Insurance and claims costs			**10.1**	16.2
Other deferred credits			**130.8**	122.9
Total noncurrent liabilities			**2,029.6**	2,204.0
Redeemable preferred stock of subsidiary			**22.9**	22.9
Commitments and contingencies (Note 16)				
Common shareholders' equity:				
Common stock, at par value of $0.01 per share:				
	December 2010	**December 2009**		
Shares authorized	250,000,000	250,000,000		
Shares issued	163,724,211	163,724,211		
Shares outstanding	116,924,844	118,966,767	**1.2**	1.2
Warrants			**2.7**	2.9
Common stock held by employee plans			**(12.5)**	(19.3)
Accumulated other comprehensive loss			**(18.9)**	(29.0)
Retained earnings			**1,246.0**	1,144.1
Total common shareholders' equity			**1,218.5**	1,099.9
Total Liabilities and Shareholders' Equity			$ **3,813.3**	$ 3,641.7

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

in millions (except Outstanding Shares)	Common Stock (b) Outstanding Shares	Common Stock (b) Amount	Warrants	Common Stock Held by Employee Plans	Accumulated Other Comprehensive Income / (Loss)	Retained Earnings	Total
Beginning balance	113,558,444	$ 1.1	$ 50.0	$ (39.7)	$ 0.6	$ 870.5	$ 882.5
2008:							
Net income						244.5	
Change in unrealized gains (losses) on financial instruments, net of tax					(0.5)		
Change in deferred gains (losses) on cash flow hedges, net of tax					(1.7)		
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax					(21.5)		
Total comprehensive income							220.8
Common stock dividends (a)						(120.5)	(120.5)
Treasury stock reissued	2,403,436	0.1	(19.0)			21.2	2.3
Tax effects to equity						0.3	0.3
Employee / Director stock plans				12.1		(0.3)	11.8
Other						(0.1)	(0.1)
Ending balance	115,961,880	$ 1.2	$ 31.0	$ (27.6)	$ (23.1)	$ 1,015.6	$ 997.1
2009:							
Net income						229.1	
Change in unrealized gains (losses) on financial instruments, net of tax					0.5		
Change in deferred gains (losses) on cash flow hedges, net of tax					(3.7)		
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax					(2.7)		
Total comprehensive income							223.2
Common stock dividends (a)						(128.8)	(128.8)
Repurchase of warrants			(13.6)			(11.6)	(25.2)
Exercise of warrants	4,973,629		(14.5)			92.2	77.7
Treasury stock purchased	(2,388,391)					(64.4)	(64.4)
Treasury stock reissued	419,649					10.1	10.1
Tax effects to equity						0.8	0.8
Employee / Director stock plans				8.3		0.5	8.8
Other						0.6	0.6
Ending balance	118,966,767	$ 1.2	$ 2.9	$ (19.3)	$ (29.0)	$ 1,144.1	$ 1,099.9
2010:							
Net income						290.3	
Change in unrealized gains					0.4		

(losses) on financial instruments, net of tax							
Change in deferred gains (losses) on cash flow hedges, net of tax					6.4		
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax					3.3		
Total comprehensive income							300.4
Common stock dividends (a)						(139.7)	(139.7)
Repurchase of warrants			(0.2)				(0.2)
Exercise of warrants	18,288		—				—
Treasury stock purchased	(2,182,751)					(56.4)	(56.4)
Treasury stock reissued	122,540					2.4	2.4
Tax effects to equity						0.2	0.2
Employee / Director stock plans				6.8		5.1	11.9
Ending balance	116,924,844	$ 1.2	$ 2.7	$ (12.5)	$ (18.9)	$ 1,246.0	$ 1,218.5

(a) Common stock dividends per share were $1.10 in 2008, $1.14 in 2009 and $1.21 per share in 2010.

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

See Notes to Consolidated Financial Statements.