BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 16-0395-EL-SSO

CASE NO. 16-0397-EL-AAM

CASE NO. 16-0396-EL-ATA

2016 ELECTRIC SECURITY PLAN

VOLUME 7 OF 8 – TESTIMONY

WITNESSES MALINAK, MEEHAN, AND MILLER

Dayton Power and Light Company

DP&L Case No. 16-0395-EL-SSO

Table of Contents

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CASE NO. 16-0396-EL-ATA

CASE NO. 16-0397-EL-AAM

DIRECT TESTIMONY
OF R. JEFFREY MALINAK

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
- ■ **OTHER**

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DIRECT TESTIMONY OF

R. JEFFREY MALINAK

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is R. Jeffrey Malinak. I am currently a Managing Principal in the Washington, D.C. office of Analysis Group, Inc., a national economic and financial consulting services firm. My business address is 800 17th Street NW, Washington, DC 20006.

Q. What is the purpose of your testimony?

A. My testimony focuses on two topics:

- I analyze the financial condition and integrity of both the coal-fired generating assets that would be covered under the Reliable Electricity Rider ("RER") and DPL Inc. (also "Company"), the parent company of The Dayton Power and Light Company ("DP&L").[1] I perform this analysis under two different assumptions regarding the revenues that the coal-fired generating assets would earn under two different rate regimes: (a) a Market Rate Offer (MRO), in which the assets' revenue would be based on unregulated market rates, and (b) an Electric Security Plan (ESP) with the proposed RER.

- I evaluate whether the proposed ESP in this case is "more favorable in the aggregate" than the expected results from an MRO.

[1] DP&L's generating assets consist primarily of partial interests in five coal-fired power plants, which are co-owned by Dynegy and AEP. I understand that the revenues and costs of these plants, including Fuel, Capital and Operations and Maintenance ("O&M") costs, are allocated on a pro-rata basis to each of the owners. The proposed RER will apply to DP&L's interests in these five plants, plus a pro-rata portion of the Ohio Valley Electric Corporation ("OVEC") coal-fired generation facilities. I refer to these DP&L interests in coal-fired facilities as the "coal-fired generating assets" or "fleet."

Q. What is your educational and work background?

A. I have over 25 years of experience in the field of economic and financial consulting, in which I have provided microeconomic, finance and accounting consulting advice and other services to attorneys and companies in both litigation and non-litigation settings. My main areas of expertise are financial economics and valuation of corporations and other assets. I spent approximately seven years of my career at Putnam, Hayes & Bartlett, Inc. (PHB), an economic and financial consulting firm with large consulting practices in the energy industry and other regulated industries. While at PHB, approximately half of my time was spent on litigation matters and regulatory proceedings, including rate cases, in the electric utility and energy sectors. My work on these matters included revenue requirements modeling; analysis of the economics of coal mining and transportation; analysis of the operations and economics of nuclear, coal, wood scrap and natural gas power plants; forecasting of load and related generation capacity requirements; assessment of the cost of capital for generation and for transmission and distribution (both electric and natural gas); calculation of the cost of compliance with environmental regulations; modeling and forecasting of emission allowance prices; and other topics. Since joining Analysis Group in the mid-1990s, I have continued to work on projects in the energy and environmental economics areas, including regulatory matters.

I hold a Master's in Business Administration in Finance and Accounting from the University of Texas at Austin and a B.A. in Social Sciences from Stanford University. My resume, which is included as Appendix A, provides more details on my background and prior experience.

Q. Have you previously testified before the Public Utilities Commission of Ohio?

A. Yes. I testified on behalf of DP&L in Case No. 12-426-EL-SSO.

Q. How does your experience relate to your testimony in this proceeding?

A. As noted above, I testified before the PUCO in Case No. 12-426-EL-SSO et al. My testimony in that case focused on the more favorable in the aggregate test, which is one of the two issues I address here. Also in that case, I worked in a consulting capacity to provide support to Dr. William Chambers, who provided testimony on the financial integrity and financial condition of DP&L. I also provided rebuttal testimony on these latter two issues. More generally, I have substantial prior experience with analysis of economic and financial issues in the energy sector, and with the analysis of the economic impact of different rate regimes on a variety of stakeholders, including customers.

II. SUMMARY OF MAIN CONCLUSIONS

Q. Please summarize the main conclusions that you have reached regarding the near-term financial condition and integrity of the coal-fired generating assets and DPL Inc. under an MRO.[2]

A. [redacted]

[2] I define the terms "financial condition" and "financial integrity" later in this testimony.

Q. What are your bases for this conclusion?

A. [redacted]

Q. Are there any other bases for your conclusion regarding DPL Inc.'s lowered financial integrity under an MRO?

A. [redacted]

[3] Credit Agreement among DPL Inc., U.S Bank National Association, PNC Bank, National Association, and Bank of America, N.A., July 31, 2015, at 94-95.

Q. Please summarize the main conclusions that you have reached regarding the <u>longer-term</u> financial condition of the coal-fired generating assets and DPL Inc. under an MRO.

A. [redacted]

Q. Why can't DPL Inc. take advantage of these favorable projections today by, for example, borrowing against the coal-fired generating assets at reasonable rates?

A. [redacted]

[4] The dark spread is the gross margin of a coal-fired generating plant—the difference between per unit cost necessary to generate energy and the per unit price of which that energy can be sold.

Q. Please summarize the main conclusions that you have reached regarding the <u>near-term</u> financial condition of the coal-fired generating assets and DPL Inc. under the proposed ESP with an RER.

A. [redacted]

[redacted]

Q. Please summarize the main conclusions that you have reached regarding the <u>longer-term</u> financial condition of the coal-fired generating assets and DPL Inc. under the proposed ESP with an RER.

A. [redacted]

Q. Can you summarize the overall results and their general implications?

A. [redacted]

Q. Please summarize your conclusions regarding the "more favorable in the aggregate" test.

A. I conclude that the ESP, with the RER proposed by DP&L, would be more favorable in the aggregate to customers than an MRO. First, based on the baseline PJM market energy and capacity prices projected by Mr. Meehan, the RER would result in a net quantitative financial benefit to customers. Specifically, in nominal terms, the projected RER would result in a $455 million reduction in the customers' electricity costs between 2017 and 2026. In present value terms, the benefit to customers ranges from $61 million to $272 million, depending on the discount rate that is applied. Second, the ESP would improve the combined Company's ability to make the investments necessary to provide safe and reliable electric service, while also meeting financial obligations to the creditors of

DP&L and DPL Inc. As a result, the ESP provides for a more robust energy market than would occur under an MRO. Third, DP&L-TD's customers would likely receive more stable energy prices, particularly during extreme conditions such as the Polar Vortex that affected the service area in 2014. Finally, to the extent that the RER reduces the probability that the coal-fired generating assets at issue will be retired, the ESP reduces the risk of substantial direct and indirect costs for DP&L customers and the surrounding area in the form of (a) a loss of jobs, a loss of tax revenues, an increase in electricity prices for the state and a drop in disposable income for Ohio consumers and businesses and (b) increased transmission investments that would be necessary for a reliable electric grid. For these and other reasons discussed below, the ESP with the proposed RER is more favorable in the aggregate for DP&L customers than an MRO.

Q. Please identify the Exhibits attached to your testimony.

A. The attached exhibits are as follows:

- Exhibit RJM-1: DPL Inc. projected financial ratios without RER;
- Exhibit RJM-2: DPL Inc. projected financial information without RER;
- Exhibit RJM-3: DPL Inc. projected financial ratios with RER;
- Exhibit RJM-4: DPL Inc. projected financial information with RER;
- Exhibit RJM-5: Moody's credit rating tables for regulated utilities and unregulated power companies;
- Exhibit RJM-6: Projected financial statements for DPL Inc. without RER;
- Exhibit RJM-7: Projected financial statements for DPL Inc. with RER;
- Exhibit RJM-8: Projected income from operations for the coal-fired generating assets;
- Exhibit RJM-9: Calculation of the RER;
- Exhibit RJM-10: Analysis for the RER;
- Exhibit RJM-11: Debt service analysis without RER;
- Exhibit RJM-12: Debt service analysis with RER;

- Exhibit RJM-13: Summary of DPL Inc. and DP&L-TD debt; and
- Exhibit RJM-14: Test ratings model.

The body of this report also contains a number of figures that summarize information from those exhibits and other relevant sources. All of these exhibits are part of my analysis and are either referred to in the text, another exhibit or otherwise relied upon.

III. FINANCIAL CONDITION AND INTEGRITY OF THE COAL-FIRED GENERATING ASSETS AND DPL INC.

A. INTRODUCTION

Q. What do you mean by the terms "financial condition" and "financial integrity?"

A. I use the term "financial condition" to refer to an assessment of the general financial health based on a variety of financial variables ranging from income statement items such as revenue growth, profitability and cash flow, to balance sheet items such as the amount of liquid assets, amount and types of liabilities, debt-to-capital ratios and other financial ratios.

I use the term "financial integrity" to refer more specifically to an assessment of the likelihood of default or bankruptcy, i.e., a credit-risk assessment. Thus, one cannot assess the financial integrity of an entity or enterprise without also analyzing its financial condition. For example, as I use the term, poor financial performance (e.g., low profitability) is an indicator of poor financial condition, which will reduce financial integrity, all else equal.

Q. Why do you analyze the financial condition and integrity of the coal-fired generating assets and DPL Inc.?

A. In its rulings in Case Nos. 13-2385-EL-SSO and 14-841-EL-SSO, the PUCO identified the financial need of the generating plant as one of nine factors that it will consider in deciding whether to approve a proposal such as the proposed ESP in this case, with the RER.[5] In this case, the RER will apply to the coal-fired generating assets. The financial performance of these assets has a direct and critical impact on DPL Inc.'s financial condition and ultimate financial integrity, and has an indirect impact on DP&L-TD as well. Thus, I analyze and compare the financial performance of the coal-fired generating assets under an MRO versus under an ESP with the RER, and the effect that this performance will have on the financial condition and integrity of DPL Inc.

Q. How does the financial condition and integrity of the coal-fired generation assets and DPL Inc. affect DP&L-TD?

A. [redacted]

[5] Public Utilities Commission of Ohio, Opinion and Order, Case No. 13-2385-EL-SSO, February 25, 2015, at 25-26; Public Utilities Commission of Ohio, Opinion and Order, Case No. 14-841-EL-SSO, April 2, 2015, at 47.

[redacted]

Q. Please describe the approach that you take to measuring and analyzing how the financial condition of DP&L's coal-fired generating assets affects the financial integrity of DPL Inc.

A. DP&L's coal-fired generating assets currently are part of the integrated firm, along with its transmission and distribution ("T&D") assets. The two businesses are currently functionally separated and are scheduled to be legally separated by January 1, 2017. From a financial perspective, both before and after the legal separation, the coal-fired generating and T&D assets are (will be) owned by DPL Inc.[7]

[redacted]

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[6] Fitch notes that it "has constrained DP&L's rating based on its ownership by a weak parent and lack of explicit ring fencing provisions. Any further downward action in DPL's rating could result in commensurate downward ratings actions for DP&L." Fitch Ratings, "DPL Inc. and Dayton Power & Light Company," October 7, 2014, at 1.

[7] I will refer to DP&L's T&D assets after separation as "DP&L-TD."

[8] DPL Inc. would depend to a lesser extent on cash flow from its smaller subsidiaries such as DPLE, MVLT, and MVIC. For example, Moody's notes that DP&L (including the generating assets) "is expected to remain the main

(footnote cont'd…)

[redacted]

(…cont'd)
source of cash flows to service its material amount of holding-company's indebtedness." That is, not the miscellaneous subsidiaries. Moody's Investors Service, "Credit Opinion: DPL Inc.," October 13, 2015.

[9] The term "free cash flow" means net cash flow remaining after payment of all cash costs, including debt service and capital expenditures.

Q. What are DPL Inc.'s options for servicing its debt other than using cash flow from its coal-fired generating assets?

A. [redacted]

Q. Is there additional support for this "integrated" approach?

A. Yes. My approach is consistent with the Commission's previous adoption of an integrated view of financial condition and integrity. Specifically, in approving the Service Stability Rider ("SSR") in DP&L's prior ESP filing, the Commission stated that, "if one

[10] For example, Moody's notes that DP&L (including its coal-fired generating assets) "is expected to remain the main source of cash flows to service its material amount of holding-company's indebtedness." That is, not the miscellaneous subsidiaries. Moody's Investors Service, "Credit Opinion: DPL Inc.," October 13, 2015. Moody's observation is consistent with my own analysis as discussed later in my testimony.

of the businesses suffers from financial losses, it may impact the entire utility, adversely affecting its ability to provide stable, reliable, or safe retail electric service."[11]

Similarly, in the same case, the PUCO rejected intervenors' argument that "competitive generation assets … are not necessary for DP&L to maintain reliable distribution and transmission service."[12] Also in the same case, the PUCO stated that, "As the Commission has previously noted, the SSR and SSR-E are financial integrity charges intended to maintain the financial integrity of the entire company, not just the generation business. Order at 21-22; Second Entry on Rehearing at 3. Therefore, when DP&L does, in fact, divest the generating assets, it does not necessarily follow that the SSR or the SSR-E must end."[13] Thus, while the generating assets were not structurally separated from the regulated utility at the time of that ruling, as discussed above, the financial condition and integrity of DPL Inc. could have an impact on DP&L-TD.

Q. Please describe how the remainder of this section will be structured.

A. I begin immediately below with a description of the DP&L's service territory, its coal-fired generating assets and the economic environment in which they are operating. This description provides useful background and context for my financial analysis. Next, I provide a discussion of my methodology for analyzing the financial condition and integrity of the coal-fired generating assets and DPL Inc., followed by a discussion of the

[11] Public Utilities Commission of Ohio, Case No. 12-426-EL-SSO, Opinion and Order, September 4, 2013, at 22. Public Utilities Commission of Ohio, Case No. 12-426-EL-SSO, Fourth Entry on Rehearing, June 4, 2014, at 9.
[12] Public Utilities Commission of Ohio, Case No. 12-426-EL-SSO, Opinion and Order, September 4, 2013, at 18, 22.
[13] Public Utilities Commission of Ohio, Case No. 12-426-EL-SSO, Fourth Entry on Rehearing, June 4, 2014, at 9.

inputs to my financial projections under an MRO and ESP with RER. The results of these projections are described at the end of the section.

B. DP&L'S COAL-FIRED GENERATING ASSETS AND THE ECONOMIC ENVIRONMENT

Q. Please describe DP&L's service area.

A. DP&L serves over 515,000 customers in 24 counties throughout the Miami Valley in West Central Ohio.[14] The service area comprises the majority of 13 counties surrounding Dayton and portions of an additional 11 counties.[15] According to the U.S. Census, the total population of the 13-county primary area was approximately 1.24 million in 2014, virtually unchanged from the 2010 figure.

Income levels of the service area population were close to the state average. U.S. Census data indicate that average per capita income between 2010 and 2014 was $24,817 in the 13-county primary area, as compared with the state average of $26,520. On a per household basis, the median household income for the state was $48,849, lower than the $50,073 for the 13 county primary area. Thus, on an ability-to-pay basis, the population of the DP&L service area appears to be similar to that of the remainder of Ohio. In a like vein, the unemployment rate for November 2015 showed that Montgomery County was slightly above the state average of 4.6 percent, while the other 12 counties in the 13-county primary area were all below the state average, according to the Bureau of Labor Statistics.

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[14] http://www.dpandl.com/about-dpl/who-we-are/the-basics/; http://www.dpandl.com/about-dpl/who-we-are/economic-development/.

[15] http://www.dpandl.com/about-dpl/who-we-are/economic-development/; The 13 counties include Mercer County, Auglaize County, Darke County, Shelby County, Miami County, Logan County, Champaign County, Union County, Preble County, Montgomery County, Green County, Fayette County, and Clinton County.

Q. What is the economic outlook for DP&L's service area?

A. The economy of the Dayton area has seen steady recovery since 2010 in jobs, unemployment, and output. However, the region has been slower to recover than many of the other U.S. metropolitan areas and the whole nation.[16] Moody's views the stability from Wright-Patterson AFB and local universities, quality healthcare system that serves the local population and the surrounding region, and well-developed manufacturing infrastructure as the strengths of Dayton. The low education attainment of the workforce, persistent out-migration and the sluggish housing market are considered to be the weaknesses of its economy.[17] The Brookings Institution's Metro Monitor shows Dayton as ranked 79th in overall economy growth, 86th in job growth, 61st in gross metropolitan product growth and 92nd in aggregate wages growth, out of the 100 largest U.S. metropolitan areas over the last five-year period.[18] DP&L operates in a manufacturing-oriented region, and, as a result, a large part of its load comes from industrial and commercial customers, who tend to be relatively price sensitive. [19]

Q. What generating assets are included your analysis?

A. As explained by Company Witness Miller, the coal-fired generation plants are the following:

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[16] http://www.daytondailynews.com/news/news/daytons-economy-inching-along-report-says/nmgNZ/; http://www.brookings.edu/research/interactives/metromonitor#/M19380.
[17] https://www.economy.com/metro/precis-snapshot.aspx?g=MDAY.
[18] http://www.brookings.edu/research/reports2/2016/01/metro-monitor#V0G19380.
[19] https://www.economy.com/metro/precis-snapshot.aspx?g=MDAY.

	Ownership (percent)	Summer Capacity (MW)	Gross Plant in Service ($ mil.)	Net Plant in Service ($ mil.)
Coal-fired generating fleet				
Conesville Unit #4	17	129	20.5	16.0
Killen Unit #2	67	402	659.3	334.2
Miami Fort Units #7 & 8	36	368	369.8	201.0
Stuart Units #1-4*	35	808	802.0	465.0
Zimmer Unit #1	28	371	1,121.8	732.6
OVEC	5	103		
Total		*2,181*	*2,973.4*	*1,748.8*

* Includes diesel.

Q. What are the key factors affecting the economics of unregulated coal-fired electric power plants in the United States and Ohio?

A. There are currently three key factors that are negatively affecting unregulated coal plant operations in the United States and Ohio. First, historic low natural gas prices have put downward pressure on dark spreads and allowed gas combined-cycle power plants to increase their production at the expense of coal generation. Second, volatile prices in the PJM capacity auctions, as well as the forthcoming changes in the PJM capacity auction rules, have led to high uncertainty about the revenue streams to generating assets. Third, future environmental regulations might require substantial additional investments.

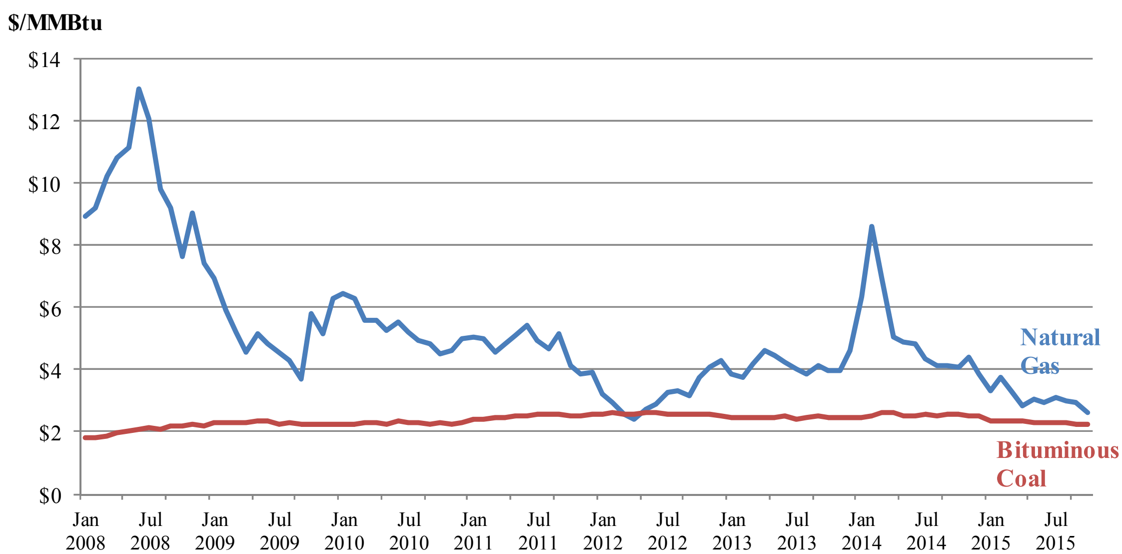
Q. How do low natural gas prices affect coal-fired power generating plants?

A. The shale oil extraction boom in the United States has caused a surge in the production of natural gas. That has led to a significant decline in the natural gas prices, while the price of coal has remained relatively stable.

Figure 1 summarizes natural gas and bituminous coal prices per million British thermal unit (MMBtu) in the East North Central region of the United States. The price of natural gas dropped to $2.62 per MMBtu in October 2015. This is a nearly 70 percent decrease relative to the February 2014 spike of $8.61 per MMBtu and a nearly 80 percent decrease relative to the historic high of $13 per MMBtu in June 2008.

FIGURE 1

AVERAGE COST OF FUELS FOR ELECTRICITY GENERATION
EAST NORTH CENTRAL REGION



Notes & Sources:
Data from the U.S. Energy Information Administration.

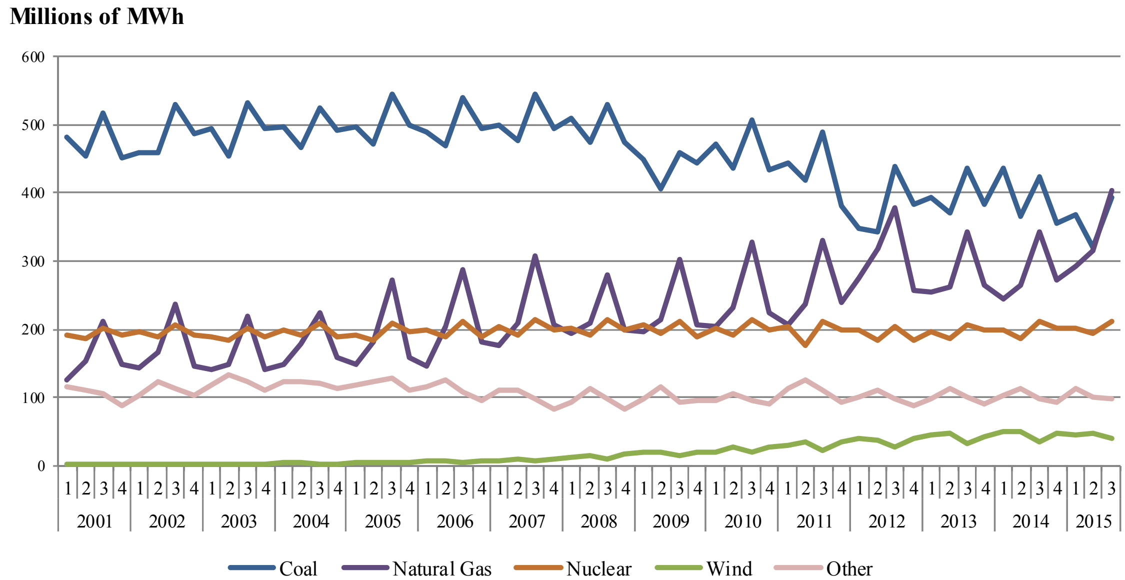
These unusually low natural gas prices have had a significant adverse effect on coal-fired power plant revenues due to both price and quantity effects. First, low gas prices tend to result in lower generation output for coal-fired plants because PJM dispatching is based primarily on marginal costs. When natural gas prices fall far enough, the highest-efficiency combined-cycle gas-fired units in PJM will be dispatched ahead of coal-fired units. The "first-dispatched" wind and solar energy and increased dispatch of gas-fired generation mean that coal-fired units that traditionally ran 24 hours a day as base load units are often dispatched for fewer hours during the day. Second, lower gas prices also tend to lower energy prices, which often results in a reduction in dark spreads. The dark spread, or the difference between price at which a unit of energy can be sold and the cost necessary to generate that energy, represents the margin a coal-fired generating plant earns on energy. As natural gas prices fall, dark spreads compress and reduce revenue from energy sales for coal plants.

Q. Please describe the role of coal-fueled plants relative to other sources of power over time.

A. For years, coal-fueled generation was the major source of electric power in the United States. The following graph shows that until 2009, coal generation plants provided around 500 million MWh of electric power. Later, the share of natural gas and wind gradually started to increase and gas surpassed coal as the leading fuel source in the third quarter of 2015.

FIGURE 2

**NET GENERATION OF ELECTRIC POWER
UNITED STATES**

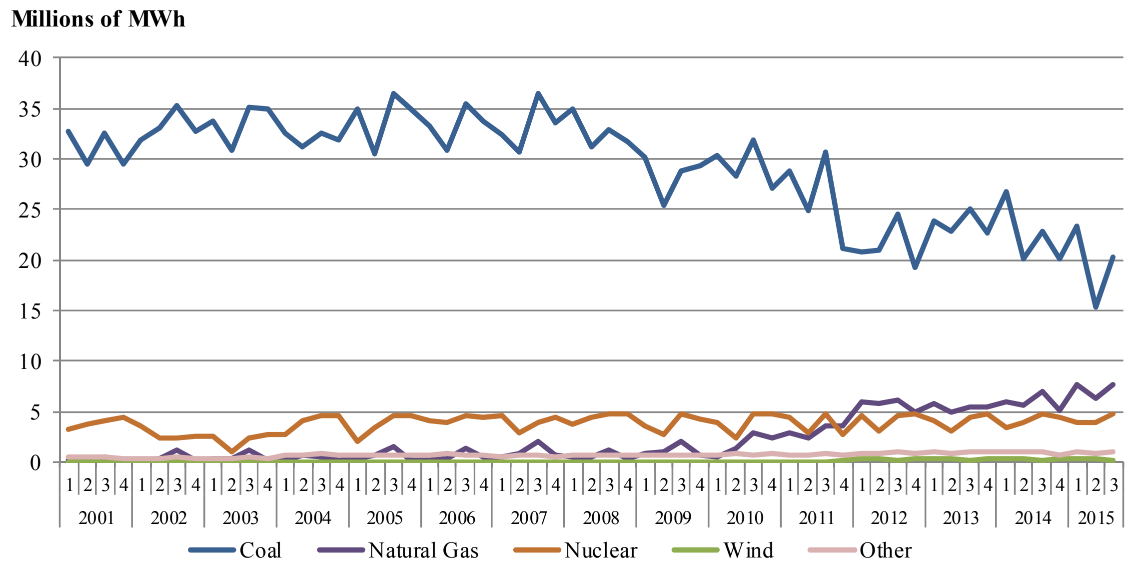


Notes & Sources:
Data from the U.S. Energy Information Administration.

Power generators in Ohio have historically been less reliant on natural gas than generators in other parts of the country. Before 2010, natural gas generation in Ohio was usually limited to peak summer demand. Since 2010, natural gas-fueled power plants have produced significantly higher amounts of power during all seasons. As is the case with the United States as a whole, the increase in natural gas generation has largely displaced coal-fueled generation.

FIGURE 3

NET GENERATION OF ELECTRIC POWER
OHIO



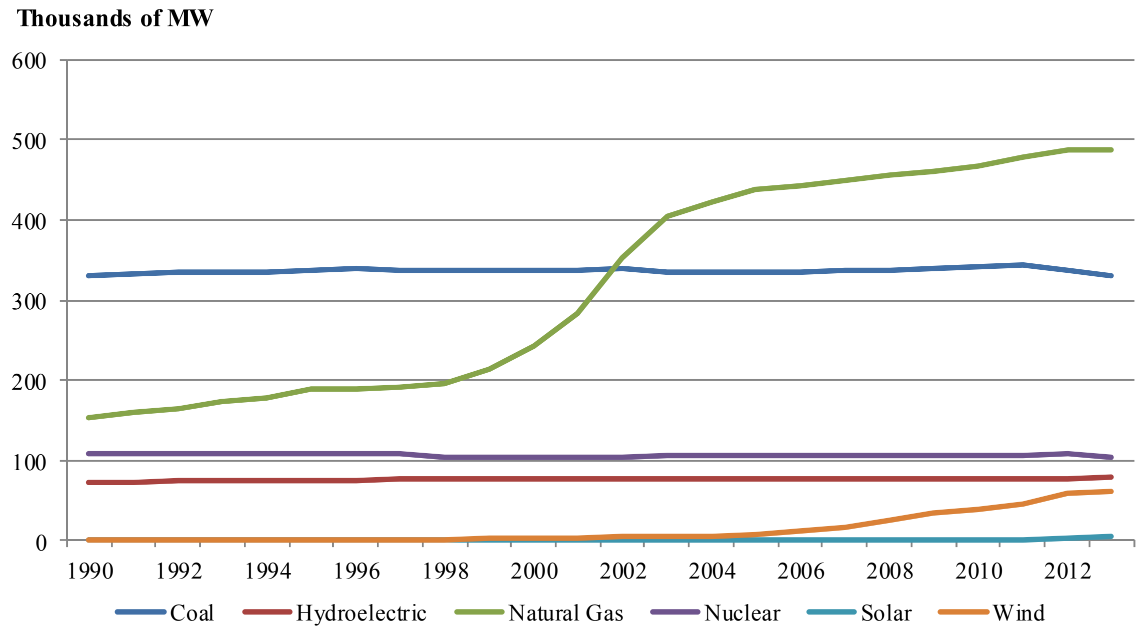
Notes & Sources:
Data from the U.S. Energy Information Administration.

Q. What are some of the consequences of these trends?

A. Two significant consequences have been an increase in the retirements of coal generation capacity, coupled with a greatly reduced share of new capacity. Figure 4 shows that coal-fired generation capacity in the U.S. started to decline in 2011, while natural gas capacity has increased significantly since 1998, such that it now significantly exceeds coal capacity. Both nuclear and hydroelectric generation have remained static. This same general trend can be observed in the PJM region, as shown in Figure 5.

FIGURE 4

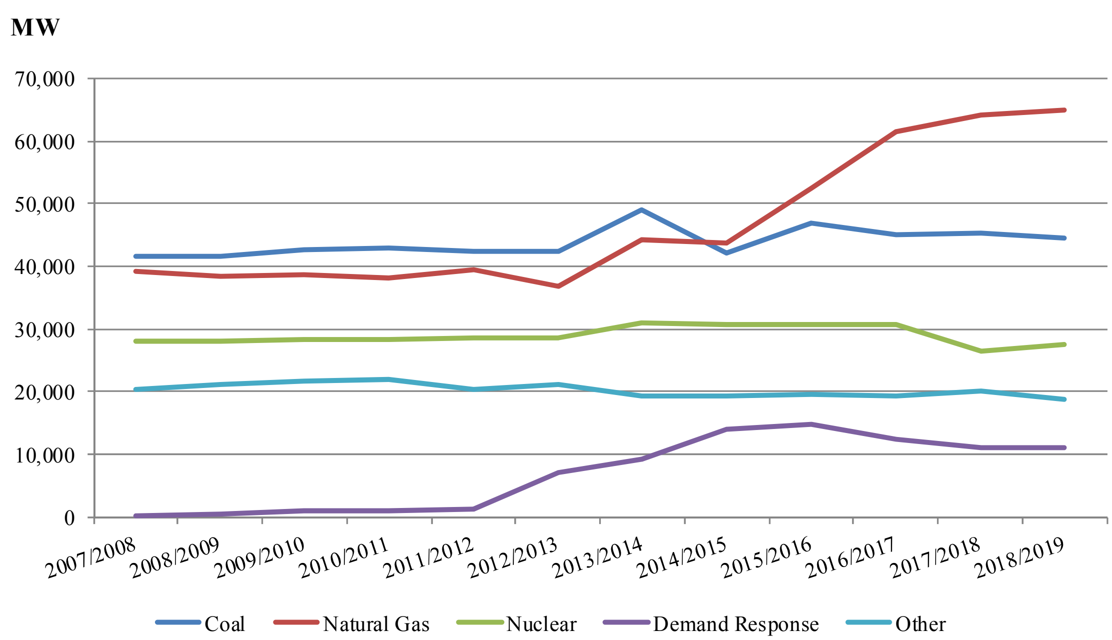
TOTAL NAMEPLATE CAPACITY
UNITED STATES



Notes & Sources:
Data from the U.S. Energy Information Administration.

FIGURE 5

PJM UCAP CLEARED CAPACITY COMMITMENTS BY FUEL TYPE



Notes & Sources:
Data from PJM.

Q. How do volatile capacity prices and the forthcoming changes in the PJM capacity auction rules affect the economics of the at-issue coal plants?

A. As described in the testimony of Company Witness Jackson, capacity prices in PJM have been particularly volatile recently. This volatility, when combined with the other trends discussed above, leads him to conclude that, "… without this predictability [of future cash flow], it is fiscally irresponsible … to make significant required investments in the generation business."[20] Indeed, this volatility makes coal-fueled generators particularly vulnerable because their earnings largely depend on the capacity revenues. DP&L noted the pressure that lower capacity prices might have and the risks stemming from the proposed changes to the design of the Reliability Pricing Model.[21] In particular, DP&L previously estimated that a $10 per MW-Day change in the capacity auction price would lead to a $7 million change in annual net income.[22]

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[20] Direct Testimony of Craig L. Jackson, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM, at 15.

[21] DP&L informs its investors of the pending modifications of the design of the Reliability Pricing Model as follows, "There are proposals from PJM pending before the FERC that would modify capacity markets including near-term modifications with respect to RPM and longer term modifications that would phase out RPM and replace it with a Capacity Performance ("CP") program. The final form of CP program has not been established and the effects on DP&L cannot be predicted. In concept, however, the CP program is intended to result in higher capacity prices paid to generators, paired with larger penalties for a generator's failure to perform during periods where electricity is in high demand. Future RPM or CP auction results will be dependent not only on the overall supply and demand of generation and load, but may also be affected by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the capacity auctions. Increases in customer switching causes more of the capacity costs and revenues to be excluded from the DP&L's Ohio RPM rider calculation. We cannot predict the outcome of future auctions or customer switching but if the current auction price is not sustained or if higher penalties are incurred due to implementation of the CP program and DP&L's generation performance, it could have a material adverse effect on our future results of operations, financial condition and cash flows." DPL Inc. and DP&L FY14 Form 10-K for the fiscal year ended December 31, 2014, at 15.

[22] DPL Inc. and DP&L FY15 Form 10-Q for the quarterly period ended September 30, 2015, at 89.

The replacement of the Reliability Pricing Model with the Capacity Performance program might result in higher capacity prices for generators but could also lead to larger penalties for a generator's failure to perform during periods where electricity is in high demand.

It should also be reiterated that the volatility in the capacity markets and associated uncertainty around future cash flow streams, makes it challenging for standalone coal generation companies to raise short or long term debt at reasonable prices.

Q. Are there other factors that present risk for coal-fueled generation?

A. Yes. Environmental regulations also present a significant risk to generation plants, particularly coal-fired plants. Any change to the regulatory framework regarding environmental compliance might require significant investments and could depress future earnings and/or force early retirements.[23]

According to the projections made by the U.S. Energy Information Administration, 40 GW of coal capacity will be retired from 2013 to 2040. These retirements include announced retirements and those projected based on relative economics, including the

[23] For example, DP&L informs its investors of this risk as follows, "There is an ongoing concern nationally and internationally among regulators, investors and others concerning global climate change and the contribution of emissions of GHGs, including most significantly CO2. This concern has led to interest in legislation and action at the international, federal, state and regional levels, including regulation of GHG emissions by the USEPA, and litigation seeking to compel the promulgation or enforcement of GHG requirements. Approximately 99% of the energy we produce is generated by coal. As a result of current or future legislation or regulations at the international, federal, state or regional levels imposing mandatory reductions of CO2 and other GHGs on generation facilities, we could be required to make large additional capital investments and/or incur substantial costs in the form of taxes or emissions allowances. Such legislation and regulations could also impair the value of our generation stations or make some of these stations uneconomical to maintain or operate and could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing generation stations. Although DP&L is permitted under its current ESP to seek recovery of costs associated with new climate change or GHG 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." DPL Inc. and DP&L FY14 Form 10-K for the fiscal year ended December 31, 2014, at 20.

costs of meeting environmental regulations and competition with natural gas-fired generation in the near term. Because of the uncertainty surrounding future greenhouse gas legislation and regulations and given its high capital costs, very little unplanned coal-fired capacity will be added.[24]

Q. What has been the impact on coal-fired generation capacity in the state of Ohio?

A. As described in the testimony of Company Witness Craig Jackson, over 6,000 MW of capacity, most of which was coal-fired, have been retired in Ohio since 2011.[25]

C. METHODOLOGY

Q. Please summarize the nature of the financial analysis that you are sponsoring.

A. My primary assignment is to analyze the financial condition of DP&L's coal-fired generating assets under an MRO versus the proposed ESP and RER. As discussed previously, DPL Inc. will depend heavily on its coal-fired generating assets to service its debt. Thus, DPL Inc.'s financial integrity is largely dependent on the financial integrity of the generating assets. As a result, I focus on evaluating the financial condition and needs of DPL Inc. over the short and long term. In addition, after separation, DP&L's coal-fired generating assets and DP&L-TD will remain intertwined through their common ownership by DPL Inc., and DP&L-TD's financial and operational performance will be affected indirectly by the health of DPL Inc. and the generating assets; thus, my evaluation of DPL Inc. necessarily includes consideration of the impact on DP&L-TD as well.

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[24] EIA April 2015 "Annual Energy Outlook 2015 with projections to 2040."
[25] Direct Testimony of Craig L. Jackson, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM, at 12.

The core methodology that I use is to analyze financial data from financial projections for 2017 through 2026 based on an integrated financial model I developed that includes all of DPL Inc.'s businesses, assets and liabilities. Integrated financial models include balance sheets, income statements, and cash flow statements, all of which are linked with each other in some fashion. For example, balance sheet equity is reduced or increased each year by after-tax net income from the income statement. In a similar fashion, changes in certain balance sheet accounts, such as increases and decreases in accounts receivable, affect the cash flow statement. Use of such an integrated modeling approach provides checks and balances so that financial projections are internally consistent.

Based on projections for the coal-fired generating assets and DPL Inc. using this integrated model, I am able to calculate various financial metrics for these entities, which are based on income, balance sheet and cash flow statement variables. These metrics allow me to draw conclusions about financial condition and integrity of each entity over time.

Q. Please describe how you apply this methodology to DPL Inc.

A. I combine the financial projections for the coal-fired generating assets, DP&L-TD and other parts of DPL Inc. to obtain projected consolidated financial statements for DPL Inc. Projected excess cash flows from the various businesses can be used to pay down debt at DPL Inc. and DP&L-TD until it has met its targeted capital structure.. [26]

[26] In the model of the ESP with the RER, I adopt the same debt refinancing and retirement assumptions used by Company Witness Craig Jackson. In the model of the MRO, I modify the assumptions about voluntary debt retirement to use instead amounts equal the available cash flows. Specifically, I assume that net cash flows from DPL Inc.'s subsidiaries are used to meet debt service obligations first, after which any excess is then used to pay

(footnote cont'd…)

Q. Please describe the debt held by DPL Inc. and DP&L.

A. As shown in Exhibit RJM-13, DPL Inc. had approximately $1.25 billion in outstanding debt at the end of 2015, composed of a $125 million Term Loan, $330 million in Bonds maturing in 2016 and 2019, $780 million in Bonds maturing in 2021 and $16 million in a Capital Trust. DP&L had approximately $0.76 billion in outstanding debt, including $445 million in 2003 First Mortgage Bonds (to be refinanced in 2016), $100 million in 2006 Ohio Air Quality Bonds, $200 million in Ohio Air Quality VRDNs and an $18.1 million Purchase Note.

Both DPL Inc. and DP&L-TD have financial covenants related to their debt, including Debt/EBITDA, EBITDA/Interest, and Debt/Total Capital as summarized below.[27]

	Max. Debt/ EBITDA	Min. EBITDA/Interest		Max. Debt/Capital
Year	DPL Inc.	DPL Inc.	DP&L-TD	DP&L-TD
2017	7.25	2.10	2.50	0.75
2018	7.25	2.10	2.50	0.75
2019	6.25	2.25	2.50	0.75
2020	5.75	2.25	2.50	0.75

When DPL Inc. is facing challenges in servicing its debt, it will have to choose to (a) issue new debt, either through drawing on its short term debt instruments or otherwise raising new debt or (b) reduce capital investments at any of its subsidiaries in order to increase distributable cash flows, or (c) cut costs or undertake other actions to generate

(…cont'd)
debt down at DPL-TD until it meets its required 50/50 capital structure target, and finally to reduce DPL Inc.'s long-term debt.

[27] Credit Agreement among DPL Inc., U.S Bank National Association, PNC Bank, National Association, and Bank of America, N.A., July 31, 2015, at 94-95; Credit Agreement among Dayton Power and Light Company, PNC Bank, National Association, Fifth Third Bank, and Bank Of America, N.A., July 31, 2015, at 79.

additional cash. As discussed above, both (a) and (b) are particularly problematic. This appears to be particularly true with respect to capital expenditures on DP&L's generating assets, which Fitch describes as being the "bare minimum."[28] Indeed, Company Witness Miller notes that, "DP&L has been stretched financially in its ability to fund investment beyond the minimum necessary to keep its units running."[29]

Q. What financial metrics do you use to evaluate the financial condition and financial integrity of the coal-fueled generating assets and DPL, Inc.?

A. One financial metric I consider for measuring the financial condition of the coal-fueled generating assets is Return on Equity (ROE). For DPL Inc., and for the purposes of measuring financial integrity, I also consider (a) free cash flow metrics (b) certain credit metrics, including Interest Coverage, Cash Flow / Debt, Retained Cash Flow / Debt, and Debt / Capital (each as defined below), and (c) the theoretical credit rating and any changes thereof. Credit ratings are a summary measure of financial integrity, and are based on a number of the financial metrics discussed, as well as the professional judgment of the debt rating agencies.

Q. What are the corporate credit ratings for DPL Inc. and DP&L?

A. The most recent credit rating reports from Moody's for DPL Inc. and DP&L are from October 13, 2015. At that time, Moody's rated DPL Inc. "Ba3" (equivalent to S&P rating "BB-") and rated DP&L "Baa3" (equivalent to S&P rating "BBB-"), both with a stable

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[28] Fitch Ratings, "DPL Inc. and Dayton Power & Light Company," October 7, 2014, p. 2. Fitch's comment is a bit unclear, but appears to refer to DP&L's recent capital expenditures on its coal-fired generating assets (referencing "the anticipated transfer of these assets to a nonregulated affiliate.")
[29] Direct Testimony of Mark E. Miller, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM, at 5.

outlook, and noted that DPL Inc.'s rating "is based on the expectation that DP&L will be able to record cash flow metrics that are robust for the Baa-rating category."[30] The ratings from Fitch and S&P are similar: DPL Inc. is currently rated "B+" by Fitch and "BB" by S&P.[31] DP&L is rated "BB+" by Fitch and "BB" by S&P.[32] Of note, these ratings are for a period in which the $110 million SSR will continue through 2016 and depend on several key assumptions including, for example, in Moody's case, an "Overall constructive regulatory environment albeit some uncertainty prevails beyond the tenor of DP&L's ESP II."[33]

	DPL Inc.	DP&L
Moody's (S&P scale)	BB-	BBB-
Fitch	B+	BB+
S&P	BB	BB

Q. How did you determine indicated credit ratings for DPL Inc.?

A. I have created financial projections for 2017 through 2026 for DPL Inc. From those projections, I calculate four key metrics that Moody's uses to determine credit ratings for DPL Inc. and other energy companies:[34]

1. *Interest Coverage*
2. *Cash Flow / Debt*
3. *Retained Cash Flow / Debt*
4. *Debt / Capital*

[30] Moody's Investors Service, Credit Opinion: DPL Inc., October 13, 2015; Moody's Investors Service, Credit Opinion: Dayton Power & Light Company, October 13, 2015.
[31] SNL Energy.
[32] SNL Energy.
[33] Moody's Investors Service, Credit Opinion: DPL Inc., October 13, 2015; Moody's Investors Service, Credit Opinion: Dayton Power & Light Company, October 13, 2015.
[34] *See, e.g.*, Moody's Investors Service, Credit Opinion: DPL Inc., October 13, 2015.

For each of these variables, I summarize in Exhibit RJM-5 the range of values that Moody's considers for each credit rating.

Interest Coverage is calculated as the ratio of cash flow from operations before interest expense and changes in working capital (but after changes in other assets and liabilities such as regulatory capital and cash collateral) relative to interest expense. The ratio indicates the amount of cash flow available to pay interest, capital expenditures and other obligations per dollar of interest due, so a higher ratio is indicative of a higher credit rating. Moody's indicates that Ba-rated unregulated power companies tend to have *Interest Coverage* ratios of 2.8x to 4.2x and similarly rated regulated utilities tend to have ratios of 2.0x to 3.0x.[35]

Cash Flow / Debt is the ratio of cash flow from operations before changes in working capital relative to debt. A higher ratio indicates a stronger financial position and a higher credit rating. Moody's indicates that Ba-rated unregulated power companies tend to have *Cash Flow / Debt* ratios of 12 percent to 20 percent and similarly rated regulated utilities tend to have ratios of 5 percent to 13 percent.[36]

Retained Cash Flow / Debt is similar to *Cash Flow / Debt*, except the numerator subtracts dividend payments from *Cash Flow*. For DPL Inc., the projections do not include any dividends so there is no difference in the two measures of cash flows. Moody's indicates

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[35] Moody's Investors Service (2014) Rating Methodology for Unregulated Utilities and Unregulated Power Companies, at 36; Moody's Investors Service (2013) Rating Methodology for Regulated Electric and Gas Utilities, at 38. I focus on a Ba rating in order to maintain consistency with DPL Inc.'s current rating, which is based DP&L owning the coal-fired generating assets.

[36] Moody's Investors Service (2014) Rating Methodology for Unregulated Utilities and Unregulated Power Companies, at 36; Moody's Investors Service (2013) Rating Methodology for Regulated Electric and Gas Utilities, at 38.

that Ba-rated unregulated power companies tend to have *Retained Cash Flow / Debt* ratios of 8 percent to 15 percent and similarly rated regulated utilities tend to have ratios of 0 percent to 9 percent.[37]

Debt / Capital is calculated as the ratio of debt to capital (which includes short- and long-term debt, common equity, preferred stock and deferred taxes). The ratio indicates the degree of financial leverage. A higher ratio (greater leverage) is indicative of a lower credit rating. Moody's indicates that Ba-rated regulated utilities tend to have *Debt / Capital* ratios of 55 percent to 65 percent;[38] it does not include Debt / Capital among the factors with explicit weight in its evaluation of unregulated power companies.[39]

The table below summarizes the weights Moody's assigns to these metrics for DPL Inc. (which it rates as a regulated utility, using its Standard Grid) and unregulated power companies.

Metric	Regulated Utilities[40]	Unregulated Power Companies[41]
Interest Coverage	18.75%	25%
Cash Flow / Debt	37.50%	50%
Retained Cash Flow / Debt	25.00%	25%
Debt / Capital	18.75%	0%

[37] Moody's Investors Service (2014) Rating Methodology for Unregulated Utilities and Unregulated Power Companies, at 36; Moody's Investors Service (2013) Rating Methodology for Regulated Electric and Gas Utilities, at 38.
[38] Moody's Investors Service (2013) Rating Methodology for Regulated Electric and Gas Utilities, at 38.
[39] Moody's Investors Service (2014) Rating Methodology for Unregulated Utilities and Unregulated Power Companies, at 36.
[40] Moody's Investors Service (2013) Rating Methodology for Regulated Electric and Gas Utilities, at 6.
[41] Moody's Investors Service (2014) Rating Methodology for Unregulated Utilities and Unregulated Power Companies, at 8

To assign a credit rating, I assign a numerical score for each metric based on the Moody's criteria in Exhibit RJM-5. For example, *Interest Coverage* of 3.0x for a regulated utility translates to a Baa rating and a score of 9. *CF / Debt* and *RCF / Debt* metrics of 10.9 percent and 10.1 percent for a regulated utility result in ratings (scores) of Ba (12) for *CF / Debt* and Baa (9) for *RCF / Debt*. A *Debt / Capital* ratio of 74.3 percent corresponds to a B rating and a score of 15.[42] The composite rating score would be $0.1875 \times 9 + 0.375 \times 12 + 0.25 \times 9 + 0.1875 \times 15 = 11.25$, which translates to a rating of "Ba1."[43]

Q. Do the credit ratings assigned by the rating agencies depend on considerations other than the four factors that you have mentioned?

A. Yes. The credit rating agencies consider a broader array of factors, many of which require a subjective determination. I have focused on the above four quantitative factors in order to avoid subjective ratings. As a result, the assigned ratings should be interpreted as indicative rather than predictions of actual ratings. However, I note that the example above uses the actual metrics for DPL Inc. as of October 13, 2015. Fitch applies a three-notch reduction to DPL Inc.'s rating due to its structural subordination to DP&L-TD,[44] which would result in a "B1" rating, only one notch different from the assigned rating of

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[42] Moody's notes that DPL Inc. has "significant financial leverage" but does not provide a grid of leverage ranges by credit rating for unregulated power companies such as DPL Inc. under an MRO. For regulated utilities such as DP&L, Moody's does provide a grid of leverage ranges and a leverage ratio of 74 percent (DPL Inc. as of June 2015) falls in the B-rated category of that grid. Moody's Investors Service (2013) Rating Methodology for Regulated Electric and Gas Utilities, at 24. Moody's Investors Service, Credit Opinion: DPL Inc., October 13, 2015.

[43] In Moody's rating scale each letter grade is further divided into high, medium and low based on a numerical suffix (e.g., "Ba2" is below "Ba1" but above "Ba3").

[44] Structural subordination refers to the fact that the creditors to a holding company owning regulated subsidiaries typically have a claim on the consolidated group's cash flows and assets that is junior to the creditors of the subsidiaries. The holding company depends on dividends from its subsidiaries to service its debt, but the regulators of the subsidiary may prevent such dividends. To account for this additional risk, Moody's will lower the grid-based rating of a parent by one to three "notches" (e.g., a Ba2 rating is one notch lower than a Ba1 rating). Moody's Investors Service (2013) Rating Methodology for Regulated Electric and Gas Utilities, at 25-26.

"Ba3" that accounts for other factors. To preserve consistency, I apply the same three-notch reduction to the grid-based ratings based on the projected financial metrics for DPL Inc.

In Exhibit RJM-14, I perform a similar exercise for the parent companies of other utilities regulated by PUCO. The indicated credit ratings for AEP Company ("Baa1") and FirstEnergy ("Baa3") are exactly equal to the assigned credit ratings after accounting for the notching due to structural subordination. For Duke Energy Corporation, the indicated Baa2 rating is one notch below the assigned rating. These results indicate that the rating based on the grid is a reliable measure of Moody's assigned credit ratings.

Q. How will you apply your calculation of indicated credit ratings in this case?

A. An indicated credit rating, or a change in an indicative credit rating, provides a measure of financial condition or integrity, or a change in those characteristics, through a connection to default risk. The lower the rating, the higher is the default risk, and vice versa. In this case, DPL Inc. will have a heavy debt load at the time of separation which, all else equal, increases the probability of default.

D. INPUT DATA FOR FINANCIAL PROJECTIONS

Q. What information did you use to develop your financial projections for the coal-fired generating assets and DPL Inc.?

A. The financial projections are based on the dispatching model for period from 2017 to 2026 sponsored by Mr. Eugene Meehan of NERA, in addition to supplemental information provided to me by the Company for 2016 through 2025. The pro forma financial statements sponsored by Company Witness Craig Jackson also are based on this information.[45] Detailed information for 2026 was not available from the Company so for that year I used the information from Mr. Meehan's analysis along with additional modeling adjustments so that the resulting financials for 2026 were comparable to those in Mr. Jackson's exhibits.

Q. Have you done anything to assure yourself that the input data for the financial projections are sound?

A. Yes. I have performed the following procedures:

- I have reviewed the testimony of Mr. Jackson, as well as information provided to me by the Company and discussed the underlying assumptions with those responsible for their preparation.

- I tested the projections by comparing them to historical performance of the Company and its peers.

- I compared the projections for the regulated utility to those filed by DP&L in its pending rate case before PUCO.[46]

Q. What were the results of this analysis?

A. The projected O&M costs, debt and other information received from Mr. Jackson regarding the coal-fired generating facilities appear reasonable based on my comparisons. In addition, the projections of DP&L-TD's financial results are consistent with those filed

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[45] Direct Testimony of Craig L. Jackson, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM, at 6-8.
[46] Direct Testimony of Danial A. Santacruz, Public Utilities Commission of Ohio Case Nos. 15-1830-EL-AIR, 15-1831-EL-AAM, and 15-1832-EL-ATA.

in DP&L's distribution rate case. Thus, the projections assume that the PUCO will approve DP&L's distribution rates in that case.

Q. Can you describe the output that each plant is projected to generate over the forecast period?

A. [redacted]

Notes & Sources:
2011 - 2015 data from internal Company data.
2016 - 2026 data from Direct Testimony of Eugeen T. Meehan.

[redacted]

Notes & Sources:
Capacity factor calculated as Generation divided by (365*24)*DPL Portion.
DPL Portion from DPL Inc. 10-K for the fiscal year ended December 31, 2014, at p. 11.
2011 - 2015 data from internal Company data.
2016 - 2026 data from Direct Testimony of Eugeen T. Meehan.

Q. Please describe the prices for energy and capacity that you use in the financial projections for DP&L's coal-fired generating assets.

A. [redacted]

[47] Direct Testimony of Eugene T. Meehan, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM, at 12-13.

FIGURE 8

ENERGY PRICE, FUEL COST, AND DARK SPREAD FOR COAL-FIRED PLANTS

[redacted]

[redacted]

Notes & Sources:
2011 - 2015 uses historical Auction Clearing Price data from PJM.
2016 - 2025 calculated as the sum of coal-fired Plants capacity revenue divided by coal-fired Plants cleared capacity, divided by 365 days.
2016 - 2025 capacity revenue and cleared capacity from Direct Testimony of Eugeen T. Meehan.

Q. Please describe the projected fuel costs for the generating assets that you are analyzing.

A. [redacted]

[48] Moody's Investors Service, Credit Opinion: DPL Inc., October 13, 2015.

[redacted]

FIGURE 11

COAL PRICE PER TON

[redacted]

Q. Please describe the projected Operation and Maintenance ("O&M") costs that you are using?

A. I use the projected O&M costs provided to me in Company management reports. These reports project both direct and indirect O&M at the plant level. Indirect O&M is allocated using the Company's Cost Allocation Manual[49] (CAM) and AES's Cost Alignment and Allocation Manual (CAAM).[50] The CAM "directly supports the requirements established by the Public Utilities Commission of Ohio (PUCO) regarding the proper segregation of costs between business units" pursuant to Finding and Order in Case No. 99-141-EL-ORD (as revised).[51] The CAAM allocates costs of services provided by AES US Services, LLC to affiliates including DPL Inc. and DP&L.[52] Those costs are allocated without a mark-up or profit and with the intent of avoiding cross-subsidization, maximizing synergies and economies of scale, and minimizing time and expense needed to record and audit transactions.[53]

Figure 12 summarizes direct (including fuel handling costs), indirect, and total O&M for the five coal-fired plants during the projection period.

[49] The Dayton Power & Light Company, Cost Allocation Manual, January 1, 2015.
[50] AES US Services, LLC, Cost Alignment and Allocation Manual, revised January 1, 2015.
[51] The Dayton Power & Light Company (January 2015) Cost Allocation Manual, at 1.
[52] AES US Services, LLC (January 2015) Cost Alignment and Allocation Manual, at 1.
[53] AES US Services, LLC (January 2015) Cost Alignment and Allocation Manual, at 1.

FIGURE 12

OPERATION AND MAINTENANCE COSTS FOR COAL-FIRED PLANTS

[redacted]

FIGURE 13

DP&L OPERATION AND MAINTENANCE COSTS

[redacted]

Notes & Sources:
In millions.
2010-2015 from 10-Ks for 2012 - 2014, and 10Q for Q3 2015 (annualized).
2016-2025 data from Internal Company Sources.

Q. Please describe the projected capital expenditures that you have used in your analysis of the coal-fired generating assets and DPL Inc.

A. My forecasts incorporate the Company's projected capital expenditures, summarized in Figure 14 and Exhibit RJM-11. The capital expenditures consist of expenditures related to environmental requirements and maintenance needs. Examples of the environmental expenditures include emissions and pollution control projects (Flue Gas Desulfurization ("FGD"), Selective Catalytic Reduction ("SCR")), clean-up and remediation, by-product (ash disposal or landfill), and precipitator purchases. Over the ten-year period, capital expenditures total $[redacted].

As noted above, Fitch described DP&L's capex spending on the coal-fired generating assets as "the bare minimum required to maintain the reliability and the safety" of the assets.[54] As shown in Figure 14, average projected capex from 2015 through 2018 is $[redacted] million, as compared to $26 million annually during 2013 and 2014, the two years prior to Fitch's statement.

[54] Fitch Ratings, "DPL Inc. and Dayton Power & Light Company," October 7, 2014, at 2.

FIGURE 14

CAPITAL EXPENDITURES AT COAL-FIRED PLANTS

[redacted]

Notes & Sources:
2011 DP&L data from DPL Inc. 10-K for the fiscal year ended December 31, 2013, at 160.
2012-2014 DP&L data from DPL Inc. 10-K for the fiscal year ended December 31, 2014, at 131.
2015 DP&L capital expenditures estimated using capital expenditures for nine months ended September 30, 2015, from DPL Inc. 10-Q for the quarterly period ended September 30, 2015.
2016 - 2026 data from Internal Company Sources.

Q. Please describe the debt-related inputs to your financial projections.

A. As of the end of 2015, the combined entities had $2.0 billion in debt of various types, as shown in RJM-13. [redacted]

Q. Are there any capital structure or cost of capital inputs required for your financial projections?

A. Yes. As described further below, to calculate the RER, it is necessary to specify a particular capital structure and return on equity for DP&L's coal-fired generating assets subject to the RER. Company Witness Morin indicates that a 10.7 percent ROE is appropriate for the relevant coal-fired generating assets when operating under an ESP with an RER, based on a 50 percent debt-to-assets ratio.[55]

As discussed by Company Witness Jackson, the 5.29 percent cost of debt reflects the Company's cost of long-term anticipated debt, and was sponsored by Company Witness MacKay in Case No. 15-1830-EL-AIR et al.

Q. What is your assessment of the reasonableness of using Dr. Morin's 10.7 percent as a benchmark rate of return under an MRO?

A. Dr. Morin's determination of ROE for the coal-fired generating plants assumes the existence of an RER. All else equal, unregulated merchant generating assets are likely to have a higher required ROE than the coal-fired generation plants under an RER because they are riskier. This suggests that the 10.7 percent ROE would be too low, or conservative, for the coal-fired generating assets under an MRO.

E. PROJECTED FINANCIAL CONDITION OF THE COAL-FIRED GENERATING ASSESTS AND DPL INC. UNDER AN MRO

Q. Please describe the projected <u>near-term</u> financial condition of the coal-fired generating assets and DPL Inc. under an MRO.

A. [redacted]

[55] Direct Testimony of Dr. Roger A. Morin, Public Utilities Commission of Ohio, Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM, at 6.

[redacted]

[redacted]

[56] Moody's Investors Service "Annual Default Study: Corporate Default and Recovery Rates, 1920-2014," (2015), at 26.
[57] Credit Agreement among DPL Inc., U.S Bank National Association, PNC Bank, National Association, and Bank of America, N.A., July 31, 2015, at 95

[redacted]

Q. What do your projections indicate for the <u>longer-term</u> financial condition of the coal-fired generating assets and DPL Inc. under an MRO?

A. [redacted]

[redacted]

Q. Can you elaborate more on how DPL Inc. will pay down its debt under an MRO?

A. [redacted]

FIGURE 15

**DPL INC. LONG-TERM DEBT
UNDER AN MRO**

[redacted]

[58] Debt services is the sum of interest expense, retirement of long-term debt net of issuances and short-term debt.

[redacted]

From Exhibit RJM-11.

F. PROJECTED FINANCIAL CONDITION OF THE COAL-FIRED GENERATING ASSETS AND DPL INC. UNDER THE PROPOSED ESP (WITH RER)

Q. How is the RER calculated in your projections?

A. As explained by Company Witness Jackson, the RER is based on the annual variances between (a) the revenue requirement for DP&L's coal-fired generating assets (including a return on and of invested capital, income taxes, and fixed O&M), and (b) the revenues expected to be earned by those assets from the sale of capacity (net of capacity penalties), energy (net of fuel, emission allowance costs, and variable operating costs), and ancillary services to PJM markets.[59] Thus, the RER focuses on the high-level objective of providing a recovery of allowable costs, including the cost of debt and equity financing (based on Dr. Morin's 10.7 percent ROE).

More specifically, in Exhibit RJM-9 I identify the relevant operating costs (which include fuel costs, direct and indirect O&M, taxes, and depreciation). I add the cost of debt and equity capital and an allowance for income taxes to the operating costs to determine the revenue requirement. The variance between the projected revenue and the revenue requirement gives the amount of the RER for that year. When the projected revenues are less than the revenue requirement, as is the case for 2017-2020, the RER will result in a payment from customers to the Company. When projected revenues exceed the revenue requirement, as is the case for 2021-2026, the RER will result in a payment from the Company to customers.

I understand that in practice variances between actual revenues and expenses and the projections that were used to calculate the RER in the rate base at the start of the year will be subject to a true-up.

Q. Can you elaborate on how you incorporate the cost of capital in the RER?

A. The imputed dollar cost of debt is equal to the 5.29 percent cost of debt times the net asset base times a 50 percent debt / asset ratio. As discussed by Company Witness

[59] Direct Testimony of Craig L. Jackson, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM at 9-10.

Jackson, the 5.29 percent cost of debt reflects the Company's cost of anticipated long-term debt as of September 30, 2015, and was sponsored by Company Witness MacKay in Case No. 15-1830-EL-AIR et al. The imputed cost of equity is the 10.7 percent return on equity sponsored by Dr. Morin times the net asset base times a 50 percent equity / asset ratio.

According to Witness Jackson, "[t]he initial revenue requirement proposed here is based on the rate base of the assets, plus known and measurable changes in investments, of the Company's coal-fired generation fleet, multiplied by a rate of return on investment plus a projection of O&M costs and other costs traditionally recognized by the Commission in establishing a revenue requirement."[60] The RER for a particular year is calculated using the average asset base for that year.

Q. What is the amount of the RER that results from applying this calculation to the projections?

A. Exhibit RJM-9 summarizes the RER. The sum of the RER payments over the ten year period is -$455 million, indicating a net benefit to customers. Because the payments benefit the Company in the early years and the customers in the later years, I calculate the present value of the RER payments at discount rates ranging from 4 percent to 12 percent. The present value ranges from -$61 million (12 percent discount rate) to -$272 million (4 percent discount rate), again reflecting a net benefit to customers even after adjusting for timing and risk.

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[60] Direct Testimony of Craig L. Jackson, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM, at 9.

Q. Have you projected the <u>near-term</u> financial condition of the coal-fired generating assets and DPL Inc. under an ESP with the proposed RER?

A. Under the proposed ESP, the RER would take effect in 2017 and would run through the end of the projection period. These payments would produce an ROE for the coal-fired generating of 10.7 percent, equal to the level envisioned in the proposed RER, and would remain at that level through 2026. As a result, the free cash flows for DPL Inc.'s coal-fired generating assets for 2017 to 2019 would improve substantially. This additional cash flow would allow DPL Inc. to service its debt, including paying down debt at DP&L-TD by 2018 to meet the 50/50 capital structure required by the PUCO, without having to draw on short-term facilities and/or reduce capital expenditures at any of its subsidiaries.

I also note that the RER provides immediate long term stability and certainty regarding future cash flows, which will enable DPL Inc. to successfully manage short-term debt maturities and mitigate both the short- and long-term debt refinancing risk inherent in the MRO scenario.

[redacted]

[redacted]

Q. What do your projections indicate for the <u>longer-term</u> financial condition of DPL Inc. and the coal-fired generating assets under an ESP with the proposed RER?

A. DPL Inc.'s longer-term (2021 to 2026) financial condition would be similar under the ESP as under an MRO. [redacted] This is because under an MRO, DPL Inc. would enjoy higher earnings during these out years due to realizing the large upside of increased energy prices. Under the proposed ESP, DPL Inc. is projected to have somewhat higher earnings in the early years offset by lower earnings in the later years due to the need to pay rebates to customers. As a result, its financial condition as measured by debt ratings would be similar during these out years under the two rate regimes.

Q. Can you elaborate more on how DPL Inc. will pay down its debt under an ESP with an RER?

A. [redacted]

[redacted]

[61] The "Debt Service" bars shown in Figure 18 include all contractual debt payments that the Company projects will occur under an RER, including the prepayment of debt in 2018 to reduce the debt at DP&L-TD such that it will meet the required 50/50 capital structure target.

[redacted]

Notes & Sources:
From Exhibit RJM-12.

Q. Please summarize your analysis of the financial condition of the coal-fired generating assets and financial integrity of DPL Inc. in the presence of the RER.

A. With the RER in place from 2017 through 2026, the financial condition of the coal generating assets and by extension, the financial integrity of DPL Inc. would be maintained. The coal-fired generating plants would have an average ROE of 10.7 percent

[62] This free cash flow measure does not perfectly measure cash available to service debt because it ignores working capital and other adjustments for non-cash items in EBITDA.

throughout the period, including during the difficult 2017 to 2020 [redacted] In the near term, DPL Inc.'s improved cash flows would ensure that DPL Inc. could service its own debt while providing the equity capital to DP&L-TD that it needs to meet its 50 percent debt target by 2018. In the longer term, the improved cash flows will enable DPL Inc. to pay down and/or refinance its debt maturities in 2019, 2020 and 2021, and recapitalize so that its financial condition and integrity and DP&L-TD would no longer be negatively impacted by the underperformance of its coal-fired generation fleet.

IV. "MORE FAVORABLE IN THE AGGREGATE"

A. AN OVERVIEW OF THE STATUTORY TEST

Q. Does DP&L's ESP have to meet certain requirements for approval by the Commission?

A. Yes. For the Commission to approve a utility company's ESP, the ESP must meet certain criteria that are specified in Section 4928.143 of the Ohio Revised Code. One of these criteria, specified in Section 4928.143 (C)(1), is:

> that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code.

My testimony provides an assessment of whether the Company's ESP with a proposed RER meets this criterion.

Q. Do prior Commission decisions provide guidance on how to interpret this criterion?

A. Yes. In prior rulings in which the Commission has decided that ESPs met this "more favorable in the aggregate" test, the Commission has taken a broad view of the expected impacts of the different rate regimes to consider when performing this test, including (a) quantifiable differences in the prices to be charged to customers for electric generation service under each rate regime (Aggregate Price Test), (b) other quantifiable differences in customer charges (or, potentially, metrics of customer service), and (c) non-quantifiable differences.[63] This last category potentially includes a wide range of impacts, including expected short- and long-run effects on price, service quality, reliability, and the range of product offerings. These differences also support broader effects on Ohio's economy through the impact of electric rates and services to business and industry within the state.

Reflecting this broad perspective, my assessment of the "more favorable in the aggregate" requirement considers multiple quantifiable and non-quantifiable characteristics of the Company's proposed ESP versus those of a hypothetical alternative MRO.

Q. What elements have you considered in your comparison of the two alternative plans?

A. First, I perform an Aggregate Price Test, which compares rates and charges to customers that choose DP&L's Standard Service Offer (SSO) under the ESP as compared to the

[63] Public Utilities Commission of Ohio, Opinion and Order, Case No. 11-346-EL-SSO, August 8, 2012; Public Utilities Commission of Ohio, Opinion and Order, Case No. 12-1230-EL-SSO, July 18, 2012; Public Utilities Commission of Ohio, Opinion and Order, Case No. 12-426-EL-SSO, September 4, 2013.

rates and charges that they would pay if they chose the SSO under an MRO. This test reflects both bypassable and non-bypassable charges. The rate structure of this hypothetical MRO is assumed to be similar to DP&L's ESP in every material respect, except that the ESP would include the proposed RER and the MRO would not. Therefore, the Aggregate Price Test is effectively an analysis of the RER.

Second, I consider other costs or benefits that are quantifiable but are separate from the SSO. Examples include the economic impact if the coal-fired generating assets had to be retired, and the associated cost of transmission upgrades and infrastructure necessary to ensure the reliability of the electricity grid. The likelihood of such closures would increase in the absence of an RER.

Third, I consider other differences between the ESP and an MRO which are meaningful but whose effects are difficult or impossible to quantify accurately. These include a range of effects, such as the impact on the reliability of the electricity service and the volatility of electricity rates as illustrated by the price paid under each rate design by customers during extreme events such as the Polar Vortex of 2014.

B. AGGREGATE PRICE TEST FOR DP&L'S ESP

Q. What is the Aggregate Price Test?

A. The Aggregate Price Test is a comparison of the projected prices and charges to customers under DP&L's ESP as compared to an MRO. The Aggregate Price Test reflects a comparison of both bypassable and non-bypassable charges. Bypassable charges are charges that are paid only by customers that choose DP&L's Standard Service Offer (SSO). Thus, customers who choose to take generation service from a

Competitive Retail Electric Service (CRES) provider "bypass" these charges. Non-bypassable charges are charges paid by all customers that receive distribution service from DP&L.

Q. Please describe the comparison of bypassable charges.

A. Under both the ESP and MRO, bypassable rates beginning in 2017 will reflect the Competitive Bidding Plan (CBP) rate, which reflects the projected results of competitive bidding for the opportunity to supply DP&L's retail customers. Consequently, the bypassable portion of SSO rates will be the same under both the MRO and ESP.

Q. Do you also consider non-bypassable customer charges?

A. Yes. The Aggregate Price Test explicitly considers non-bypassable charges such as an RER. Exhibit RJM-10 summarizes the proposed RER from 2017 through 2026. Over that period, the RER totals nearly -$455 million, which indicates that on balance customers would pay lower rates than they would absent the RER. The time pattern of the RER is such that payments flow from customers to the Company in the earlier years and in the opposite direction – from the Company to customers – in the later years. During the first four years, when the Company is expected to face financial challenges, including in particular the need to reduce its debt burden, the Company receives an average of about $80 million per year. During the last six years, when the Company has improved its financial condition by delevering, the Company pays customers an average of $130 million.

Because the benefits to customers are in the future, I also consider a present value calculation to account for the timing and uncertainty of those payments. Since the

Aggregate Price Test is from the perspective of the customers, I consider discount rates ranging from 4 percent to 12 percent. This range is based on (a) a calculated after-tax weighted average cost of capital for the coal-fired generating assets under an RER of approximately 7 percent (based on the relevant cost of debt and Dr. Morin's testimony), and (b) recognition that the risk of the future stream of cash flows from the RER has a risk level reasonably approximated by the risk of the profits of the coal-fired generating assets.

Based on this range, the present value of the ten-year stream of RER payments ranges from $272 million with the 4 percent discount rate to $61 million with the 12 percent discount rate. In all cases, the Aggregate Price Test indicates that the ESP with the proposed RER is more favorable in the aggregate than the MRO.

Q. Did you quantify any of the other non-bypassable customer charges in the Aggregate Price Test?

A. No. DP&L has proposed several other non-bypassable charges such as the Distribution Investment Rider, Transmission Cost Recovery Rider – Non-bypassable (TCRR-N), the Reconciliation Rider (RR), and has proposed a placeholder for the Clean Energy Rider – Non-bypassable that I do not explicitly address in my analysis. These charges largely reflect pass-through of various costs to customers and would be present in both the proposed ESP and hypothetical MRO. Consequently, they would have no impact on the Aggregate Price Test.

Q. What do you conclude about the impact of DP&L's ESP on customer charges compared to the MRO?

A. Over the 2017 to 2026 period, the ESP with the proposed RER is expected to produce lower charges to SSO customers than an MRO. As summarized below, this overall cost savings to consumers arises from a combination of higher charges for 2017 through 2020 followed by lower charges from 2021 through 2026.

Q. Are there other quantifiable or partially quantifiable differences between the ESP and the MRO that are not captured in the Aggregate Price Test, but that are relevant to determining if the ESP is "more favorable in the aggregate"?

A. Yes. To the extent that an MRO would result in the retirement of the coal-fired generating plants, there are two primary benefits to an ESP. I provide a summary here, as other witnesses discuss those benefits in detail.

First, the ESP would avoid adverse economic impacts such as price increases and job losses that would occur if the coal-fired generating plants were to be retired. Company Witness Harrison of NERA estimates that such closures would increase retail energy prices by about 10 percent for residential customers, 13 percent for commercial customers and 11 percent for industrial customers. The direct and indirect effects of those closures would reduce employment in Ohio by about 19,000, spread across a number of industries, and cause a population reduction of over 26,000 residents.[64] That level of job losses would erase approximately 40 percent of the job growth projected by the Ohio

[64] The direct employment of the six generating facilities under consideration is about one thousand. Direct Testimony of David Harrison, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0396-EL-ATA, 16-0397-EL-AAM, at 7-8.

Bureau of Labor Market Information. These effects, which are net of the offsetting benefits associated with the development of new generation facilities, translate into nearly $3.2 billion annual reduction of gross state product, or about $25 billion in present value over the ten-year period. The local effects on the DP&L service area are likely to be even more severe than these statewide impacts.[65]

Second, the ESP would avoid the need for upgrades to the transmission infrastructure that would be necessary to balance load and provide a reliable electricity grid if certain coal-fired generating plants were to be retired. Dr. Carlos Grande-Moran of Siemens PTI has testified that the transmission upgrades such as additional transmission lines and substations that would be necessary would cost about $112 million. In addition to the quantified cost of these investments, Dr. Grande-Moran explains that the system would be less robust to stress events such as the Polar Vortex.

In sum, adoption of the proposed RER makes the retirement of coal plants less likely, resulting in both short- and long-run benefits to the state's customers and economy.

Q. Is it more likely that the coal-fired generating assets would be retired under an MRO?

A. Yes. As I have discussed above, under an MRO, the coal-fired generating assets and DPL Inc. both would experience sub-par earnings and a weakened financial position in the near-term that would delay their ability to reduce their debt and risk of default. During this period, DPL Inc. would be significantly more vulnerable to an economic shock that

[65] For example, Mr. Harrison shows that the retail price increases in counties where the relevant generating facilities are located are far larger than the price increases in other counties of Ohio. Direct Testimony of David Harrison, Public Utilities Commission of Ohio Case Nos. 16-0395-EL-SSO, 16-0397-EL-AAM, 16-0396-EL-ATA, at 21.

would make one or more of the generating plants uneconomic and, therefore, subject to retirement. One such shock would be that the expected increases in energy prices do not materialize, or that there were actual declines in energy prices. In that case, under an MRO, the plants would be at high risk of becoming uneconomic and being retired.

C. OTHER, NON-QUANTIFIABLE EFFECTS OF THE PROPOSED ESP AND MRO

Q. Does DP&L's ESP with the proposed RER provide other non-quantifiable benefits relative to an MRO?

A. Yes. In addition to the quantifiable or partially quantifiable benefits discussed above, DP&L's ESP provides additional benefits that would not be experienced under an MRO. In particular:

1. As noted above, the coal-fired generating assets would experience significant financial stress under an MRO during the 2017 to 2020 period. As a result, the Company may need to further increase its issuance of debt or otherwise keep operations running, or reduce capital expenditures or operating costs necessary to provide reliable and high quality electric service. The acute financial distress will be reduced or eliminated under an ESP with an RER, thereby reducing or eliminating the risk that DPL Inc. will be unable to service its debt or make necessary capital expenditures and other investments. This risk reduction represents a non-quantifiable benefit of the ESP to DP&L-TD's customers.
2. The ESP would provide for a more robust electricity grid that would be less susceptible to blackouts. Events such events as the Polar Vortex in 2014

placed tremendous stress on the electricity grid in the service area. Although that event did not result in blackouts, it did result in enormous spikes in electricity prices. To the extent that denial of the proposed ESP would result in the retirement of certain generating plants, the capacity in the system would be lower, at least in near term, and similar events in the future would likely result in even larger price spikes and may also result in blackouts. Witness Miller provides testimony that explains this risk in greater detail.

3. As discussed in the testimony of Company Witness Grande-Moran, the generating assets play a key role in maintaining system frequency. The closure of those plants would thus create risks that the transmission system would be unable to maintain an appropriate frequency, which could also lead to blackouts.

V. CONCLUSION

Q. Does approval of the proposed ESP with an RER reduce the chances that deterioration in the financial condition of the coal-fired generating assets and DPL Inc. would adversely affect consumers in the service area?

A. [redacted]

[redacted]

Q. Do you conclude that DP&L's ESP is "more favorable in the aggregate" than an MRO?

A. Yes. The facts and my analysis support that conclusion. Over the period from 2017 to 2026, DP&L's ESP would result in lower rates and charges to DP&L customers taking SSO service than an MRO. In addition, an ESP would significantly decrease the likelihood that the Company will be unable to make the investments necessary to ensure safe and reliable service. Further, the ESP provides non-quantifiable benefits that exceed those under an MRO. Consequently, I conclude that DP&L's ESP is "more favorable in the aggregate" than an MRO.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT RJM-1

DPL INC. PRO FORMA FINANCIAL RATIOS
WITHOUT RER
2017 – 2026

Ratio	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RER	[redacted]									
Debt										
Debt/EBITDA										
Debt/Capital										
EBITDA/Interest										
Interest Coverage										
Cash Flow/Debt										
Retained Cash Flow/Debt										
Implied Moody's Rating - Regulat										
Interest Coverage										
Cash Flow/Debt										
Retained Cash Flow/Debt										
Debt/Capital										
Weighted Average										
Indicated Rating										
Implied Moody's Rating - Unregu										
Interest Coverage										
Cash Flow/Debt										
Retained Cash Flow/Debt										
Weighted Average										
Indicated Rating										

Notes & Sources:
In thousands.
Interest Coverage = (CFO Pre-WC + Gross Interest Expense) / Interest Expense.
Cash Flow/Debt = CFO Pre-WC / DPL Inc. Consolidated Total Debt.
Retained Cash Flow/Debt = (CFO Pre-WC - Dividends) / DPL Inc. Consolidated Total Debt.
Debt/Capital = DPL Inc. Consolidated Total Debt / Total Capitalization.
Implied Regulated Ratings calculated using Moody's report 'Regulated Electric and Gas Utilities,' December 2013. See Exhibit RJM-5. Weighted Average based on weights of 18.75% (Interest Coverage), 37.50% (CF/Debt), 25.00% (RCF/Debt), and 18.75% (Debt/Capital).
Implied Unregulated Ratings calculated using Moody's Rating Methodology, Unregulated Utilities and Unregulated Power Companies, October 31, 2014. See Exhibit RJM-5. Weighted Average based on weights of 25% (Interest Coverage), 50% (CF/Debt), and 25% (RCF/Debt).
From Exhibit RJM-2.

EXHIBIT RJM-2

DPL INC.
DATA FOR FINANCIAL RATIO CALCULATIONS
WITHOUT RER
2017 – 2026

	Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Statements of Income	[redacted]									
[1]	Total Revenue										
[2]	Operating EBITDA										
[3]	Operating Income										
[4]	Gross Interest Expense										
[5]	Depreciation and Amortization										
[6]	Net Income										
	Statement of Cash Flows										
[7]	Net Cash Provided by Operating Activities										
[8]	Change in Working Capital										
[9]	CFO Pre-WC										
[10]	Capital Expenditures										
	Balance Sheet										
	DPL Inc. Consolidated Debt										
[11]	Long-Term Debt										
[12]	Current Portion of Long Term Debt										
[13]	Short-Term Debt										
[14]	Total DPL Inc. Consolidated Debt										
	DPL Inc. HoldCo Debt										
[15]	Long-Term Debt										
[16]	Current Portion of Long Term Debt										
[17]	Short-Term Debt										
[18]	Total DPL Inc. Hold Co Debt										
	DP&L-TD Debt										
[19]	Long-Term Debt										
[20]	Current Portion of Long Term Debt										
[21]	Short-Term Debt										
[22]	Total DP&L-TD Debt										
[23]	Unrestricted Cash										
[24]	Net DPL Inc Consolidated Debt										
[25]	Common Shareholder's Equity										
[26]	Average Common Shareholder's Equity										
[27]	Deferred Taxes										
[28]	Total Capitalization										

Notes & Sources:
In thousands.
[8] = change in Accounts Receivable plus change in Inventory less change in Accounts Payable.
[9] = [7] - [8].
[24] = [14] - [23].
From Exhibit RJM-6.

EXHIBIT RJM-3

DPL INC. PRO FORMA FINANCIAL RATIOS
WITH RER
2017 – 2026

Ratio	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RER	$130,825	$105,376	$69,121	$13,886	($53,545)	($93,588)	($141,851)	($207,053)	($120,073)	($157,923)
Debt	[redacted]									
Debt/EBITDA										
Debt/Capital										
EBITDA/Interest										
Interest Coverage										
Cash Flow/Debt										
Retained Cash Flow/Debt										
Implied Moody's Rating - Regulat										
Interest Coverage										
Cash Flow/Debt										
Retained Cash Flow/Debt										
Debt/Capital										
Weighted Average										
Indicated Rating										

<u>Notes & Sources</u>:
In thousands.
Interest Coverage = (CFO Pre-WC + Gross Interest Expense) / Interest Expense.
Cash Flow/Debt = CFO Pre-WC / DPL Inc. Consolidated Total Debt.
Retained Cash Flow/Debt = (CFO Pre-WC - Dividends) / DPL Inc. Consolidated Total Debt.
Debt/Capital = DPL Inc. Consolidated Total Debt / Total Capitalization.
Implied Ratings calculated using Moody's report 'Regulated Electric and Gas Utilities,' December 2013. See Exhibit RJM-5. Weighted Average based on weights of 18.75% (Interest Coverage), 37.50% (CF/Debt), 25.00% (RCF/Debt), and 18.75% (Debt/Capital).
From Exhibit RJM-4.

EXHIBIT RJM-4

DPL INC.
DATA FOR FINANCIAL RATIO CALCULATIONS
WITH RER
2017 – 2026

	Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Statements of Income	[redacted]									
[1]	Total Revenue										
[2]	Operating EBITDA										
[3]	Operating Income										
[4]	Gross Interest Expense										
[5]	Depreciation and Amortization										
[6]	Net Income										
	Statement of Cash Flows										
[7]	Net Cash Provided by Operating Activities										
[8]	Change in Working Capital										
[9]	CFO Pre-WC										
[10]	Capital Expenditures										
	Balance Sheet										
	DPL Inc. Consolidated Debt										
[11]	Long-Term Debt										
[12]	Current Portion of Long Term Debt										
[13]	Short-Term Debt										
[14]	Total DPL Inc. Consolidated Debt										
	DPL Inc. HoldCo Debt										
[15]	Long-Term Debt										
[16]	Current Portion of Long Term Debt										
[17]	Short-Term Debt										
[18]	Total DPL Inc. Hold Co Debt										
	DP&L-TD Debt										
[19]	Long-Term Debt										
[20]	Current Portion of Long Term Debt										
[21]	Short-Term Debt										
[22]	Total DP&L-TD Debt										
[23]	Unrestricted Cash										
[24]	Net DPL Inc Consolidated Debt										
[25]	Common Shareholder's Equity										
[26]	Average Common Shareholder's Equity										
[27]	Deferred Taxes										
[28]	Total Capitalization										

Notes & Sources:

In thousands.

[8] = change in Accounts Receivable plus change in Inventory less change in Accounts Payable.

[9] = [7] - [8].

[24] = [14] - [23].

From Exhibit RJM-7.

EXHIBIT RJM-5

MOODY'S RATINGS TABLES

Regulated Electric and Gas Utilities

	Interest Coverage		CF/Debt		RCF/Debt		Debt/Capital	
Rating	Min	Max	Min	Max	Min	Max	Min	Max
Aaa	8.0x	>8.0x	40.0%	>40.0%	35.0%	>35.0%	<25.0%	25.0%
Aa	6.0x	8.0x	30.0%	40.0%	25.0%	35.0%	25.0%	35.0%
A	4.5x	6.0x	22.0%	30.0%	17.0%	25.0%	35.0%	45.0%
Baa	3.0x	4.5x	13.0%	22.0%	9.0%	17.0%	45.0%	55.0%
Ba	2.0x	3.0x	5.0%	13.0%	0.0%	9.0%	55.0%	65.0%
B	1.0x	2.0x	1.0%	5.0%	-5.0%	0.0%	65.0%	75.0%
Caa	<1.0x	1.0x	<0.0%	0.0%	<-5.0%	-5.0%	75.0%	>75.0%

Unregulated Utilities and Unregulated Power Companies

	Interest Coverage		CF/Debt		RCF/Debt	
Rating	Min	Max	Min	Max	Min	Max
Aaa	18.0x	>18.0x	90.0%	>90.0%	60.0%	>60.0%
Aa	13.0x	18.0x	60.0%	90.0%	45.0%	60.0%
A	8.0x	13.0x	35.0%	60.0%	25.0%	45.0%
Baa	4.2x	8.0x	20.0%	35.0%	15.0%	25.0%
Ba	2.8x	4.2x	12.0%	20.0%	8.0%	15.0%
B	1.1x	2.8x	5.0%	12.0%	3.0%	8.0%
Caa	<1.1x	1.1x	<5.0%	5.0%	<3.0%	3.0%

Notes & Sources:
Interest Coverage = (CFO Pre-WC + Gross Interest Expense) / Interest Expense.
Cash Flow/Debt = CFO Pre-WC / DPL Inc. Consolidated Total Debt.
Retained Cash Flow/Debt = (CFO Pre-WC - Dividends) / DPL Inc. Consolidated Total Debt.
Debt/Capital = DPL Inc. Consolidated Total Debt / Total Capitalization.
From Moody's report "Regulated Electric and Gas Utilities," December 2013, and Moody's Rating Methodology, Unregulated Utilities and Unregulated Power Companies, October 31, 2014.

EXHIBIT RJM-6A

DPL INC.
INCOME STATEMENT
WITHOUT RER
2017 – 2026

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Retail Revenues	[redacted]									
Generation Sales										
RER										
Energy and Ancillary Sales										
Capacity Sales										
Capacity Penalties (net of bonuses)										
Other Generation Revenues										
Total Generation Revenues										
Other Revenues										
Total Revenues										
Cost of Revenues										
Fuel Related Costs										
Electricity Purchased For Resale										
Total Cost of Revenues										
Gross Margin										
O&M										
Taxes Other than Income Taxes										
Total Operating Expenses										
Operating EBITDA										
Depreciation and Amortization										
Operating Income										
Interest Expense										
Interest (Income) - Other										
Other Expense / (Income)										
Income Before Taxes										
Current Income Tax Expense										
Deferred Income Tax Expense										
Total Income Taxes										
Net Income										
Preferred Stock Dividend (Accrued)										
Net Income Attributable to AES										
Dividend to AES										
Retained Earnings										

<u>Notes & Sources</u>:
In thousands.
Surplus cash flows are used to prepay long-term debt. A cash flow deficit is covered by drawing on revolving line of credit.
From internal Company projections.

EXHIBIT RJM-6B

DPL INC.
BALANCE SHEET
WITHOUT RER
2017 – 2026

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ASSETS										
Current Assets	[redacted]									
Cash Held at DPL Inc										
Cash Held at Subsidiary Level										
Accounts Receivable										
Inventory - Fuel and Raw Materials										
Inventory - Spare Parts and Supplies										
General Taxes Applicable to Future Years										
Regulatory Assets - Fixed										
Other Current Assets - Fixed										
Total Current Assets										
Property, Plant & Equipment										
Gross Plant in Service										
Construction Work in Progress										
Accumulated Depreciation										
Net PP&E										
Other Non-Current Assets										
TOTAL ASSETS										
LIABILITIES AND SHAREHOLDERS EQUITY										
Current Liabilities										
Accounts Payable										
Current Portion of Long-Term Debt										
Short-Term Debt										
Current Income Taxes Payable										
Other Current Liabilities										
Total Current Liabilities										
Non-Current Liabilities										
Long-Term Debt										
Deferred Income Taxes - Non-Current										
Other Non-Current Liabilities										
Total Non-Current Liabilities										
Shareholders' Equity										
Additional Paid-in Capital										
Cumulative Parent Equity Infusion										
Retained Earnings (Accumulated Deficit)										
Total Common Shareholders' Equity										
Non-Controlling Interests (Preferred Stock)										
Total Stockholders' Equity (Deficit)										
TOTAL CAPITALIZATION AND LIABILITIES										

Notes & Sources:
In thousands.
Surplus cash flows are used to prepay long-term debt. A cash flow deficit is covered by drawing on revolving line of credit.
From internal Company projections.

EXHIBIT RJM-6C

DPL INC.
CASH FLOWS
WITHOUT RER
2017 – 2026

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Operating Activities	[redacted]									
Net Income (Loss)										
Adjustments										
Depreciation and Amortization										
Provision for Deferred Taxes										
(Decrease) Increase in Accounts Payable and Pension Contributions										
Decrease (Increase) in Accounts Receivable										
Inventory										
Other Operating Cash Flows										
Net Cash Provided by Operating Activities										
Investing Activities										
CapEx										
Other Investing Activities										
Net Cash Used in Investing Activities										
Financing Activities										
Net borrowings Under Revolving Credit Facilities										
Issuance of Debt										
Repayments of Debt										
Debt Issuance Fees										
Preferred Stock Dividends Paid										
Dividends Paid to AES Corp										
Net Cash Provided by / (Used for) Financing Activities										
(Decrease) Increase in Cash and Cash Equivalents										

<u>Notes & Sources</u>:
In thousands.
Surplus cash flows are used to prepay long-term debt. A cash flow deficit is covered by drawing on revolving line of credit.
From internal Company projections.

EXHIBIT RJM-7A

DPL INC.
INCOME STATEMENT
WITH RER
2017 – 2026

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Retail Revenues	[redacted]									
Generation Sales										
RER										
Energy and Ancillary Sales										
Capacity Sales										
Capacity Penalties (net of bonuses)										
Other Generation Revenues										
Total Generation Revenues										
Other Revenues										
Total Revenues										
Cost of Revenues										
Fuel Related Costs										
Electricity Purchased For Resale										
Total Cost of Revenues										
Gross Margin										
O&M										
Taxes Other than Income Taxes										
Total Operating Expenses										
Operating EBITDA										
Depreciation and Amortization										
Operating Income										
Interest Expense										
Interest (Income) - Other										
Other Expense / (Income)										
Income Before Taxes										
Current Income Tax Expense										
Deferred Income Tax Expense										
Total Income Taxes										
Net Income										
Preferred Stock Dividend (Accrued)										
Net Income Attributable to AES										
Dividend to AES										
Retained Earnings										

<u>Notes & Sources</u>:
In thousands.
Surplus cash flows are used to prepay long-term debt. A cash flow deficit is covered by drawing on revolving line of credit.
From internal Company projections.

EXHIBIT RJM-7B

DPL INC.
BALANCE SHEET
WITH RER
2017 – 2026

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ASSETS	[redacted]									
Current Assets										
Cash Held at DPL Inc										
Cash Held at Subsidiary Level										
Accounts Receivable										
Inventory - Fuel and Raw Materials										
Inventory - Spare Parts and Supplies										
General Taxes Applicable to Future Years										
Regulatory Assets - Fixed										
Other Current Assets - Fixed										
Total Current Assets										
Property, Plant & Equipment										
Gross Plant in Service										
Construction Work in Progress										
Accumulated Depreciation										
Net PP&E										
Other Non-Current Assets										
TOTAL ASSETS										
LIABILITIES AND SHAREHOLDERS EQUITY										
Current Liabilities										
Accounts Payable										
Current Portion of Long-Term Debt										
Short-Term Debt										
Current Income Taxes Payable										
Other Current Liabilities										
Total Current Liabilities										
Non-Current Liabilities										
Long-Term Debt										
Deferred Income Taxes - Non-Current										
Other Non-Current Liabilities										
Total Non-Current Liabilities										
Shareholders' Equity										
Additional Paid-in Capital										
Cumulative Parent Equity Infusion										
Retained Earnings (Accumulated Deficit)										
Total Common Shareholders' Equity										
Non-Controlling Interests (Preferred Stock)										
Total Stockholders' Equity (Deficit)										
TOTAL CAPITALIZATION AND LIABILITIES										

<u>Notes & Sources</u>:
In thousands.
Surplus cash flows are used to prepay long-term debt. A cash flow deficit is covered by drawing on revolving line of credit.
From internal Company projections.

EXHIBIT RJM-7C

DPL INC.
CASH FLOWS
WITH RER
2017 – 2026

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Operating Activities	[redacted]									
Net Income (Loss)										
Adjustments										
Depreciation and Amortization										
Provision for Deferred Taxes										
(Decrease) Increase in Accounts Payable and Pension Contributions										
Decrease (Increase) in Accounts Receivable										
Inventory										
Other Operating Cash Flows										
Net Cash Provided by Operating Activities										
Investing Activities										
CapEx										
Other Investing Activities										
Net Cash Used in Investing Activities										
Financing Activities										
Net borrowings Under Revolving Credit Facilities										
Issuance of Debt										
Repayments of Debt										
Debt Issuance Fees										
Preferred Stock Dividends Paid										
Dividends Paid to AES Corp										
Net Cash Provided by / (Used for) Financing Activities										
(Decrease) Increase in Cash and Cash Equivalents										

Notes & Sources:
In thousands.
Surplus cash flows are used to prepay long-term debt. A cash flow deficit is covered by drawing on revolving line of credit.
From internal Company projections.

EXHIBIT RJM-8

COAL-FIRED GENERATION ASSETS
INCOME FROM OPERATIONS
2017 – 2026

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy Sales	[redacted]									
Capacity Sales										
Capacity Penalties (net of bonuses)										
Other Generation Revenues										
Total Generation Revenues										
Fuel Related Costs										
OVEC Energy and Demand Payments										
Total Cost of Revenues										
Gross Margin										
Direct O&M Expense										
Indirect O&M Expense										
General Taxes										
Total Operating Expenses										
Operating EBITDA										
Depreciation and Amortization										
Operating Income (without RER)										
With RER										
RER	$130,825	$105,376	$69,121	$13,886	($53,545)	($93,588)	($141,851)	($207,053)	($120,073)	($157,923)
Total Generation Revenues	[redacted]									
Gross Margin										
Operating Income										

Notes & Sources:
In thousands.
From internal Company projections.

EXHIBIT RJM-9

COAL-FIRED GENERATION ASSETS
RER CALCULATION
2017 – 2026

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
[1]	Net Book Value	[redacted]									
[2]	Pension										
[3]	ADIT Pension										
[4]	Working Capital - Fuel and Raw Materials										
[5]	Working Capital - Spare Parts and Supplies										
[6]	Less Deferred Tax										
[7]	Adjusted Asset Base										
[8]	Average Adjusted Asset Base										
	Operating Costs										
[9]	Fuel Related Costs, Including Emission Cost										
[10]	Direct O&M Expense										
[11]	Indirect O&M Expense										
[12]	General Taxes										
[13]	Depreciation										
[14]	Total Operating Costs										
[15]	Imputed Debt Expense										
[16]	Income Taxes										
[17]	Cost of Equity										
[18]	Required Operating Revenue										
[19]	Energy, Ancillary and Other Revenue										
[20]	Capacity Revenue										
[21]	Less Capacity Penalties (net of bonuses)										
[22]	Projected Operating Revenue										
[23]	RER	$130,825	$105,376	$69,121	$13,886	($53,545)	($93,588)	($141,851)	($207,053)	($120,073)	($157,923)

Notes & Sources:
In thousands.
Baseload plants are Stuart, Conesville, Killen, Miami Fort, and Zimmer.
From internal Company projections.
[8] = Average of [7] from current year and [7] from previous year. For 2017, it equals [7] of 2017.
[15] = [8] * 50% Debt/Assets * 5.29% Interest Rate.
[16] = [17] / (1 - 35.47%) * 35.47%. The 35.47% tax rate is calculated using the gross revenue conversion factor of 1.54977 from 2015 Distribution Base Rate Case, Book II- Schedules, Volume 1 of 4, at Schedule A-2. It equals (1.54977 - 1)/ 1.54977.
[17] = [8] * (1 - 50%) Debt/Assets * 10.70% Targeted ROE.
[18] = [14] + [15] + [16] + [17].
[19] = Energy Sales + Ancillary Services + Other Generation Revenues.
[21] Allocated to Coal-Fired Generation Assets based on share of total Company cleared capacity.
[23] = [18] - [22].

EXHIBIT RJM-10

COAL-FIRED GENERATION ASSETS
ANALYSIS OF RER
2017 – 2026

			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
[1]	RER		$130,825	$105,376	$69,121	$13,886	($53,545)	($93,588)	($141,851)	($207,053)	($120,073)	($157,923)
	Summary of RER											
[2]	Total	($454,824)										
[3]	Present Value at 4%	($271,571)										
[4]	Present Value at 6%	($203,249)										
[5]	Present Value at 8%	($146,711)										
[6]	Present Value at 10%	($99,832)										
[7]	Present Value at 12%	($60,898)										
[8]	Operating Income (Without RER)	[redacted]										
[9]	RER											
[10]	Less Imputed Interest											
[11]	Taxable Income											
[12]	Less Tax											
[13]	Net Income with RER											
[14]	Taxable Income (Without RER)											
[15]	Less Tax											
[16]	Net Income without RER											
[17]	Average Equity											
[18]	ROE with RER	[redacted]										
[19]	ROE without RER											

Notes & Sources:
[1] From Exhibit RJM-9.
[8] From Exhibit RJM-8.
[9] From Exhibit RJM-9.
[10] From Exhibit RJM-9.
[12] = 35.47% * [11]. 35.47% tax rate from Exhibit RJM-9.
[13] = [11] + [12].
[14] = [8] + [10].
[15] = 35.47% * [14].
[16] = [14] + [15].
[17] From Exhibit RJM-9. Assumes 50% Debt/Assets.
[18] = [13] / [17].
[19] = [16] / [17].

EXHIBIT RJM-11

ANALYSIS OF DEBT SERVICE ABILITY WITHOUT RER 2017 – 2026

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	EBITDA	[redacted]									
[1]	Coal-Fired Generation Assets										
[2]	DP&L-TD										
[3]	Other										
[4]	DPL Inc Consolidated Total										
	CapEx										
[5]	Coal-Fired Generation Assets										
[6]	DP&L-TD										
[7]	Other										
[8]	DPL Inc Consolidated Total										
	Estimated Funds Available for Debt Service										
[9]	Coal-Fired Generation Assets										
[10]	DP&L-TD										
[11]	Other										
[12]	DPL Inc Consolidated Total										
	Debt Service										
[13]	Debt Issued by DPL Inc.										
[14]	Debt Issued by DP&L-TD										
[15]	DPL Inc. Consolidated										
[16]	Deficit (Surplus) of DP&L-TD Debt Service										
[17]	DPL Inc Debt Service After Adjusting for DP&L-TD Surplus										
[18]	DPL Inc. Debt Service After Contribution from Other										
[19]	Funds Available for Debt Service from Coal-Fired Generation Assets										
[20]	Shortfall (Surplus)										
	Revolver Available as of Beginning of Year										
[21]	DPL Inc. HoldCo										
[22]	DP&L-TD										
[23]	DPL Inc. Consolidated										

EXHIBIT RJM-11

ANALYSIS OF DEBT SERVICE ABILITY
WITHOUT RER
2017 – 2026

<u>Notes & Sources</u>:

In thousands.

[1] = Operating EBITDA from Exhibit RJM-8.
[2] From internal Company projections.
[3] = [4] - [1] - [2].
[4] = Operating EBITDA from Exhibit RJM-6.
[5]-[6] From internal Company projections.
[7] = [8] - [5] - [6].
[8] From Exhibit RJM-6.
[9] = [1] - [5] - DPL Inc Consolidated tax allocated to Coal-Fired Generation Assets.
[10] = [2] - [6] - DPL Inc Consolidated tax allocated to DP&L-TD.
[11] = [12] - [9] - [10].
[12] = [4] - [8] - DPL Inc Consolidated tax. DPL Inc Consolidated tax calculated as 35.84% * (Operating EBITDA - Depreciation - Interest Expense (Income)).
[13] = [15] - [14].
[14]-[15] Based on internal Company projections.
[16] = [14] - [10].
[17] = [13] + [16].
[18] = [17] - [11].
[19] = [9].
[20] = [18] - [19].
[21] = [22] - [23].
[22]-[23] = Revolver Credit Limit - Short Term Debt of prior year.

EXHIBIT RJM-12

ANALYSIS OF DEBT SERVICE ABILITY WITH RER 2017 – 2026

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	EBITDA	[redacted]									
[1]	Coal-Fired Generation Assets										
[2]	DP&L-TD										
[3]	Other										
[4]	DPL Inc Consolidated Total										
	CapEx										
[5]	Coal-Fired Generation Assets										
[6]	DP&L-TD										
[7]	Other										
[8]	DPL Inc Consolidated Total										
	Estimated Funds Available for Debt Service										
[9]	Coal-Fired Generation Assets										
[10]	DP&L-TD										
[11]	Other										
[12]	DPL Inc Consolidated Total										
	Debt Service										
[13]	Debt Issued by DPL Inc.										
[14]	Debt Issued by DP&L-TD										
[15]	DPL Inc. Consolidated										
[16]	Deficit (Surplus) of DP&L-TD Debt Service										
[17]	DPL Inc Debt Service After Adjusting for DP&L-TD Surplus										
[18]	DPL Inc. Debt Service After Contribution from Other										
[19]	Funds Available for Debt Service from Coal-Fired Generation Assets										
[20]	Shortfall (Surplus)										
	Revolver Available as of Beginning of Year										
[21]	DPL Inc. HoldCo										
[22]	DP&L-TD										
[23]	DPL Inc. Consolidated										

EXHIBIT RJM-12

ANALYSIS OF DEBT SERVICE ABILITY
WITH RER
2017 – 2026

Notes & Sources:
In thousands.
[1] = Operating EBITDA from Exhibit RJM-8 + RER from Exhibit RJM-9.
[2] From internal Company projections.
[3] = [4] - [1] - [2].
[4] = Operating EBITDA from Exhibit RJM-7.
[5]-[6] From internal Company projections.
[7] = [8] - [5] - [6].
[8] From Exhibit RJM-7.
[9] = [1] - [5] - DPL Inc Consolidated tax allocated to Coal-Fired Generation Assets.
[10] = [2] - [6] - DPL Inc Consolidated tax allocated to DP&L-TD.
[11] = [12] - [9] - [10].
[12] = [4] - [8] - DPL Inc Consolidated tax. DPL Inc Consolidated tax calculated as 35.84% * (Operating EBITDA - Depreciation - Interest Expense (Income)).
[13] = [15] - [14].
[14]-[15] Based on internal Company projections.
[16] = [14] - [10].
[17] = [13] + [16].
[18] = [17] - [11].
[19] = [9].
[20] = [18] - [19].
[21] = [22] - [23].
[22]-[23] = Revolver Credit Limit - Short Term Debt of prior year.

EXHIBIT RJM-13

DPL INC. AND DP&L-TD
OUTSTANDING DEBT AS OF DECEMBER 31, 2015

	Amount Outstanding	Issued Amount	Interest Rate	Maturity Date
DPL Inc. HoldCo				
Term Loan	$125,000	$200,000	Variable	5/10/2018
2016 Bonds	$130,000	$450,000	6.500%	10/15/2016
2019 Bonds	$200,000	$200,000[1]	6.750%	10/1/2019
2021 Bonds	$780,000	$800,000	7.250%	10/15/2021
DPL Capital Trust II	$15,571	$20,571	8.125%	9/1/2031
Revolver	-	$205,000	Variable	5/10/2018
DPL Inc. HoldCo Total	$1,250,571	$1,675,571		
DP&L-TD				
2003 First Mortgage Bonds	$445,000	$445,000	1.875%	9/15/2016
2006 Ohio Air Quality	$100,000	$100,000	4.800%	9/1/2036
2015 Ohio Air Quality Series A	$100,000	$100,000	Variable	8/1/2020
2015 Ohio Air Quality Series B	$100,000	$137,800	Variable	8/1/2020
WPAFB Purchase Note (US Gov't)	$18,103	$18,691	4.200%	2/28/2061
Preferred Series A, B, C	$22,851	$22,851	3.793%	N/A
Revolver (PNC)	-	$175,000	Variable	8/24/2015
DP&L-TD Total	$785,954	$999,342		
DPL Inc. Consolidated Total	$2,036,525	$2,674,913		

Notes & Sources:

[1] The $200 million issued amount of the 2019 Bonds was initially part of the 2016 Bonds so is excluded from the total to avoid double counting.
In thousands.
From internal Company data.

EXHIBIT RJM-14

MOODY'S RATINGS TEST
AS OF FEBRUARY 16, 2016

		AEP Company, Inc.		FirstEnergy Corp.		Duke Energy Corporation		DPL Inc.	
	Weight	Ratios	Rating	Ratios	Rating	Ratios	Rating	Ratios	Rating
		[A]		[B]		[C]		[D]	
Interest Coverage	18.75%	5.5	A	3.7	Baa	5.2	A	3	Baa
CF / Debt	37.50%	21.0%	Baa	13.9%	Baa	16.5%	Baa	10.9%	Ba
RCF / Debt	25.00%	16.3%	Baa	11.6%	Baa	11.4%	Baa	10.6%	Baa
Debt / Capitalization	18.75%	43.9%	A	54.7%	Baa	44.7%	A	74.3%	B
Structural Subordination Notching					-1		-1		-3
Indicated Rating			Baa1		Baa3		Baa2		B1
Assigned Rating			Baa1		Baa3		Baa1		Ba3
Notch Difference			0		0		1		1

Notes & Sources:

[A] Moody's Credit Opinion, November 30, 2015.
[B] Moody's Credit Opinion, January 20, 2016.
[C] Moody's Credit Opinion, January 15, 2016.
[D] Moody's Credit Opinion, October 13, 2015.
Interest Coverage = (CFO Pre-WC + Gross Interest Expense) / Interest Expense.
Cash Flow/Debt = CFO Pre-WC / Total DPL Inc. Consolidated Debt.
Retained Cash Flow/Debt = (CFO Pre-WC - Dividends) / Total DPL Inc. Consolidated Debt.
Debt/Capital = Total DPL Inc. Consolidated Debt / Total Capitalization.
Indicated Rating calculated using weights from Moody's report "Regulated Electric and Gas Utilities," December 2013.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 16-0395-EL-SSO
CASE NO. 16-0397-EL-AAM
CASE NO. 16-0396-EL-ATA

PUBLIC

DIRECT TESTIMONY
OF EUGENE T. MEEHAN

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
- ■ **OTHER**

TABLE OF CONTENTS

Page

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, CURRENT POSITION, AND BUSINESS ADDRESS.

A. My name is Eugene T. Meehan. I am a Special Consultant with NERA Economic Consulting ("NERA"). My business address is 1255 23rd Street, N.W., Washington, D.C. 20037.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have over 35 years of experience in advising electric and gas utility companies in the areas of strategic planning, regulatory strategy, power system modeling and financial and economic analysis. Since 1996, I have worked at NERA as a Vice President and Senior Vice President, and now am affiliated with NERA as a Special Consultant. I previously worked at NERA as a Senior Economic Analyst from 1973 to 1980. Before my return to NERA in 1996, I held positions at Deloitte & Touche Consulting Group as a Utility Consulting Partner and at Energy Management Associates, Inc. ("EMA") as a Vice President. I have testified as an expert on electric industry issues before numerous state regulatory commissions (including the Public Utilities Commission of Ohio ("PUCO")), before the Federal Energy Regulatory Commission ("FERC"), the Atomic Safety and Licensing Board, federal courts and arbitration panels. I have also submitted expert affidavits or declarations to the same authorities and in state court and presented the results of regional production simulations to utility Boards of Directors. I hold a B.A. in economics from Boston College, from which I graduated cum laude in 1972. My most recent curriculum vitae, which includes a list of my publications and affiliations, is submitted as Exhibit ETM-1.

Q. DO YOU HAVE EXPERIENCE CONDUCTING ANALYSES AND TESTIFYING WITH RESPECT TO LARGE SCALE PRODUCTION SIMULATION MODELS AND POWER MARKET INFORMATION?

A. Yes. From 1980 through 1994 I was employed by EMA, the company that developed the PROMOD production simulation model. I had a large role in developing the multi-area version of that model, which incorporated the modeling of transmission constraints and was designed to model regional and power pool systems. As a Vice President at EMA, I concentrated on providing consulting service to clients, many using the multi-area version of the PROMOD model. I testified on model validation, development of model inputs and analysis of model outputs. The applications of the model that I helped to implement included projections of marginal and avoided costs, fuel budgets, power sale and margin forecasts, merger-related production cost savings, transmission line economics, generating plant retirement impacts, generation expansion analyses and power pool restructuring analyses. Prior to joining EMA, I worked from 1973 to 1980 at NERA, also using production cost models. After rejoining NERA in 1996, I continued to work on projects that involved regional production cost modeling including analyses of stranded costs, forecasts of market prices, and development of integrated resource plans. I have worked with various production cost models including PROMOD, AURORAxmp ("Aurora"), Plexos and GE MAPS.

Q. CAN YOU BRIEFLY SUMMARIZE YOUR EXPERIENCE IN ANALYZING CAPACITY MARKETS AND CAPACITY PRICES?

A. From 2003 through 2005, I directed a large scale investigation for the three Northeast Regional Transmission Operators ("RTOs") (ISO-NE, NYISO and PJM) of a forward capacity market construct. That work examined the potential for a joint Centralized Resource Adequacy Market ("CRAM"). While a joint CRAM was never implemented, the results of that investigation were a precursor to the individual capacity markets administered by the RTOs. In 2005, I worked for the load interests in New England providing advice in settlement discussions related to the ISO-NE capacity market. In 2009, I advised ISO-NE on capacity market revisions related to buyer-side mitigation. From 2007 through 2014, I advised NYISO on a variety of capacity market issues and directed the development of the Demand Curve in the last three NYISO Demand Curve resets. In connection with NERA's work managing the New Jersey Basic Generation Service ("BGS") Auction and power procurements in Pennsylvania, I regularly examine developments and market conditions in the Reliability Pricing Model ("RPM"), PJM's capacity market construct.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUCO?

A. Yes. I have previously testified before the PUCO on behalf of American Electric Power Ohio ("AEP"), The Dayton Power and Light Company ("DP&L"), and the FirstEnergy Ohio utilities.

Q. PLEASE STATE THE PURPOSES OF YOUR TESTIMONY.

A. The purposes of my testimony are as follows:

- to develop projections of baseline wholesale energy and capacity prices that apply to the various load areas within Ohio;
- to develop projections of wholesale energy and capacity prices that would apply to the various load areas within Ohio in the event that a set of

generating units identified and owned in part by DP&L were to cease operating past 2016 (hereafter, "retirement scenario"[1]); and

- to develop projections of the retail rate impacts to Ohio residential, commercial and industrial customers of changes in wholesale energy and capacity markets under the retirement scenario.

In all cases, my projections cover the ten-year period from 2017 through 2026. The identified set of generating units owned by DP&L and considered in my testimony includes J.M Stuart, W.H. Zimmer, Miami Fort, Killen Station, Kyger Creek, Clifty Creek, and Conesville unit 4 (collectively referred to hereafter as "units"). Note that one unit under consideration, Clifty Creek, is located in Indiana but is owned in part by DP&L and does have an impact on energy and capacity prices for the Ohio load zones.

My NERA colleague, Dr. David Harrison, is testifying as to the impacts to the Ohio economy of the retirement scenario, and he uses various results of my analyses as inputs to his study. These results include estimates of retail rate impacts and information related to Ohio generation changes (i.e., increases or decreases in generation from Ohio power plants as a result of the retirement scenario). It is also my understanding that the baseline energy and capacity prices that I develop will be used by Mr. Jeff Malinak from Analysis Group to assess the financial performance of the identified generating units should they continue to operate.

Q. PLEASE BRIEFLY SUMMARIZE THE RESULTS OF YOUR ANALYSIS OF BASELINE ENERGY AND CAPACITY PRICES.

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[1] The retirement scenario also includes market adjustments to the unit retirements; the specific assumptions underlying these price forecasts are provided in Section IV.

A. My analysis indicates that baseline energy prices will rise from current levels through 2026 at a rate considerably higher than expected inflation. Current prices are at low levels relative to historical prices in real terms. The current prices are a function primarily of low natural gas prices and low variable emission costs for coal generation. As natural gas prices return to levels indicated by long-term forecasts, and as the Clean Power Plan ("CPP") is implemented, the variable costs of generation (both natural gas and coal) will increase significantly in real terms, which will translate into increased wholesale energy prices in the long run. FIGURE 1 below shows in nominal dollars the projected average wholesale energy price for the baseline in the DP&L load area.

FIGURE 1: BASELINE WHOLESALE ENERGY PRICE FORECAST ($/MWH)

REDACTED

Note: All values in nominal dollars.

My analysis also indicates that PJM RPM capacity prices for the RTO region (the area applicable to Ohio generation and load) will increase from the last established result (for delivery year ("DY")[2] 2018/2019) to the first period for which an RPM auction has not yet been held (DY 2019/2020) and will continue to increase at a similar rate through DY 2021/2022. The near-term increase is largely a result of a contraction in the level of excess capacity that PJM acquired in the 2018/2019 RPM Base Residual Auction ("BRA"), which exceeded the historical average and therefore lowered the clearing price in the 2018/2019 BRA. PJM's Capacity Performance ("CP") requirements also should result in capacity price increases relative to historical levels, but are reflected in large part in the 2018/2019 RPM results. Figure 2 below shows in nominal dollars the projected capacity prices for the RTO from DYs 2018/2019 (actual) through 2026/2027.

[2] Delivery years correspond to the period from June 1 through May 31 for which capacity is procured.

FIGURE 2: BASELINE WHOLESALE CAPACITY PRICE FORECAST ($/MW-DAY UCAP)

REDACTED

Note: All values in nominal dollars; all prices correspond to the actual or forecasted BRA RTO price.

II. WHOLESALE ENERGY MARKET

Q. PLEASE BRIEFLY DESCRIBE HOW WHOLESALE ENERGY PRICES ARE DETERMINED.

A. Electric generating units bid their capacity into the PJM day-ahead and real-time energy markets based on their marginal cost to produce a unit of energy. A unit's bid is based on its variable costs including fuel, variable operations and maintenance costs ("VOM"), and emission costs. PJM, the system operator, minimizes system costs by selecting units based on the least-cost security-constrained dispatch to meet load, taking into consideration transmission limits, transmission losses, security-related contingencies and unit-specific dispatch limitations. This process produces spot day-ahead and real-time energy prices for various nodes on the system. Each generating unit is assigned a node, as is each load withdrawal location, and load-weighted average nodal prices are developed for each load zone.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR METHODOLOGY FOR FORECASTING WHOLESALE ENERGY PRICES.

A. Long-term wholesale energy price forecasting generally requires the use of a production cost model, a type of model that simulates this cost minimization process based on available resources and other input data. For this analysis, I used the state-of-the-art production cost model, Aurora, produced by EPIS. The Aurora model has been used by DP&L, AEP, and by consultants for the PUCO staff[3]. The widely-used model provides unit-level hourly dispatch details including generation, fuel costs, VOM costs, and emission costs, and also produces spot energy prices. Implicit in the Aurora model results presented in this testimony are a number of input assumptions that I have made for this proceeding.

Q. CAN YOU PLEASE DESCRIBE IMPORTANT BASELINE INPUT ASSUMPTIONS THAT SUPPORT YOUR WHOLESALE ENERGY PRICE FORECASTS?

A. The Aurora model comes standard with an up-to-date database that includes unit-level and market-level inputs. I rely on the Aurora database for unit-level details including capacity, heat rate, availability, VOM costs, and emission rates. In this analysis, I am running a zonal model which assumes a "pipe-and-bubble" transmission system whereby

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[3] See direct testimony of witnesses Ryan T. Harter and Ralph C. Smith on behalf of the PUCO in Case 10-2929 (available: https://dis.puc.state.oh.us/CaseRecord.aspx?Caseno=10-2929&link=PDC).

zones are connected to each other through interfaces; I rely on the Aurora database for the system's transmission interface limits.

For purposes of this analysis, I have used a number of inputs for reasonableness and consistency with other expert witnesses in this proceeding. I did so based upon my own professional judgment and experience. For consistency with the transmission analysis provided by Mr. Carlos Grande-Moran with Siemens PTI, I updated the Aurora database to include the peak load and total annual energy forecasts from PJM's 2014 Load Forecast Report.[4] I have customized the database's natural gas price forecast to rely on a combination of future prices from the New York Mercantile Exchange ("NYMEX")[5] and from the U.S. Energy Information Administration's ("EIA") 2015 Annual Energy Outlook ("AEO").[6] Future prices are a strong predictor of near-term prices, but low trading volumes in later years result in less reliable estimates; therefore, I assume natural gas prices are equal to Henry Hub NYMEX future prices (as of January 15, 2016) in 2017 and 2018. Beginning in 2019, I trend Henry Hub prices linearly to meet the AEO long-term price forecast in the year 2025, with prices equal to the AEO forecast thereafter. Hence, traded future prices are the basis for the 2017 and 2018 gas price forecast and influence the 2019 through 2024 gas price forecasts significantly. With respect to air-emission prices, I develop price forecasts for sulfur dioxide ("SO_2") emissions and for annual and seasonal nitrogen oxide ("NO_X") emissions under the Cross

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[4] PJM. 2014. *Load Forecast Report*. February. http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report-data.ashx

[5] Daily settlement data for future products downloaded from CME Group, Inc. (available: http://www.cmegroup.com/market-data/settlements.html?utm_source=data_flyout&utm_medium=settlements&utm_campaign=flyout).

[6] U.S. Energy Information Administration (EIA). 2015. *Annual Energy Outlook 2015.* April. http://www.eia.gov/forecasts/aeo/index.cfm

State Air Pollution Rule ("CSAPR") based on NYMEX market prices. As for resource additions and removals, I include only unit retirements that have already been announced in PJM (likely a conservative assumption given the duration of the forecast period) and develop baseline unit addition assumptions consistent with the observed level of new resources that have cleared in recent RPM capacity market auctions. I utilize the coal price information in the Aurora database with the singular exception of Conesville. I was informed by DP&L that Conesville has in place a coal contract that results in the unit facing coal prices above market prices through 2019. I used contract prices provided by DP&L for Conesville through 2019 and prices from the Aurora database thereafter.

Q. HAVE YOU ACCOUNTED FOR ANY POTENTIAL CARBON POLICIES IN DEVELOPING YOUR BASELINE INPUT ASSUMPTIONS?

A. Yes. The U.S. Environmental Protection Agency ("EPA") promulgated its final CPP rule on October 23, 2015 under Section 111(d) of the Clean Air Act, which regulates carbon dioxide ("CO_2") emissions from existing power plants with compliance targets phased in beginning in 2022.[7]

In order to account for the effects of CPP compliance, I adjust my input assumptions for consistency with a recent NERA analysis of the energy market impacts of the CPP using NERA's proprietary N$_{ew}$ERA model. N$_{ew}$ERA is an economy-wide integrated energy and economic model that includes a bottom-up representation of the electric sector, as well as a representation of all other sectors of the economy and households. The model assesses, on an integrated basis, the effects of major policies such

[7] U.S. Environmental Protection Agency. *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*. 80 Fed. Reg. 205 (October, 23 2015). https://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf

as the CPP on individual sectors (e.g., electric energy) as well as the overall economy. It has substantial detail for all of the energy sources used by the economy, with separate sectors for coal production, crude oil extraction, electricity generation, refined petroleum products, and natural gas production. The rule as promulgated allows for some flexibility in developing compliance strategies; the N$_{ew}$ERA results that I use assume that all states choose to comply with EPA's mass-based caps (rather than rate-based targets) and that states develop a system of regional trading where states can trade emission allowances within six multi-state regions consistent with EPA's own regional trading boundaries.

I used the N$_{ew}$ERA modeling results to develop or adjust various important input assumptions that will be affected by CPP compliance. Most significantly, I develop long-run carbon prices for the Aurora modeling based on the relevant regional carbon price as modeled in N$_{ew}$ERA under the mass-based trading scenario. In addition, I account for the effects of the CPP on energy prices (in particular, coal and natural gas prices) in the Aurora model by applying a percentage change to my baseline input assumptions equal to the percentage change in these prices under the CPP against the N$_{ew}$ERA baseline.

I recognize that the Unites States Supreme Court on February 9, 2016 stayed implementation of the CPP, pending the D.C. Circuit's ruling on the merits and the outcome of any petition for certiorari or Supreme Court review.[8] The CPP may or may not survive intact as a result of this judicial process; however, I believe that basing my analysis on the CPP is the best approach right now to representing potential carbon emission regulations. The alternatives—either to assume no federal carbon emission

[8] See February 9, 2016 order in Case No. 15A773 (available: http://www.supremecourt.gov/orders/courtorders/020916zr_21p3.pdf)

regulation through 2026 or to speculate about what alternate form of carbon emission regulation may emerge if the CPP is ordered modified or overturned by the courts—are in my opinion less appropriate.

Q. HAVE YOU PERFORMED ANY CALIBRATIONS IN DEVELOPING YOUR WHOLESALE ENERGY PRICE FORECASTS?

A. Yes. I compared the Aurora energy price forecast for 2017 to the traded forward energy prices as of January 15, 2016. This is the same date used to develop model inputs reflecting gas future prices. Hence, I calibrate the model to the market's expectations using consistent gas and electric traded future prices. The electric forward energy price that is quoted is for the AEP/Dayton Hub. The Aurora model reports prices for the AEP load zone, the DP&L load zone, the FirstEnergy Ohio ("ATSI") load zone and the Duke Energy Ohio and Kentucky ("DEOK") load zone. Using historical PJM day-ahead energy prices for all of these zones and for the AEP/Dayton Hub, I adjust the load zone energy prices from Aurora to the prices at the AEP/Dayton Hub—PJM reports an hourly price for the Hub as well for the load zones. I then compare the adjusted 2017 annual average energy price for each zone from Aurora to the AEP/Dayton Hub annual average forward price for 2017. The calibration indicated that the Aurora model was producing energy prices that ranged from 5% to 10% above the traded forward market. I adjusted the Aurora prices downward by the calculated calibration percentage to reflect this tendency to produce energy prices that were somewhat higher than the traded forward markets indicate. I believe that traded forward energy prices are the best indication of expected short-term spot energy prices and that it is appropriate to calibrate long-term model forecasts to such market information when possible. While models are extremely useful for analyzing price trends relative to changes in loads, resources, fuel prices and emission costs, they are not necessarily as precise in reflecting factors such as the detailed impacts of losses and congestion which will impact actual zonal energy prices. Calibration can adjust for these factors. The results I present in this testimony and pass on to Dr. Harrison and Mr. Malinak reflect calibrated results.

Q. PLEASE PRESENT YOUR BASELINE WHOLESALE ENERGY PRICES.

A. In TABLE 1 below, I show annual average energy prices for each Ohio PJM load zone for the period 2017 through 2026. Figure 3 shows a graphical representation of these prices.

TABLE 1: BASELINE WHOLESALE ENERGY PRICE FORECAST ($/MWH)

REDACTED

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
DP&L										
Duke										
AEP										
ATSI										

Note: All values in nominal dollars.

FIGURE 3: BASELINE WHOLESALE ENERGY PRICE FORECAST ($/MWH)

REDACTED

Note: All values in nominal dollars.

Q. WOULD YOU LIKE TO PROVIDE ANY COMMENTARY ON THESE FORECASTS?

A. Yes. As noted in the summary of results, I am projecting that energy prices will increase significantly in real terms. The increase is to a large extent a result of projected increases in natural gas prices from what are historically low levels as well as the introduction of carbon emission prices with the CPP.

Q. HAVE YOU DEVELOPED ANY OTHER INFORMATION FROM THE AURORA ANALYSIS FOR USE IN THIS CASE?

A. Yes. I have compiled for each of the units the revenue that it would receive as developed by Aurora, the fuel costs as developed by Aurora, the VOM costs as developed by Aurora, and the emission costs as developed by Aurora. I have passed these results to Mr. Malinak for use in his financial assessment of continued operation. In order to develop revenues, Aurora uses zonal prices for the zone in which the units are located. I apply the calibration adjustment to these revenues. Additionally, as I explained above, each generating unit has a PJM node and the revenues it receives are based on nodal prices. I adjusted Aurora revenues from those that would prevail at the load zone, to those that would prevail at the AEP/Dayton Hub. I then adjusted revenues that would prevail at the AEP/Dayton Hub to revenues that would prevail at the PJM node to which each plant is assigned. For this latter adjustment, I utilized the same historical basis adjustment factors utilized by DP&L relating prices at each node to prices at the AEP/Dayton Hub.

III. WHOLESALE CAPACITY MARKET

Q. PLEASE BRIEFLY DESCRIBE HOW WHOLESALE CAPACITY PRICES ARE DETERMINED.

A. In PJM, capacity prices are determined within the capacity market construct called the Reliability Pricing Model. PJM's capacity market is designed to attract adequate resources to maintain reliability, both at the system level and within several constrained areas known as locational deliverability areas ("LDAs"). RPM is a three-year forward capacity market with a multi-auction structure consisting of one base residual auction ("BRA") conducted three years in advance of a DY and three incremental auctions conducted in the period leading up to the DY.[9] The vast majority of capacity in PJM clears the base residual auction; therefore, on a weighted-average basis, the capacity price for any given year tracks very closely with the BRA clearing price. In addition, PJM is transitioning to a new CP market construct. The CP construct will have similar auctions and features as the existing market design.

It is worth noting that the various DP&L units under consideration are located outside of the LDAs in what has historically been a relatively unconstrained region referred to as the RTO region. These units are therefore subject to the RTO price. The reliability target in the RTO region is based on the total PJM load.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR METHODOLOGY FOR FORECASTING WHOLESALE CAPACITY PRICES.

A. I have developed baseline BRA RTO capacity price forecasts for the period from 2017 through 2026 (or for DYs 2016/2017 to 2026/2027). This period includes a number of DYs for which BRAs have already occurred. My methodology for developing price forecasts depends upon whether or not a BRA has already settled,[10] and can be summarized as involving the following steps.

1. Recreate the administratively-defined VRR curve in the annual capacity auction:

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[9] PJM reserves the right to also schedule conditional incremental auctions to procure additional capacity in an LDA to address a reliability problem.

[10] As discussed below, the BRA results for 2016/2017 and 2017/2018 have been supplemented by results from PJM's incremental auctions for those DYs and PJM's transition CP auctions; while BRA results for those DYs are reported herein, they are not utilized in this proceeding.

a. For DYs where planning parameters have already been established administratively (namely, DYs 2016/2017-2018/2019), use the existing parameters; or

b. For DYs where planning parameters have not yet been established administratively (namely, DYs 2019/2020-2026/2027), extrapolate VRR parameters based on tariff guidelines and on expected future market conditions (e.g., load growth).

2. Determine the level of capacity supply that clears the market:

a. For DYs where the BRA has already been settled, use the level of capacity supply that cleared the auction; or

b. For DYs where the BRA has not been settled, assume the level of capacity supply reverts linearly from the DY 2018/2019 level toward the observed three-year average level of excess for the settled BRAs over three DYs (i.e., meets the average in DY 2021/2022) and is equal to the observed average level of excess thereafter. In other words, I assume that new resources are bid into the market in an amount such that the market in the long run clears at a level relative to the capacity target consistent with that which has been recently observed for the RTO.

3. Determine the clearing price for each DY as the point on the VRR curve corresponding to the level of capacity supply determined to clear the market.

Q. ARE YOUR CAPACITY PRICE FORECASTS CONSISTENT WITH THE CURRENT PJM TARIFFS?

A. Yes. On June 9, 2015, FERC approved PJM's CP order, recognizing that the current market design did not provide adequate incentives for resource performance.[11] On November 28, 2014, FERC approved various revisions to the VRR curve and gross Cost of New Entry ("CONE") values as a result of the triennial review process.[12] The impacts of both orders were first incorporated with the 2018/2019 BRA. The associated changes in RPM market-design elements are incorporated in my capacity market forecasts for the relevant period (i.e., beginning with the 2018/2019 BRA).

Q. PLEASE PRESENT YOUR BASELINE WHOLESALE CAPACITY PRICES.

A. In TABLE 2 below, I show annual capacity prices and capacity supply for the RTO region applicable to the PJM BRAs for the 2016/2017 through 2026/2027 DYs. Figure 4 shows a graphical representation of these capacity prices.

TABLE 2: BASELINE WHOLESALE CAPACITY PRICE AND SUPPLY FORECAST: BRA FOR THE RTO REGION

REDACTED

	16/17	**17/18**	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**	**26/27**
Capacity Price ($/MW-day UCAP)											
Capacity Supply (GW UCAP)											

Note: All values in nominal dollars; all prices correspond to the actual or forecasted BRA RTO price.

[11] PJM Interconnection, L.L.C., 151 FERC ¶ 61,208 (2015). http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13899457

[12] PJM Interconnection, L.L.C., 149 FERC ¶ 61,183 (2014). http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13697133

FIGURE 4: BASELINE WHOLESALE CAPACITY PRICE FORECAST: BRA FOR THE RTO REGION

REDACTED

Note: All values in nominal dollars; all prices correspond to the actual or forecasted BRA RTO price.

The forecasts above are for baseline capacity prices as determined in the BRA for each DY. Results prior to the 2019/2020 DY represent actual values. Generally, it would be expected that BRA results for the RTO region would closely approximate the capacity prices that load in the region would pay and that generators in the region would receive. This is not, however, the case for DY 2016/2017 and DY 2017/2018. For those periods, PJM has held CP transition auctions that add $38.17 per MW-day to the price paid by load in 2016/2017, add $28.42 per MW-day to the price paid by load in 2017/2018, and increase the price paid to resources which cleared in the CP transition auction in the RTO region to $134 per MW-day for 2016/2017 and to $151.50 per MW-day for 2017/2018.

Q. WOULD YOU LIKE TO PROVIDE ANY COMMENTARY ON THESE FORECASTS?

A. Yes. The forecasts predict a moderate increase in the baseline capacity price between 2018/2019 and 2021/2022 and more gradual increases thereafter. This is primarily a function of the posited level of excess capacity relative to DY 2018/2019. Historically, the level of excess capacity clearing in the BRA for the RTO region has been variable, and this level was relatively high in DY 2018/2019. I assume that, after DY 2018/2019, the level of excess reverts towards the observed average level for the 2016/2017 through 2018/2019 DYs on a straight line basis, meeting the average in DY 2021/2022. This decreasing trend in excess capacity supply results in rising prices over that period. After DY 2021/2022, the level of excess stabilizes and prices are stable in nominal terms. This stability results in part from the assumed real escalation in natural gas prices, which increases the energy revenue offset used in the calculation of net CONE. I consider a three-year average view of the potential level of excess a superior forecast than one developed using just the most recent year, but also believe that it is appropriate to model a trend from the 2018/2019 actual. Forecasted capacity prices are generally higher than historical values; however, that reflects the significant changes made in the PJM capacity market to reevaluate the VRR curves and to transition from a base capacity product to a Capacity Performance product. Moreover, the forecast is consistent with observations by the PJM Independent Market Monitor ("IMM") that RPM has suffered from price formation issues in recent years. The IMM has found that market design flaws have resulted in prices well below net CONE—or the revenue shortfall the market is designed to compensate—since RPM's inception. "IMM analysis has shown that prices which would result from an RPM construct with its major flaws corrected are close to net CONE" (i.e., higher than recently observed).[13]

IV. POTENTIAL RETIREMENT SCENARIO

Q. HAVE YOU DEVELOPED PRICE FORECASTS UNDER FUTURE CONDITIONS OTHER THAN BASELINE CONDITIONS?

A. Yes. In addition to the baseline forecasts above, I have also developed projections of wholesale energy and capacity prices that would apply to the various load areas within Ohio in the event that the units under consideration were to cease operating past 2016. I use these changes in wholesale capacity and energy markets to develop estimates of the retail rate impacts of retirement for use in the economic impact analysis that Dr. Harrison performs.

Q. DOES THIS SCENARIO INVOLVE OTHER CHANGES IN INPUT ASSUMPTIONS (E.G., MARKET ADJUSTMENTS TO UNIT RETIREMENTS) OTHER THAN THE UNIT RETIREMENTS?

A. Yes. I analyze two cases and present a combined case as the retirement scenario forecast. The first case assumes no market response. The second case assumes increases in transmission import capability into the DP&L and DEOK zones as modeled in Aurora that are roughly commensurate with the amount of capacity that would be retired in each of those zones. The first case shows a very large increase in zonal energy prices as a result of retirement. These price increases would not likely be sustainable and would eventually be mitigated because the divergence between zonal prices and regional prices

[13] Independent Market Monitor (IMM). 2014. *Comments of the Independent Market Monitor on PJM's Capacity Performance Proposal and IMM Proposal.* September. http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_on_PJM%27s_Capacity_Performance_Proposal_and_IMM_Proposal_20140917.pdf

would likely justify economically-driven transmission additions.[14] The addition of transmission import capability to these zones is a logical way to mitigate these impacts from both a capacity and energy perspective; however, the development of such a response will require lead time. I assume that increased import capability would be realized by 2020. Hence, the forecast that I present as the combined case for the retirement scenario is based on no response through 2019 and increases in import capability to the zones beginning in 2020.

Q. HAVE YOU, OR TO YOUR KNOWLEDGE HAVE OTHER WITNESSES, IDENTIFIED THE SPECIFIC TRANSMISSION PROJECTS THAT WOULD PROVIDE FOR SUCH INCREASED IMPORT CAPABILITY?

A. No. While Mr. Carlos Grande-Moran from Siemens PTI examined the reliability impacts of retirement and identified specific transmission projects needed for reliability, the economic transmission enhancement to mitigate the impact of congestion on energy prices was not examined. Hence, no rate impact has been accounted for as a result of transmission additions and the costs of any such facilities are not reflected in the economic impact forecast by Dr. Harrison. As indicated by the very large increases in energy prices in the no-response case for the DP&L and DEOK load zones compared to the single digit percentage increases for the AEP and ATSI load zones, the congestion resulting from the retirements would require an economic response. An expansion of transmission import capability is a logical response. Of course, if this expansion were to prove to be too expensive, an alternative might be that replacement generation would

[14] PJM's Regional Transmission Expansion Plan ("RTEP") process has a provision for approving transmission enhancements that mitigate congestion.

need to be developed within the DP&L and DEOK load zones. The price impact as well as the timing in which the response could be realized would likely be similar as new generation would also require several years of lead time.

V. WHOLESALE ENERGY MARKET IMPACTS

Q. PLEASE PRESENT YOUR RETIREMENT SCENARIO WHOLESALE ENERGY PRICES.

A. In TABLE 3 below, I show annual average energy prices for each Ohio PJM load zone for the period 2017 through 2026. FIGURE 5 shows a graphical representation of these prices. The forecasts are a combination of the no-response case through 2019 and the increased import capability case thereafter. Baseline results are also shown for comparative purposes.

TABLE 3: RETIREMENT SCENARIO WHOLESALE ENERGY PRICE FORECAST ($/MWH)

REDACTED

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Baseline										
DP&L										
Duke										
AEP										
ATSI										
DP&L										
Duke										
AEP										
ATSI										
Increase										
DP&L										
Duke										
AEP										
ATSI										
DP&L										
Duke										
AEP										
ATSI										

Note: All values in nominal dollars.

FIGURE 5: RETIREMENT SCENARIO WHOLESALE ENERGY PRICE FORECAST ($/MWH)

REDACTED

Note: All values in nominal dollars.

VI. WHOLESALE CAPACITY MARKET IMPACTS

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR METHODOLOGY FOR FORECASTING WHOLESALE CAPACITY PRICES UNDER THE RETIREMENT SCENARIO.

A. Forecasting capacity prices under the retirement scenario requires one additional methodological concept in addition to those required in developing my baseline capacity price forecasts, namely the concept of a supply curve shift. This methodological concept applies to Step 2 in the approach summarized in Section III.

1. Recreate the administratively-defined VRR curve in the annual capacity auction.
2. Determine the level of capacity supply that clears the market under retirement:
    a. In order to determine the level of supply that might clear the market under the retirement scenario, I develop a linear approximation of the supply curve slope based on auction information made available by PJM.[15] I then shift this linearly-approximated supply curve inward horizontally by the level of unforced capacity ("UCAP") equal to the total UCAP of the identified DP&L units.[16] The level of capacity supply that clears the market is equal to the point along the y-axis at which the shifted supply curve intersects the VRR curve. Note that the point of intersection is at some level of supply that is greater than the baseline supply less the DP&L units as additional supply clears the market due to an increasing price. Figure 6 below provides a graphical representation of this supply curve shift.
3. Determine the clearing price for each DY as the point on the VRR curve corresponding to the level of capacity supply determined to clear the market:

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[15] A linear approximation of the supply curve is developed based on information made available in PJM's BRA Scenario Analysis. In this document, PJM publishes market equilibria under various scenarios including negative supply shocks. With this information, I am able to identify multiple points on the supply curve and develop a linear segment that should approximate the slope of the supply curve above the market clearing price and quantity.

[16] Note that an *intra-RTO* transmission upgrade, such as the ones assumed under the retirement scenario, does not offset the impact of this supply shock at the RTO region.

a. If the resulting clearing price is above net CONE, I set the clearing price equal to net CONE (i.e., net CONE is treated as an effective price ceiling). Net CONE is the price that PJM calculates as required to induce entry for a representative new generating unit.

I calculate and present wholesale capacity prices under the retirement scenario only for those DYs for which the BRA has not yet been conducted and otherwise assume the capacity price impact is zero. I assume that neither the DP&L nor DEOK load zones become separate LDAs that would clear at higher prices than the RTO region as a result of the retirements. This assumption is consistent with the development of the reliability-required transmission additions that Siemens PTI has identified and the assumption that I make that import limits would be increased into the DP&L and DEOK zones. Were these zones to become LDAs that cleared at a higher price than the RTO region, then capacity price impacts and associated rate impacts would be greater than those I show.

FIGURE 6: ILLUSTRATIVE GRAPHICAL REPRESENTATION OF SUPPLY CURVE SHIFT

REDACTED

Q. PLEASE PRESENT YOUR RETIREMENT SCENARIO WHOLESALE CAPACITY PRICES.

A. In TABLE 4 below, I show annual capacity prices and capacity supply for the RTO region applicable to the PJM RPM BRAs. Figure 7 shows a graphical representation of these capacity prices. Baseline results are also shown for comparative purposes.

TABLE 4: RETIREMENT SCENARIO WHOLESALE CAPACITY PRICE AND SUPPLY FORECAST: BRA FOR THE RTO REGION

REDACTED

	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Baseline								
Capacity Price ($/MW-day UCAP)								
Capacity Supply (GW UCAP)								
Retirement Scenario								
Capacity Price ($/MW-day UCAP)								
Capacity Supply (GW UCAP)								
Increase								
Capacity Price ($/MW-day UCAP)								
Capacity Supply (GW UCAP)								
Increase (% Baseline)								
Capacity Price ($/MW-day UCAP)								
Capacity Supply (GW UCAP)								

Note: All values in nominal dollars.

FIGURE 7: RETIREMENT SCENARIO WHOLESALE CAPACITY PRICE FORECAST: BRA FOR THE RTO REGION

REDACTED

Note: All values in nominal dollars; all prices correspond to the actual or forecasted BRA RTO price.

VII. RETAIL RATE IMPACTS

Q. PLEASE EXPLAIN HOW THE INCREASES IN WHOLESALE ENERGY AND CAPACITY PRICES UNDER THE RETIREMENT SCENARIO WILL BE INCORPORATED INTO RETAIL ELECTRICTY PRICES.

A. Load serving entities ("LSEs")—be they Competitive Retail Electric Service ("CRES") providers or Standard Service Offer ("SSO") providers procuring wholesale supply through full requirements auctions—will be required to provide energy and capacity to meet the requirements of their retail load. The cost (or opportunity cost) of providing these requirements will fall upon these LSEs and will be reflected in their prices. While these LSEs may acquire energy and capacity or hedge energy and capacity through various means, ultimately costs will be based upon spot market energy prices and RPM capacity prices. The cost of acquiring energy in the spot market and acquiring capacity through PJM's RPM will flow through to retail rates in the prices that CRES providers charge customers and the prices at which bidders are willing to supply in SSO auctions. CRES charges will presumably directly reflect retail customer load shapes in their price offers, while SSO prices will be translated into class rates in a way that reflects class load shapes.

Q. PLEASE SUMMARIZE THE STEPS YOU TOOK TO DEVELOP ESTIMATES OF CHANGES IN THE RETAIL ELECTRICITY PRICES FACED BY VARIOUS CLASSES OF OHIO CONSUMERS DUE TO CHANGES IN WHOLESALE ENERGY PRICES.

A. My methodology for estimating changes over time in Ohio consumer electricity prices due to changes in wholesale energy prices under the retirement scenario (as provided in Section V) can be summarized as involving the following steps:

1. calculate the increase in baseline all-hour average wholesale energy prices due to the units' retirement (i.e., subtract baseline wholesale energy prices from retirement scenario wholesale energy prices);
2. apply a shaping factor to the wholesale energy price increase in order to account for the fact that retail customers tend to consume more energy in higher priced hours (I use 4% for residential customer load, 3% for commercial customer load and 2% for industrial customer load based on my professional judgment and experience);

3. apply a loss factor to the wholesale energy price increase (after shaping costs) in order to account for the fact that there are distribution losses associated with retail customer loads (I use 4% for residential customer load, 3% for commercial customer load and 2% for industrial customer load based on my professional judgment and experience); and
4. add the shaping and loss costs calculated in Steps 2 and 3 to the wholesale price increase in order to calculate the impact on retail rates in $/MWH for each customer class and service territory.

Q. PLEASE PRESENT YOUR WHOLESALE-ENERGY-PRICE-RELATED RETAIL RATE IMPACTS.

A. In TABLE 5 below, I show the resulting $/MWH retail price increases for each year, service territory, and customer class due to increases in wholesale energy prices under the retirement scenario. I understand that Dr. Harrison converts these values to percentage increases in baseline retail electricity prices and uses the calculated percentage increases in retail electricity prices, modified to fit the Ohio regions he models, as inputs to his economic impact assessment.

TABLE 5. INCREASE BY CUSTOMER CLASS IN RETAIL ELECTRICITY PRICES INDUCED BY WHOLESALE ENERGY PRICE IMPACTS OF THE RETIREMENT SCENARIO ($/MWH)

REDACTED

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential										
DP&L										
Duke										
AEP										
ATSI										
Commercial										
DP&L										
Duke										
AEP										
ATSI										
Industrial										
DP&L										
Duke										
AEP										
ATSI										

Note: All values in nominal dollars.

Q. PLEASE SUMMARIZE THE STEPS YOU TOOK TO DEVELOP ESTIMATES OF THE CHANGES IN RETAIL ELECTRICITY PRICES FACED BY VARIOUS CLASSES OF OHIO CONSUMERS DUE TO THE CHANGES IN WHOLESALE CAPACITY PRICES.

A. My methodology for estimating changes over time in Ohio consumer electricity prices due to changes in wholesale capacity prices and capacity supply under the retirement scenario (as provided in Section VI) can be summarized as involving the following steps:

1. calculate the percentage increase in the product of the BRA RTO capacity price and capacity supply due to the units' retirement (an increase in the capacity price under the retirement scenario is also associated with a reduction in the amount of capacity clearing the BRA and a reduction in the amount of capacity that each LSE will be required to purchase relative to the aggregate peak load contribution of the customers it serves);

2. calculate an effective increase in capacity price due to the units' retirement by applying the percentage increase calculated in Step 1 to the baseline wholesale capacity price;
3. apply a capacity obligation load factor to the effective increase calculated in Step 2 in order to calculate the impact on retail rates in \$/MW-day for each customer class (I use 40% for residential customer load, 50% for commercial customer load and 80% for industrial customer load based on my professional judgment and experience—note that a lower load factor corresponds to a higher capacity charge per unit of energy); and
4. convert the impact on retail rates by customer class from \$/MW-day to \$/MWH (dividing by 24) and from delivery years to calendar years (averaging the two relevant DYs for each calendar year).

Q. PLEASE PRESENT YOUR WHOLESALE-CAPACITY-PRICE-RELATED RETAIL RATE IMPACTS.

A. In TABLE 6 below, I show the resulting \$/MWH retail price increases for each year, service territory, and customer class due to increases in wholesale capacity prices under the retirement scenario. I understand that Dr. Harrison converts these values to percentage increases in baseline retail electricity prices and uses the calculated percentage increases in retail electricity prices, modified to fit the Ohio regions he models, as inputs to his economic impact modeling.

TABLE 6. INCREASE BY CUSTOMER CLASS IN RETAIL ELECTRICITY PRICES INDUCED BY WHOLESALE CAPACITY PRICE IMPACTS OF THE RETIREMENT SCENARIO ($/MWH)

REDACTED

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential										
Commercial										
Industrial										

Note: All values in nominal dollars.

Q. HAVE YOU CONDUCTED ANY SENSITIVITY ANALYSIS WITH RESPECT TO THE CAPACITY PRICE IMPACT OF THE RETIREMENT SCENARIO?

Yes. The PJM RPM market is difficult to forecast with certainty. Relatively minor changes in the capacity supply offered or in various planning parameters can have noticeable impacts on clearing prices. In order that the PUCO be able to evaluate the effect that different capacity market impacts of retirement would have on the overall economic impacts presented by Dr. Harrison, I have conducted two sensitivities of capacity price impacts—a “low” and “high” price sensitivity case—due to the units’ retirement. I conduct these sensitivities by positing an alternate level of RPM BRA clearing prices under the retirement scenario, determining the associated market-clearing supply, and translating the change in capacity price and supply into retail rate impacts by the methodology described immediately above. For the high price case, I do not treat net CONE as an effective price ceiling; instead, I assume that the market clears at a price that is equal to 115% of net CONE (which would correspond to a clearing supply that is still greater than baseline supply less the units’ capacity). For the low price case, I assume that the market clears at a price that is halfway between the baseline clearing price and the “base” retirement scenario prices (i.e., those presented in Section III). In TABLE 7 below, I show annual capacity prices and capacity supply by retirement scenario sensitivity case for the RTO region and applicable to the PJM RPM BRAs; the baseline is provided for comparative purposes. In TABLE 8, I show the resulting impact on retail rates by retirement scenario sensitivity case calculated according to the methodology described immediately above. The purpose of these additional cases is to provide Dr. Harrison with information that he can use to conduct sensitivities of the overall economic impacts to alternative changes in capacity prices (and subsequent changes in retail rates) under the retirement scenario.

TABLE 7. RETIREMENT SCENARIO WHOLESALE CAPACITY PRICE AND SUPPLY FORECAST BY SENSITIVITY CASE: BRA FOR THE RTO REGION

REDACTED

	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Capacity Price ($/MW-day UCAP)								
Baseline								
RS—low								
RS—mid								
RS—high								
Capacity Supply (GW UCAP)								
Baseline								
RS—low								
RS—mid								
RS—high								

Note: All values in nominal dollars. RS corresponds to retirement scenario. Retirement scenario capacity price and supply are equal to baseline price and supply for DYs before 2019/2020.

TABLE 8. INCREASE BY CUSTOMER CLASS AND SENSITIVITY CASE IN RETAIL ELECTRICITY PRICES INDUCED BY WHOLESALE CAPACITY PRICE IMPACTS OF THE RETIREMENT SCENARIO ($/MWH)

REDACTED

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
RS—low										
Residential										
Commercial										
Industrial										
RS—mid										
Residential										
Commercial										
Industrial										
RS—high										
Residential										
Commercial										
Industrial										

Note: All values in nominal dollars. RS corresponds to retirement scenario.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

1028159.1

NERA
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EUGENE T. MEEHAN
SPECIAL CONSULTANT

Mr. Meehan is a Special Consultant affiliated with NERA. He has over thirty-five years of experience consulting with electric and gas utilities and has testified as an expert witness before numerous state and federal regulatory agencies, as well as appeared in federal court and arbitration proceedings.

At NERA, Mr. Meehan's practice concentrates on serving energy industry clients, with a focus on helping clients manage the transition from regulatory to more competitive environments. He has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. In addition, he has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has experience leading NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory and business strategy, as well as development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

Education

Boston College, BA, Economics, *cum laude*
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	CONSULTANT
2015-	Special Consultant Affiliated with NERA Economic Consulting
	NERA Economic Consulting
1999-2014	Senior Vice President
1996-1999	Vice President
1973-1980	Senior Economic Analyst; Research Assistant
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President

Areas of Expertise

Restructuring/Stranded Cost Recovery

Mr. Meehan has directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulating regulatory filings to accomplish strategy. As part of these assignments, Mr. Meehan facilitated sessions with senior management to set and track filing strategy. Clients include Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing

Mr. Meehan has formulated unbundling strategies, with a specialization in generation pricing. He has advised several utilities in standard offer pricing and has testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement

Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation, with the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before FERC and state regulatory agencies on competitive power procurement. In addition, Mr. Meehan helped to design and implement the New Jersey BGS auction process.

Power Contracts

Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed and testified on the three principal types of power contracts: integrated utility to integrated utility contracts, IPP to utility contract, and integrated or wholesale utility to distribution utility contracts. He has testified in power contracts disputes on behalf of Carolina Power and Light, Duke Power Company, Southern Company, Orange and Rockland Utilities, and Tucson Electric Power. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements

In addition to his expertise on power pooling issues, Mr. Meehan has significant experience with assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets and has designed efficient specifications for retail settlement systems, including the use of load profiling, and examined the risk and cost allocation issues of alternative settlement systems.

Risk Management

Mr. Meehan has advised several large utilities on price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements, as well as provision of price managed service for various terms.

Marginal Costs

Mr. Meehan has provided comprehensive marginal cost analyses for over 25 North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Production Simulation Modeling

Mr. Meehan has extensive experience designing and using production simulation models including PROMOD, Aurora, Plexos and GE-MAPS. He has utilized these models on variety of assignments for over thirty clients and as part of these assignments has validated models and input assumptions.

Power Supply and Transmission Planning

Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes, and the prudence of particular investment decisions.

Generation Strategy

Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling

Mr. Meehan has in-depth working knowledge of the operating, accounting, and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since 1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In NEPOOL, he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to explore the impact of PJM restructuring proposals upon generating asset valuation and examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy, and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies, as well as for various utilities on the impact of pooling arrangements on strategic alternatives.

Representative Assignments

Worked with Public Service Electric & Gas Company (PSE&G) to direct a three year NERA advisory effort on restructuring. Facilitated a two-day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998, worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination, and briefing. Also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999, advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

Worked on separate assignments for a large utility in the Northeast and a large utility in the Southeast, advising on the evaluation of risk management offers from power marketers. The assignments included reviewing proposals, attending interviews with marketers and providing advice on these, and the developing analytical software to evaluate offers.

Worked with government of Ontario beginning in 2004 to help design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. Supervising NERA's portfolio-based economic evaluation on behalf of the Ontario Ministry of Energy.

Testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a soon-to-be-created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. In addition, this effort involved the review of more than 100 power contracts in the WECC.

Directed NERA's efforts, on behalf of the electricity regulator in Ireland, to design an RFP and implementation process for the purchase of 500 Mw of new generating capacity in 2003. NERA advised on the RFP, the portfolio evaluation method, and the power contract and also conducted the economic evaluation.

Reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Submitted testimony before FERC on behalf of Southern Company Service.

Worked with Baltimore Gas and Electric (BG&E) to conduct a one and one-half year consulting assignment that involved providing restructuring advice. The project began in March/April 1998 with senior management discussions and workshops on plan development and filing strategy. Advised BG&E in the development of testimony, rebuttal testimony, and public information dissemination. Worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits and in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, advised BG&E on generation valuation and unregulated generation business strategy.

Directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards, and unit contracts to determine the optimal mix of instruments to manage price risk.

Testified for XCEL Energy on the use of competitive bids for new generation needs. Examined whether XCEL was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life-of-facility contracts, in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

Advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. Defended the First Energy shopping credit proposal.

Advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. Testimony focused on retail competition in gas and electric commodity markets.

Directed NERA's effort to train selected representatives of a major European power company in American power marketing and risk management practices. The project involved numerous meetings and interviews with power marketing firms.

Led NERA's effort to advise the New England ISO on the development of an RTO filing. Examined performance-based ratemaking for transmission and market operator functions.

Examined ERCOT power market conditions during the period of time from 1997 to 1999 and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

Advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. Involved forecasting of the unbundled wholesale cost-of-service and market prices, as well as development of a regulatory strategy for gaining approval of contract restructuring and the transfer of generation from regulated to EWG states.

Performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions, and recommendations concerning credit exposure monitoring, credit evaluation processes, and credit requirements.

Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, a portion of the UK wholesale settlement system.

Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members and the evolution of full requirement power wholesale power contracts into contracts that preserve Oglethorpe's financial integrity and are suitable for a competitive environment.

Developed long run marginal and avoided costs of natural gas service, as well as avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

Review of power contracts and testimony in numerous power contract disputes

Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM and cogeneration, as well as to develop integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first of its kind in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presented strategic and financial results in order to convince senior management to initiate negotiations for the incentive plan.

Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP-based marginal capacity costs.

Provided testimony on behalf of the investor-owned electric utilities in New York State, concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool as part of various consulting assignments and in connection with the development of production simulation software.

Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company’s buy-back tariffs.

Developed and presented a two-day seminar delivered to electric industry participants in the UK (prior to privatization), outlining the structure and operation of power pools and bulk power market transactions in North America.

Benchmark analysis and FERC testimony of PGE’s proposed twelve-year contract between PG&E and Electric Gen LLC (contract value in excess of $15 billion).

Responsible for NERA’s overall efforts in advising New Jersey’s Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions (the 2002 auction involved $3.5 billion, and the 2003 and 2004 auctions involved over $4.0 billion).

Publications, Speeches, Presentations, and Reports

Capacity Adequacy in New Zealand's Electricity Market, published in *Asian Power*, September 18, 2003

Central Resource Adequacy Markets For PJM, NY-ISO AND NE-ISO, a report written February 2004

Ex Ante or *Ex Post*? Risk, Hedging and Prudence in the Restructured Power Business, The Electricity Journal, April 2006

Distributed Resources: Incentives, a white paper prepared for Edison Electric Institute, May 2006

Restructuring Expectations and Outcomes, a presentation presented at the Saul Ewing Annual Utility Conference: The Post Rate Cap and 2007 State Regulatory Environment, Philadelphia, PA, May 21, 2007

Making a Business of Energy Efficiency: Sustainable Business Models for Utilities, prepared for Edison Electric Institute, August 2007

Perspectives on Ownership Issues for Traditional Generating & Alternative Resources: Should we allow utilities back in the market or limit ownership to merchants? A presentation presented at the Energy in the Northeast Conference sponsored by Law Seminars Intl., October 18, 2007

Restructuring at a Crossroads, presented at Empowering Consumers Through Competitive Markets: The Choice Is Yours, Sponsored by COMPETE and the Electric Power Supply Association, Washington, DC, November 5, 2007

*Competitive Electricity Markets: The Benefits for Customers and the Environmen*t, a white paper prepared for COMPETE Collation, February 2008

The Continuing Rationale for Full and Timely Recovery of Fuel Price Levels in Fuel Adjustment Clauses, The Electricity Journal, July 2008

Impact of EU Electricity Competition Directives on Nuclear Financing presented to: SMI – Financing Nuclear Power Conference, London, UK, May 20, 2009

Using History As A Guide, a presentation presented at the Electric Power Research Institute (EPRI) Conference: Electricity Pricing Structures for the 21st Century, July 14 – 15, 2011, Nashville, TN

Testimony

Forums

Arkansas Public Service Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Maine Public Utilities Commission

Minnesota Public Service Commission

Nevada Public Service Commission

New York Public Service Commission

New York State Department of Environmental Conservation

Nuclear Regulatory Commission – Atomic Safety and Licensing Board

Oklahoma Public Service Commission

Public Service Commission of Indiana

Public Utilities Commission of Ohio

Public Utilities Commission of Nevada

Public Utilities Commission of Texas

Public Utilities Commission of New Hampshire

United States District Court

United States Senate Committee on Energy and Natural Resources

Various arbitration proceedings

Clients

American Electric Power Company

Arkansas Power & Light Company

Baltimore Gas & Electric

Carolina Power & Light Company

Central Maine Power

Consolidated Edison Company of New York, Inc.

Dayton Power and Light Company

Florida Coordinating Group

Houston Lighting & Power Company

Minnesota Power and Light Company

Nevada Power Company

Niagara Mohawk Power Corporation

Northern Indiana Public Service Company

Oglethorpe Power Corporation

Pacific Gas and Electric Company

Power Authority of the State of New York

Public Service and Electric Company

Public Service Company of Oklahoma

Sierra Pacific Power Company

Southern Company Services, Inc.

Tucson Electric Power Company

Texas-New Mexico Power Company

Recent Expert Testimony and Expert Reports

Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996.

Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998.

Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999.

Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999.

Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999.

NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.

Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999.

Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999.

Rebuttal Testimony on behalf of Niagara Mohawk, PSC Case No. 99-E-0681 Before the New York State Public Service Commission, November 10, 1999.

Arbitration deposition on behalf of Oglethorpe Power Corporation, last quarter of 1999.

Direct Testimony Before the Public Utilities Commission of Ohio on behalf of FirstEnergy Corporation, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 99-1212-EL-ETP re: Shopping Credits.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0990, February 25, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., State of Connecticut, Department of Public Utility Control, Docket No.: 00-01-11, April 28, 2000 and June 30, 2000.

Testimony on behalf of Texas-New Mexico Power Company, Fuel Reconciliation Proceeding before the Texas PUC, June 30, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the New Hampshire Public Service Commission, Docket No.: DE 00-009, June 30, 2000.

Rebuttal Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, November 22, 2000.

Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, January 19, 2001.

DETM Management, Inc. Duke Energy Services Canada Ltd., And DTMSI Management Ltd., Claimants vs. Mobil Natural Gas Inc., And Mobil Canada Products, Ltd., Respondents. American Arbitration Association Cause No. 50 T 198 00485 00, August 27, 2001.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) Docket No.: EX01050303, October 4, 2001.

Direct Testimony Before the Federal Energy Regulatory Commission on behalf of Pacific Gas and Electric Company, Docket No.: ER02-456-000, November 30, 2001.

Fourth Branch Associates/Mechanicville vs. Niagara Mohawk Power Corporation, January 2002 (Expert Report).

Arbitration Deposition on behalf of Oglethorpe Power Corporation, March 2002.

Direct Testimony and Deposition Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, July 16, 2002.

Rebuttal Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, August 13, 2002.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, in the matter of the Application of Nevada Power Company to Reduce Fuel and Purchased Power Rates, PUCN Docket No. 02-11021, November 8, 2002 and subsequent Deposition Testimony.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, Docket No. 03-1014, January 10, 2003.

Direct Testimony Before the Public Utility Commission Of Texas on behalf of Texas-New Mexico Power Company, Application Of Texas-New Mexico Power Company For Reconciliation Of Fuel Costs, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, PUCN Docket No. 02-11021, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company, Docket No. 03-1014, May 5, 2003.

Testimony Before the Public Service Commission of New York on behalf of Consolidated Edison Company of New York, Inc., Case No.: 00-E-0612, September 19, 2003.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 12, 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 12, 2004.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, May 28, 2004.

Direct Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, January 22, 2004.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, April, 2004.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 9, 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 7, 2005.

Expert Report on behalf of Oglethorpe Power Corporation, March 23, 2005.

Arbitration deposition on behalf of Oglethorpe Power Corporation, April 1, 2005.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's December 2005 Deferred Energy Case.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, January 13, 2006.

Remand Rebuttal for Public Service Company of Oklahoma before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200200038, **Confidential**, March 17, 2006

Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, April 18, 2006.

Cross-Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, May 22, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, Docket No. 06-01016, June 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386, December 22, 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 05-0315, December 29, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2007 Deferred Energy Case, January 2007.

Declaration Before the State of New York Public Service Commission, on behalf of Consolidated Edison Company of New York, Inc.'s Long Island City Electric Network, Case 06-E-0894 – Proceeding on Motion of the Commission to Investigate the Electric Power Outage and Case 06-E-1158 – In the Matter of Staff's Investigation of Consolidated Edison Company of New York, Inc.'s Performance During and Following the July and September Electric Utility Outages. July 24, 2007.

Direct Testimony Before The Public Utilities Commission of Colorado, In The Matter of the Application of Public Service Company of Colorado for Approval of its 2007 Colorado Resource Plan, April 2008.

Answer Testimony Before the Public Utilities Commission of the State of Colorado on behalf of Trans-Elect Development Company, LLC, and The Wyoming Infrastructure Authority, Docket No. 07A-447E, April 28, 2008.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Application of Sierra Pacific Power Company d/b/a/ NV Energy Seeking Acceptance of its Eight Amendment to its 2008-2007 Integrated Resource Plan, Docket No. 10-02023.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's 2008 Deferred Energy Case, February 2009.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2008 Deferred Energy Case, February 2009.

Direct Testimony Before the Public Utilities Commission of Texas, on behalf of Entergy Texas, Inc. Docket No. 33687, April 29, 2009.

Direct Testimony Before The Public Utilities Commission Of Nevada On Behalf of Nevada Power Company D/B/A Nevada Energy, 2010 – 2029 Integrated Resource Plan, June 26, 2009.

Before the Public Service Commission of New York, Case 09-E-0428 Consolidated Edison Company of New York, Inc. Rate Case, Rebuttal Testimony, September 2009.

Direct Testimony Before the Public Utilities Commission of Nevada on Behalf of Sierra Pacific Power Company's 2009 Deferred Energy Case, February 2010.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2009 Deferred Energy Case, February 2010.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2010 – 2029 Integrated Resource Plan, Docket No. 09-07003, July 2010.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Eighth Amendment to its 2008 – 2027 Integrated Resource Plan, Docket No. 10-03023, July 2010.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Application of Nevada power Company d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2010-2029, including authority to proceed with the permitting and construction of the ON Line transmission project, Docket No. 10-02009.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Petition of Nevada Power Company d/b/a NV Energy requesting a determination under NRS 704.7821 that the terms and conditions of five renewable power purchase agreements are just and reasonable and allowing limited deviation from the requirements of NAC 704.8885, Docket No. 10-03022.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company d/b/a NV Energy, 2010 Deferred Energy Case, Docket No. 10-03003, filed August 3, 2010

Rebuttal Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company d/b/a NV Energy Electric Department, 2010 Deferred Energy Case, Docket No. 10-03004, filed August 3, 2010

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 11-03 __ 2011 Electric Deferred Energy Proceeding, February 2011.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 11-03 __ 2011 Electric Deferred Energy Proceeding, February 2011.

Testimony Before the Atomic Safety and Licensing Board, Nuclear Regulatory Commission, In the Matter of Entergy Nuclear Operations, Inc., Dockets Nos. 50-247-LR and 50-286-LR, March 30, 2012.

Rebuttal Testimony Before the Public Utilities Commission of Ohio, In Support of AEP Ohio's Modified Electric Security Plan, Case No. 10-2929, May 11, 2012.

Prefiled Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 12-03 __ 2012 Electric Deferred Energy Proceeding, February 2012.

Prefiled Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 12-03 __ 2012 Electric Deferred Energy Proceeding, February 2012.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 13-03 __ 2013 Electric Deferred Energy Proceeding, February 2013.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 13-03 __ 2013 Electric Deferred Energy Proceeding, February 2013.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 14-02 __ 2014 Electric Deferred Energy Proceeding, February 2014.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 14-02 __ 2014 Electric Deferred Energy Proceeding, February 2014.

January 2015

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 16-0395-EL-SSO
CASE NO. 16-0397-EL-AAM
CASE NO. 16-0396-EL-ATA

DIRECT TESTIMONY OF

MARK E. MILLER

- □ **MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION**
- □ **OPERATING INCOME**
- □ **RATE BASE**
- □ **ALLOCATIONS**
- □ **RATE OF RETURN**
- □ **RATES AND TARIFFS**
- ■ **OTHER**

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THE DAYTON POWER AND LIGHT COMPANY

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark E. Miller. My business address is 1065 Woodman Drive, Dayton, Ohio, 45432.

Q. By whom and in what capacity are you employed?

A. I am employed by the AES US Services, LLC ("AES Services") as the Vice President of Ohio Generation for Dayton Power & Light ("DP&L")

Q. How long have you been in your present position?

A. I assumed my present position on November 18th, 2014. My prior position was as the AES Vice President of United Kingdom and Ireland Markets from April 2009 – November 2014, which included commercial and development responsibilities for a portfolio of coal, gas and wind generation assets in the United Kingdom and Ireland.

Q. What are your responsibilities in your current position?

A. I am responsible for the safe, efficient and environmentally-compliant operations of DP&L-operated competitive generating assets and represent the Company in its interests in the co-owned units with Dynegy and AEP.

Q. Will you describe briefly your educational and business background?

A. I received my operational training through the US Navy Nuclear Program from August 1979 through October 1988. I continue to pursue a finance degree through distance learning and have completed various executive leadership programs throughout my time with AES. Working for the AES Corporation for over 26 years, I have filled numerous senior management roles, which include overall responsibility for the safe and efficient operation of a range of technologies including coal, gas, hydro, wind, solar and energy storage generation assets as well as transmission and distribution.

Q. What is the purpose of this testimony?

A. The purpose of my testimony is to describe the generating units included in the Company's proposed Reliable Electricity Rider ("RER") in its Electric Security Plan ("ESP") proceeding. I will: 1) describe the features of each generating unit and 2) discuss the generating units' competitive position in the deregulated markets they compete in.

II. <u>DESCRIPTION OF DP&L'S GENERATING UNITS</u>

Q. Please identify the generating units the Company included in its ESP/RER filing.

A. Those units are listed below and include Company ownership %:

- Stuart Plant Units 1-4 and Diesels (35%)
- Killen Unit 2 and Combustion Turbine ("CT") (67%)
- Zimmer Unit 1 (28.1%)
- Miami Fort Units 7 and 8 (36%)
- Conesville Unit 4 (16.5%)
- Ohio Valley Electric Corporation ("OVEC") (4.9%)

Q. Please describe the generating units that are in the RER request.

A. All are coal units that use pulverized coal and are equipped with low-nitrogen oxide ("NO_x") burners that minimize the formation of NO_x during the combustion process. Additionally, all units are fitted with selective catalytic reduction equipment ("SCR") to further reduce the emissions of NO_x during operation. All units are equipped with electrostatic precipitators, which typically reduce the emission of particulate matter by >99% and flue gas desulfurization ("FGD") systems that reduce the emissions of sulfur dioxide ("SO_2"). The FGD systems give the units a wider range of commercial flexibility by allowing them to utilize lower-cost, higher-sulfur coals.

The Stuart plant is located in Aberdeen, Ohio. It has 4 individual supercritical coal-fired units rated at 577 MW_{net} each for a total plant capacity of 2,308 MW_{net} and 4 General Motors diesels units rated at 10 MW_{net} in total. Units 1 through 4 were placed into service in 1971, 1970, 1972 and 1974, respectively. The Stuart diesels were placed in service in 1969.

The Killen plant is located in Wrightsville, Ohio. The plant has a single 600 MW_{net} coal-fired unit and a combustion turbine rated at 18 MW_{net} that were placed in service in 1982. Stuart and Killen are operated by DP&L.

The Zimmer plant is located in Moscow, Ohio, and it consists of one supercritical unit rated at 1,320 MW_{net} that was placed in service in 1991. Miami Fort Units 7 and 8 are located in Miami Township, Ohio. Each unit is rated at 510 MW_{net} and they were placed in service in 1975 and 1978 respectively. The plants are operated by Dynegy.

Conseville Unit 4 is located in Conesville, Ohio. The unit is rated at 780 MW_{net} and was placed in service in 1973. The plant is operated by Amercian Electric Power (AEP).

OVEC owns and operates the Kyger Creek Station in Cheshire, Ohio and the Clifty Creek Station in Madison, Indiana with a combined rated capacity of 2,109 MW_{net}.

OVEC was created in 1952 by a group of investor owned utilities (referred to as the "Sponsoring Companies" or "Owners") to meet the electric power needs for the uranium enrichment facilities and processes for the Atomic Energy Commission located near Portsmouth, Ohio. An Inter-Company Power Agreement ("ICPA") controls the operations of these plants by OVEC and the Sponsoring Companies. The ICPA was amended in August 2011 and extends through June 30, 2040. Consistent with the ICPA, DP&L is entitled to its share of the power benefits of the OVEC units equaling 4.9% or approximately 103 MW of OVEC's output. DP&L is responsible for 4.9% of the costs and liabilities associated with its 4.9% ownership share of OVEC.

Q. Is the Company the owner and operator of all of the plants that it is proposing to include in the ESP and RER?

A. No. The Company co-owns the base-load coal units (Stuart, Killen, Zimmer, Miami Forts, Conesville and OVEC) with its co-owners. The Company operates Stuart and Killen Stations. The other base load coal units are operated by the co-owners.

Q. What is your role with respect to the DP&L units included in its filing?

A. I am responsible for the operations of the DP&L-operated generating units (Stuart and Killen) in addition to the long-term planning for both capital investments and Operations and Maintenance ("O&M") costs. For Zimmer, Miami Fort, and Conesville, the operator of those plants is responsible for the day-to-day operations. I am, however, a member of the Engineering and Operating Committee, which includes representatives of each of the owners of those units. On the Committee, I am kept informed of both the operating status of the units as well as the review and approval of the capital investment and O&M budgets as prescribed under the co-owner operation agreements. This involvement allows DP&L to review, approve and provide input and feedback to the other owners of the co-owned generating units. With respect to OVEC, I am a member of the OVEC Board of Directors meaning that I represent DP&L at OVEC Board meetings and vote on certain decisions.

Q. Have DP&L's generating assets operated reliably?

A. Yes. However, during the past several years, given extraordinarily low PJM capacity rates, DP&L has been stretched financially in its ability to fund investment beyond the minimum necessary to keep its units running. While the recent PJM capacity rates have increased for the next few years, outturn capacity rates still fall short of those required to achieve industry standard performance levels for this technology.

III. <u>ROLE OF THE GENERATING UNITS IN DP&L'S PORTFOLIO</u>

Q. How do the generating units compete in the market?

A. Historically, all of DP&L's coal assets have been base-load units and among the lowest cost, most reliable units in the system. However, more restrictive environmental legislation in the past decade has continued to require significantly more investment and resulted in increased operational complexity and costs that have proven to be difficult to recover from the competitive market - particularly for coal-based units which often pursue lower quality coals to remain competitive in the face of inadequate capacity rates. Additionally, the evolution of a deregulated market in Ohio, which has forced DP&L's assets to compete in the same market with other regulated regional players, has resulted in a very challenging businesses environment that significantly increases the vulnerability to early retirement despite the capability of these flexible plants to operate well into the

2030's. Although most of these external pressures tend to weigh more heavily on the coal-fired units due to their broad cost basis and operational restrictions with environmental compliance investment, there is a continuing pressure on peaking assets as well because their business model is premised on the PJM capacity market valuation, which in the recent past has shown to be very unpredictable.

Q. Please describe the investment challenges in light of the current market conditions.

A. Power generating assets are long-life investments that require significant capital to construct, operate and maintain over their life cycles. Investors need clarity over the long term to ensure that their investment will be returned within a reasonable period and with reasonable certainty. Recent experience within the PJM system has shown both a lack of consistency in the value of long-life assets and an inability to deliver consistent financial return over a reasonable investment time period. PJM's reliability pricing model ("RPM") fails to provide pricing for capacity more than three years out, making it very difficult for plant owners to predict the ability to fund investment needs. Added to historically low commodity prices and continued uncertainty as to energy policies, it is very difficult for plant owners to see a future where flexible, fuel-diverse assets can continue to be part of a sustainable energy plan for Ohio. As a result, DP&L's investment decisions are very short-term in nature.

Q. Can you describe the importance of coal-fired generation plants to the reliability of the system?

A. Yes. Electricity generation is part of critical infrastructure upon which the consumer relies heavily every day and is part of the fabric of our daily lives. Given the limited ability to store electricity on a broad competitive basis, real-time delivery is required from assets that need large financial commitments and must be capable of operating across a wide range of conditions. The need for the broad capability of coal assets, in the context of a fully diversified fuel strategy, was shown during the Polar Vortex of 2014 where many gas units experienced loss of gas supply in preference to gas required for heating. The ability of coal based units to have fuel stored on site (contrary to gas which cannot be stored in large quantities) strengthens a diversified energy supply strategy and improves the reliability of the energy supply system.

Q. If DP&L's plants you identify were to be shut down, would that increase the risks of system failures?

A. Yes, shutting down those plants would increase substantially the risks of a system failure, particularly during extreme weather events. Again, during the recent Polar Vortex, DP&L was very close to implementing rolling blackouts. A service interruption – particularly during an extreme weather event – can have serious consequences. The closure of those plants would significantly increase those risks.

Q. Has PJM acknowledged that reliability of the system is at risk in cold-weather events?

A. Yes. In an August 20, 2014 document titled "PJM Capacity Performance Proposal," PJM stated in the first paragraph of the executive summary:

> Last winter's generator performance—when up to 22 percent of PJM capacity was unavailable due to cold weather-related problems—highlighted a potentially significant reliability issue. PJM's analysis shows that a comparable rate of generator outages in the winter of 2015/2016, coupled with extremely cold temperatures and expected coal retirements, would likely prevent PJM from meeting its peak load requirements.

Q. What is the expected life of the DP&L units described in this testimony?

A. All of the assets mentioned in this testimony are capable of operating into the 2030's and should be part of an energy policy that promotes strong elements of fuel diversity and operational flexibility as the energy industry transitions to a more sustainable platform in the coming decades. Though new technologies are emerging (e.g., renewables such as wind, solar, biomass) that drive the economy towards a more sustainable basis, DP&L's view is that coal and gas plants will be required well into the 2030's to provide dispatchable capacity to fill in those gaps when non-dispatchable capacity is not available. The DP&L plants fill an important value gap in the energy market structure and will continue to do so for some time to come, provided of course that they remain economically viable. However, short-term aberrations in the market, as we are currently seeing with volatile commodity prices, need to be counterbalanced by an element of financial stability whereby investors like DP&L are reasonably assured that it can make those large investments with a degree of prudence and cost sensitivity that allows it to deliver its goal of continuing to deliver safe, reliable, sustainable energy to its customers. Through its investment decisions, DP&L seeks to strike a fair balance between managing through market volatility and having the confidence to ensure that its units are capable of meeting customers' needs.

Q. Given current market expectations, can these power plants be maintained in a prudent manner to operate safely and reliably beyond 2030?

A. The DP&L units have been maintained to an acceptable standard to date despite the extraordinarily low PJM capacity rates in the recent past. While the recent PJM capacity rates have increased for the next few years, outturn capacity rates still fall short of those required to achieve industry standard performance levels for this technology. Furthermore, all of the coal assets face significant investment requirements in the next decade due to existing and proposed environmental regulations, which are currently embedded in the Company's long-term investment planning profile. These regulations include the Coal Combustion Rule ("CCR") and Effluent Limitation Guidelines ("ELG") that came into force this year as well as proposed rulemaking under Section 316(b) of the Clean Water Act. Additional details on these environmental issues are in Company Witness Collier's testimony.

Q. Please discuss the Company's views on the potential retirement of the RER units and also what effect an approved RER would have on this view.

A. Without an RER, the DP&L coal plants are and will continue to be financially stressed. Without an approved RER, the plants will experience further restrictions in both capital investment and O&M, which will probably have a negative impact on plant performance. Over the medium term, lower capital investment and O&M expenditures translate directly into lower unit performance (higher outage rates and less competitive capability), which will make the plants even more financially stressed and less able to deliver safe, reliable energy. Without an RER, the risk of premature asset retirement increases dramatically, which will be further exacerbated by the fact that starting January 1, 2017 the generating units will be fully compensated from the wholesale energy market with no other means of cost recovery or support. Continued operations of, and investment in, these generating units will be based on prudent financial decisions for an asset competing in a fully competitive market. If the economics will not support continued operations, then eventually the units will need to be retired at a time when their contribution to the energy supply system is technically feasible and still necessary.

Q. Please discuss the viability of the plants to continue operations in the long-term.

A. The coal fired plants are capable of operating into the foreseeable future if they receive the required O&M and capital investments. Even though some of these plants are over 40 years old, their operating lives can continue so long as the plants receive the proper investment and maintenance.

Q. What is the Company's view on the planned or future retirement dates of the coal fired units included in its RER filing?

A. Given that the generating units must operate in a competitive market, the units must earn a sufficient risk-adjusted return to justify long-term continued operations. Short-term operations can continue if the units' marginal revenue exceeds their marginal costs and therefore contribution to fixed costs are being made. Longer term, however, continued investment and continued operations will be based on the overall economic viability of the plants competing in a wholesale energy market.

Q. What effect would the RER have on both the short term and long term viability of these generating units?

A. In the long term, the physical condition of the plants will ultimately determine their useful lives and retirement dates. In the shorter term, a RER arrangement would make it very probable that these generating units would continue operations through the term of the RER.

Q. Do the challenging conditions that you describe cause DP&L to face a decision as to these plants' future?

A. Yes. The conditions described in this testimony will cause DP&L to consider carefully whether some or all of the coal-fired plants should be retired. In the absence of a stability charge, those plants are at increased risk of being closed.

Q. Does this conclude your direct testimony?

A. Yes.