OCC EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan.	)	Case No. 16-395-EL-SSO
In the Matter of the Application of The Dayton Power and Light Company for Approval of Revised Tariffs.	)	Case No. 16-396-EL-ATA
In the Matter of the Application of The Dayton Power and Light Company for Approval of Certain Accounting Authority Pursuant to Ohio Rev. Code § 4905.13.	)	Case No. 16-397-EL-AAM

DIRECT TESTIMONY
OF
MATTHEW I. KAHAL

On Behalf of the
The Office of the Ohio Consumers' Counsel
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November 21, 2016

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APPENDIX A: Qualifications of Matthew I. Kahal and Past Testimony

I. QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Matthew I. Kahal. I am employed as an independent consultant retained by the Office of the Ohio Consumers' Counsel ("OCC") to address certain issues in this docket. My business address is 1108 Pheasant Crossing, Charlottesville, VA 22901.

Q2. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A2. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration included industrial organization, economic development, and econometrics.

Q3. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A3. I have been employed in the area of energy, utility, and telecommunications consulting for the past 35 years, working on a wide range of topics. Most of my work during my consulting career has focused on electric utility integrated planning, power plant licensing, environmental compliance issues, mergers, and utility financial issues. I was a co-founder of Exeter Associates, Inc. ("Exeter"), and from 1981 to 2001 was employed as a Senior Economist and Principal. During that time, I took the lead role at Exeter in performing cost of capital and financial studies. In recent years, the focus of much of my professional work has expanded to include electric utility markets, power supply procurement, and industry restructuring.

Prior to entering consulting, I served on the Economics Department faculties at the University of Maryland (College Park) and Montgomery College, teaching courses on economic principles, development economics, and business. A complete description of my professional background is provided in Appendix A.

Q4. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE UTILITY REGULATORY COMMISSIONS?

A4. Yes. I have testified before approximately two dozen state and federal utility commissions, federal courts, and the U.S. Congress in more than 400 separate regulatory cases. My testimony has addressed a variety of subjects including fair rate of return, resource planning, financial assessments, load forecasting, competitive restructuring, rate design, purchased power contracts, environmental compliance, merger economics, and other regulatory policy issues. These cases have involved electric, gas, water, and telephone utilities. A list of these cases is set forth in Appendix A, with my statement of qualifications.

Q5. WHAT PROFESSIONAL ACTIVITIES HAVE YOU ENGAGED IN SINCE LEAVING EXETER AS A PRINCIPAL IN 2001?

A5. Since 2001, I have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental controls, cost of capital, and other regulatory issues. Current and recent clients include the U.S. Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal Energy Regulatory Commission, Connecticut Attorney General, Pennsylvania Office of Consumer Advocate, the Ohio Consumers' Counsel, New Jersey Division of Rate Counsel, Rhode Island Division of Public Utilities, Louisiana Public Service Commission, Arkansas Public Service Commission, the Maryland Public Service Commission, the Maine Public Advocate, the New Hampshire Consumer Advocate, the Maryland Department of Natural Resources, and the Maryland Energy Administration.

Q6. HAVE YOU PREVIOUSLY TESTIFIED ON THE SUBJECTS OF ELECTRIC RESTRUCTURING, TRANSITION TO COMPETITION, AND RETAIL DEFAULT SERVICE?

A6. Yes. I have testified on these topics on numerous occasions during the past ten to 15 years. This includes the design of programs to provide generation supply service for those retail electric customers requiring default service. During the past three years, I testified before the Public Utilities Commission of Ohio (the "PUCO") in the Electric Security Plan ("ESP") cases involving AEP Ohio (Case No. 13-2385-EL-SSO), Duke Energy Ohio (Case No. 14-841-EL-SSO), and the three FirstEnergy Utilities (Case No. 14-1297-EL-SSO).

II. OVERVIEW AND SUMMARY

A. Purpose and Summary of Testimony

Q7. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A7. I have been asked by OCC to address certain issues pertaining to the filing in this case by Dayton Power and Light Company ("DP&L" or the "Utility"). The principal purpose of my testimony is to evaluate the Utility's proposed ESP versus the results under a Market Rate Offer ("MRO"). Because the test is a comprehensive analysis of the proposed ESP in the aggregate, I incorporate the findings and recommendations from other OCC witnesses that have a bearing on the merits of this ESP and in particular the proposed new rate riders.

In addition to the ESP versus MRO test, I have been asked by the OCC to address certain other issues addressed in the Utility's application. These issues include the Utility's request for a Distribution Modernization Rider, a Reconciliation Rider, and a Clean Energy Rider.

Q8. PLEASE DESCRIBE YOUR UNDERSTANDING OF DP&L AND THE FILINGS MADE IN THIS CASE.

A8. DP&L is a distribution and transmission electric utility owned by DPL, Inc., which in turn is owned by AES Corporation. At the present time, DP&L also owns non-regulated generation supply assets, but pursuant to the PUCO's directive and its own plan, it has stated that it intends to transfer these assets to a corporate affiliate by January 1, 2017.[1] Consequently, after this transfer takes place, the Utility will operate as a pure delivery service utility, and my testimony assumes that will be the case.

On February 22, 2016, DP&L originally filed this ESP case. That filing proposed an ESP time period covering January 1, 2017 through December 31, 2026, i.e., a period of ten years. On October 11, 2016, the Utility amended its application for an ESP covering a seven-year period, January 1, 2016 to December 31, 2023.

The Utility claims that its proposed ESP will provide greater customer benefits than the MRO alternative in the long-term on both quantitative and qualitative grounds.

On October 11, 2016, DP&L amended its application and sought approval of a new Distribution Modernization Rider ("DMR"), which intends to address DPL, Inc.'s and DP&L's financial integrity needs.[2] The DMR proposal would collect from utility distribution customers $145 million per year over seven years, or $1.015 billion over the ESP. My testimony addresses the merits of this proposal

[1] Case No. 13-2420-EL-UNC, *In the Matter of the Application of The Dayton Power and Light Company for Authority to Transfer or Sell its Generation Assets*, Finding and Order, September 17, 2014.

[2] The DMR could more accurately be called a "Credit Support Rider" since the DMR funds will not actually be used to cover the revenue requirements of any distribution modernization projects (and indeed none have been proposed). The funds could be used by the Utility for any purpose, including (and perhaps mostly) paying dividends to DP&L's parent. Nonetheless, to avoid confusion over terminology I use the stated title of "DMR" per the Utility's filing.

along with alternatives to address financial integrity and credit quality, which I believe are both much lower in cost to customers and more reasonable from a fairness standpoint.

Q9. WHAT IS YOUR UNDERSTANDING OF THE ESP V. MRO TEST?

A9. Approval of an ESP by the PUCO requires that the utility demonstrate that its proposed ESP is more favorable, in the aggregate, for its customers, than the MRO alternative. This has been referred to as the "ESP versus MRO statutory test," and how that test has been evaluated has been the subject of considerable dispute in previous ESP cases. The full wording of this test is stated in R.C. 4928.143(C) (1), and this is what I am referencing as "the test."

Q10. WHAT STANDARDS OR CRITERIA HAVE THE PUCO USED IN THE PAST IN APPLYING THE STATUTORY TEST?

A10. The PUCO in past cases has considered three categories of costs and benefits in its application of the statutory test for the ESP versus the MRO:

- the SSO generation prices for customers;
- other quantifiable customer impacts; and
- qualitative attributes of the proposed ESP.[3]

[3] *See e.g.*, Case No. 12-1230-EL-SSO, Order and Opinion, at pages 55-57.

The ESP benefits included in the test must be those "incremental" for the proposed ESP. Benefits resulting from a previous ESP or from some other source (e.g., a previous rate case settlement) should not be included in the test.

Q11. WHAT FINDINGS DID DP&L REACH CONCERNING THE ESP VERSUS MRO TEST?

A11. The Utility presents its analysis under the statutory test for the proposed ESP in the October 31, 2016 testimony of witness R. Jeffery Malinak. He acknowledges that under the Utility's proposed Competitive Bidding Process ("CBP"), the ESP and an MRO would be expected to produce the same SSO generation pricing, i.e., in either case the same wholesale auction process would be used.[4,5]

Witness Malinak concedes that the DMR proposal would cost customers in excess of $1 billion over the term of the ESP, but he sets forth two scenarios to address that cost: (a) the exact same DMR would be approved in connection with an MRO; and (b) the DMR and its costs could only be implemented as part of an ESP, not with an MRO. The first scenario effectively removes the DMR issue from the ESP test, in essence making the statutory test meaningless.[6] Under the second scenario, he seems to acknowledge that the ESP fails the quantitative test by the $1 billion charge to customers. He notes that the ESP also includes other

[4] Direct Testimony of R. Jeffrey Malinak ("Malinak Testimony"), at 56-65 (October 31, 2016).

[5] Id., at 59-60.

[6] Id., at 60.

riders, but he asserts that these other riders would also be approved by the PUCO under an MRO.[7]

Despite the $1 billion "failure" of the proposed ESP in the test under the second scenario, Mr. Malinak asserts that the ESP passes the statutory test based on qualitative factors. The claimed principal alleged benefit of the proposed ESP is that the DMR protects the Utility's financial integrity and credit quality enabling it to provide reliable service and make needed infrastructure investments including for grid modernization. His other asserted qualitative benefits are outlined briefly on pages 62 – 63 of his testimony.[8]

Q12. WHAT ARE YOUR MAIN FINDINGS CONCERNING THE PROPOSED DMR AND ESP?

A12. Based on my review, I have reached the following conclusions:

(1) Contrary to Witness Malinak's analysis, the as-filed ESP proposal fails the statutory ESP versus MRO test with net customer harm in excess of $1 billion over seven years (tentatively, $1.035 billion of net customer harm and possibly more). There are not offsetting qualitative benefits for customers. There are also other much lower cost and more reasonable ways of addressing financial

[7] Id., at 61.

[8] Id., at 62-63.

integrity for DP&L if and when DP&L's financial integrity actually is at risk.

(2) The proposed ESP will result in significant economic harm to the Dayton regional economy by increasing the cost of utility service, draining purchasing power from consumers and impairing the competitiveness of local businesses.

(3) The centerpiece of the amended ESP filing is the DMR. This rider will be a massive burden for residential customers, increasing rates over the life of the ESP for a typical customer consuming 1,000 kWh per month by $980 for a customer. In addition to these direct charges, residential customers will undoubtedly be impacted indirectly by the DMR charges to local businesses, schools, hospitals, government facilities, etc. as some of these costs are passed through to residential consumers.

When such impacts are considered, a typical residential customer will likely face a total impact on the order of perhaps $1,500 or more over the ESP-term. This substantial impact to customers is on top of DP&L's base rate case request of $65 million annually.

(4) It seems clear that one of the principal purposes of the proposed DMR is to financially support the DP&L/DPL, Inc. generating units due to the weak cash flow the Utility believes those units will

provide over time. I therefore conclude that the DMR will function as a transition charge.

(5) The need for a DMR is supported through allegations by Utility witnesses Jackson and Malinak that DP&L and DPL, Inc. are financially stressed with weak and vulnerable credit ratings. I agree with their assessment of financial weakness for DPL, Inc. and I agree with their assertions that certain prompt action is needed to shore up, improve, and protect credit ratings of DPL, Inc. and DP&L. However, I strongly disagree that the proposed DMR, and the massive burden it places on captive customers, is reasonable, necessary, fair, or appropriate in remedying DPL, Inc.'s or DP&L's financial situations.

(6) Much of the support for the amount of funding needed through the DMR is based on the seven-year financial projections prepared by the Utility. Those projections incorporate some unreasonable and even puzzling assumptions that tend to understate the DP&L earnings and cash flow. This overstates the need for DMR. Consequently, those projections should not be relied upon to determine the need or appropriate amount of the DMR.

In fact, I find that the $145 million DMR per year, if approved by the PUCO, would provide significantly excessive returns on equity ("ROE") for DP&L during each of the proposed ESP's seven years. Using the Utility's projection of its equity balances, those ROEs will be in the 20 to 27 percent range, or about 33 to 38 percent if we use the Utility's claimed distribution rate base from its pending rate case.

(7) There are reasonable and less costly alternatives to the burdensome and harmful DMR.

(8) The financial problems experienced by DPL, Inc. have nothing to do with DP&L providing regulated distribution service to customers. Rather, the financial problems are being caused by a combination of the financial and economic weaknesses surrounding the DPL, Inc. coal-plant fleet and the excessive leverage incurred by AES Corporation and assigned to DPL, Inc. in connection with the financing of the 2011 merger.

The DMR is being proposed as a charge to utility customers for the dual purposes of supporting the DPL, Inc. generation assets (and therefore a transition charge), and (b) subsidizing the DPL, Inc. merger-related debt forced on it by AES Corporation (and therefore counter to prior DP&L commitments to the PUCO).[9]

(9) It seems apparent from the filing that the after-tax DMR funds collected from customers would simply pass through DP&L (the regulated utility) to the unregulated DPL, Inc. The effect is to

[9] See response to IGS-4-1 for documentation of merger-related debt.

massively subsidize the profits of AES Corporation and its shareholders. In effect, the DMR is a reward to AES Corporation for engaging in a highly risky and leveraged financing plan for its merger on the backs of utility customers. Not only is this simply improper, it would seem to violate AES Corporation's commitment to the PUCO as part of its approval of the 2011 merger.[10]

(10) While the billion dollars to be collected from customers has been called a "DMR", 100 percent of these dollars will become pure (pre-tax) profits to AES Corporation. No grid modernization investments or projects have been identified in this ESP let alone proposed. Moreover, none of the dollars will be used as an offset to the grid modernization revenue requirement for the new investment. That is, customers will be charged both the revenue requirements for grid modernization investments (if any such projects go forward) and the $1 billion DMR. Thus, the DMR is simply a subsidy to AES Corporation and has little or no nexus to any actual grid modernization projects.

[10] *In the Matter of the Application of the AES Corporation, Dolphin Sub Inc., DPL Inc. and The Dayton and Power and Light Company for Consent and Approval for a Change of Control of The Dayton Power and Light Company*, Case No. 11-3002-EL-MER, Finding and Opinion, November 22, 2011, at 9.

Q13. WHAT RECOMMENDATIONS ARE YOU PROPOSING CONCERNING THE APPLICATION OF THE STATUTORY TEST IN THIS CASE?

A13. I conclude that the as-filed ESP does not provide customers with quantified benefits and cost savings as compared with the alternative of an MRO. As a result, the PUCO should modify the ESP filing to reduce its cost to customers commensurate with the cost of an MRO. Alternatively, the PUCO could direct the Utility to pursue an MRO. The as-filed ESP should be rejected because it will cost customers $1.035 billion and provide insufficient qualitative benefits to offset such costs. Moreover, the ESP should also be rejected for including improper transition charges (Rider DMR, the Reconciliation Rider, the Clean Energy Rider) and permitting the utility to use customer money (through distribution charges) to subsidize the unregulated parent and ultimate corporate parent.

My testimony identifies alternative actions that can and should be taken by AES Corporation management to address the credit quality concerns of DP&L. After all, it is the responsibility of AES Corporation to ensure that DP&L fully meets its public utility responsibilities and operates in a financially sound manner. However, if the PUCO finds that a DMR type of customer support arrangement is merited, I set forth two alternatives in my testimony that are far lower in cost and less burdensome for customers than the Utility proposal.

If the PUCO does approve a DMR in some form designed to enhance the profits of DP&L, I recommend that it be subject to the Significantly Excess Earnings Test ("SEET").

Q14. DOES YOUR EVALUATION OF THE STATUTORY TEST RELY ON THE TESTIMONY OF OTHER WITNESSES?

A14. Yes. I rely on OCC witnesses Williams and Effron concerning the proposed DIR.

Q15. YOU ARE OPPOSED TO THE PROPOSED DMR. PLEASE SUMMARIZE YOUR POSITIONS ON THE OTHER ESP ISSUES THAT YOU ADDRESS IN YOUR TESTIMONY.

A15. Reconciliation Rider:

The Utility is proposing a Reconciliation Rider to collect from customers a requested deferred regulatory asset related to its entitlement in the Ohio Valley Electric Corporation ("OVEC"). The estimated value of this cost deferral is about $20 million (inclusive of interest) through December 31, 2016, which is essentially the amount by which the costs of the OVEC entitlement have exceeded the PJM wholesale market value of the OVEC power supply during that recent historical period. The Utility now seeks to collect that amount from utility customers through a rider.

However, I find no indication that this accounting deferral treatment has been approved by the PUCO or that the PUCO intended recovery of that historic shortfall. The proposed rider should be rejected. There is no basis for charging customers for the over-market costs of the OVEC entitlement.

Clean Energy Rider:

The Utility in this case also has proposed a Clean Energy Rider. Based on the description in the filing, it appears that this rider is intended mostly to provide cost recovery for certain costs associated with environmental compliance for the legacy coal plants that will be divested, not the environmental compliance costs of the Utility itself for distribution service. Utility customers should not pay for the environmental compliance costs incurred by unregulated generation, whether these costs are in fact coal plant environmental retrofits, new investment in renewable resources, or emission allowances. The Clean Energy Rider, as proposed, is improper and just another utility customer subsidy of unregulated operations. I therefore urge its rejection. And the Utility has not identified, let alone proposed, any such projects. So the need for this rider is at best premature and should be proposed as a stand-alone rider when, and if, the Utility has a specific project to submit.

The DIR:

My testimony incorporates the recommendations on the DIR sponsored by OCC witnesses Williams and Effron as part of the comprehensive ESP versus MRO test. These witnesses do not support the Utility's proposal for this new rider.

Witness Williams specifically recommends rejection of this proposed rider as improper and inconsistent with Ohio policy.

The Term of the ESP:

Finally, I note that the ESP is proposed for a seven-year period. While I recommend against ESP approval, if the PUCO does approve an ESP in this docket, I recommend that it follow past practice in most previous ESP cases and limit it to three years. I recommend this time period due to the inherent uncertainty (and the shortcomings) associated with the financial projections and to provide more effective and relevant PUCO oversight. There are a number of new riders, tariff changes, and a CBP plan proposed in this case. I believe that it would not be desirable to approve these arrangements for seven years, with only limited interim review. To the extent these ESP features are approved, they should be approved only for three years to provide an opportunity for full review after gaining some operational experience and to properly take into account changing circumstances, Utility and customer needs, and experience.

Q16. SHOULD THE PUCO APPROVE THE UTILITY'S ESP PROPOSAL IN THIS CASE?

A16. No. The concept of the ESP has outlived any purpose it may have served for customer protection (if it ever did protect customers) under Senate Bill 221. It operates now as circumventions of both the market pricing intended in 1999 under Senate Bill 3 and the regulation of monopoly distribution service under Revised

Code Chapter 4909. And to provide the benefits of competitive pricing to consumers, an ESP is not needed. The MRO will serve consumers just fine with the benefits from the competitive market.

The SSO based upon a wholesale auction can be accomplished through the MRO. In this regard, the PUCO Chairman at the time wrote a concurring opinion to propose eliminating the electric security plan as soon as 2015:

> The fundamental, structural changes that have occurred since 2011, including resolving generation ownership and corporate separation of all investor owned utilities, eliminates the need for the ESP or MRO filing…. For these reasons, the requirement that such filings be made should be eliminated from the statute starting in 2015 or at the time 100% of the Standard Service Offer (SSO) load is secured at wholesale auction.[11]

The PUCO may modify an ESP. Modifications to the Utility's plan should include restructuring the ESP so that the SSO is provided through an MRO instead.

Under an MRO, much of the added costs that customers are being asked to pay would be eliminated. These charges would then be collected through base distribution rates as they should be under traditional utility regulation. This would save customers money and is consistent with the fact that the Utility is

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[11] *In the Matter of the Commission's Investigation of Ohio's Retail Electric Service Market*, PUCO Case 12-3151-EL-COI, Concurring Opinion at 3 (March 26, 2014).

offering standard service through a competitively bid auction, as envisioned under a market rate offering.

B. Testimony Outline

Q17. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A17. Section III discusses the proposed DMR, explaining why it is improper and sets forth various alternatives. These are alternatives that can be implemented by Utility (and parent) corporate management without requiring massive subsidies from Utility customers. Section IV presents my evaluation of the ESP versus MRO test, focusing mostly on the most important components of the filed ESP (i.e., the DMR, the DIR, the Clean Energy Rider, and the Reconciliation Rider). This section discusses both the aspects of the ESP subject to quantification and the other aspects of the ESP that might be considered qualitative factors. In Section V, I provide as summary of my testimony, findings, and recommendations.

III. THE DMR PROPOSAL IS UNREASONABLE AND IS A TRANSITION CHARGE THAT IS NOT PERMITTED IN OHIO.

Q18. WHAT IS THE DMR PROPOSAL AND HOW HAS THE DOLLAR AMOUNT BEEN DETERMINED?

A18. Witness Jackson describes the DMR proposal and the basis for its size on pages 12 -19 of his testimony. The rider would be an annual charge of $145 million to utility distribution customers over seven years, or a total of $1.015 billion. The starting point in determining this target revenue amount was to develop a set of financial projections for DP&L and its parent, DPL, Inc., over the seven-year period 2017 – 2023 (i.e., balance sheets, income statements, cash flow statements, and resulting credit metric measures). Mr. Jackson calculates the DMR revenues that would be needed to achieve the Moody's Rating Service ("Moody's") credit rating standard for an investment grade credit rating for DPL, Inc. The specific metric that he targets is the ratio of cash flow to debt.[12]

While his testimony discusses the credit metrics and financial projections for both DP&L and its parent, DPL, Inc., I interpret his credit metric/DMR analysis as focusing just on DPL, Inc. This is because DP&L is already an investment grade rated company for its secured debt. In other words, there is no demonstration in his testimony that the $145 million per year (or any DMR amount) would be needed for the DP&L credit metrics if the Utility were to be considered on a

[12] Direct Testimony of Craig L. Jackson ("Jackson Testimony"), October 11, 2016, at 14.

stand-alone basis. Thus, the basis for charging utility customers for the DMR is the notion that the DP&L and DPL, Inc. credit ratings are in some manner linked together. To put it differently, DP&L's credit ratings and financial integrity are "held hostage" to the DPL, Inc. financial weakness and massive excess debt leverage.

Q19. HOW DOES WITNESS MALINAK'S ANALYSIS DIFFER FROM THAT OF WITNESS JACKSON?

A19. They are generally similar, and I assume that they used consistent data input assumptions. Mr. Malinak, however, provides greater detail than Mr. Jackson concerning credit metrics for both DP&L and DPL, Inc. In addition, he shows the financial projections (and the resulting credit metrics and implied ratings) with and without the DMR revenue.

Q20. BEFORE DISCUSSING THE DMR ANALYSIS, PLEASE DESCRIBE HOW IT WILL IMPACT UTILITY CUSTOMERS.

A20. The proposed DMR would impose a massive burden on customers. Using the proposed customer class allocations shown on Utility Witness Hale's Exhibit CEH-1, I calculate that on average the DMR would increase residential rates by $0.017 per kWh. Consequently, for a residential customer consuming 1,000 kWh per month, the total seven-year cost would be an increase in distribution charges of about $980. Overall, it appears that the increase in distribution rates from the DMR, on average, would be about 40 percent. Further, it should be noted that the

Utility has a pending request to collect from customers a $65 million distribution base rate increase (Case No. 15-1839-EL-AIR).[13] If the DMR and the base rate requests both are approved, customers will see in early 2017 a total increase in distribution rates of $210 million. This clearly constitutes a massive increase in the DP&L customer rates.

Moreover, there would be other impacts of DP&L's proposed DMR that would affect residential customers. Witness Hale's exhibit allocates about $64 million of the DMR to residential customers and the remaining $81 million to non-residential customers (i.e., commercial establishments, hospitals, manufacturers, schools, government offices, and so forth). The DMR charges to these non-residential customers will be additional business operating costs that they will attempt to pass through to their own customers (or taxpayers in the case of government). To a large extent these customers will be the households in the DP&L service territory. It is unrealistic to assume that non-residential customers would simply absorb these additional electric service costs from the DMR. In the case of schools and government offices there is no way for them to raise additional revenue other than passing through these cost increases to their residents.

I assume illustratively that non-residential customers will pass through half of their DMR costs to local household consumers through higher prices for locally-supplied goods and services or higher taxes. If this were to occur, the total impact

[13] Please note that my testimony takes no position on the base rate request.

on the residential customer consuming 1,000 kWh per month would increase from the direct cost of about $980 to a total direct and indirect cost of about $1,600. While these total impact figures are just illustrative, the point is that the ultimate burden on the average residential customers from the DMR is likely to be well over $1,000.

As my testimony will discuss further, these customer burdens are particularly troubling given that the DMR is not needed and seems to be designed to enhance the profits of the ultimate parent, AES Corporation. That is, not a single dollar of the $1.015 billion DMR charge will cover or be used to defray any of the DP&L utility cost of service. Some of the funds may be used for investment purposes, but it will not be used to reduce the cost of that investment to consumers. That is, the Utility will collect from customers both the DMR charges and the full revenue requirement associated with all DP&L utility investment.

Q21. IS THERE A POTENTIAL FOR THE DMR TO HARM THE DP&L SERVICE AREA ECONOMY?

A21. Yes, very much so. The DMR will drive up the cost of living for residential customers and the cost of doing business in the region served by DP&L. A higher cost of living drains purchasing power from consumers and therefore constrains their ability to spend on locally-supplied goods and services. This will reduce economic activity, incomes, and employment in the region. For businesses, the higher operating costs from the DMR will reduce their competitiveness in regional, national, and global markets. Through multiplier effects, these higher operating costs will impair regional economic activity and economic development.

Simply put, this unwarranted $1.015 billion charge to captive customers for the proposed DMR will have significant adverse impacts on the Dayton area economy. The PUCO should consider these effects when assessing the DMR.

Q22. AT PAGE 12, WITNESS JACKSON STATES THAT THE DMR IS NOT INTENDED TO SUPPORT THE DPL, INC. GENERATION BUSINESS. DO YOU AGREE?

A22. No. As his testimony makes clear, the purpose of the DMR is to increase (substantially) the operating cash flow of DPL, Inc. and to increase over time its debt leverage. Debt balances can be reduced as dividends from DP&L to DPL, Inc. (which is equity) to replace debt. Mr. Jackson's testimony makes it clear that the DMR revenue is needed to replace the inadequate cash flow provided by the generation assets. Specifically, at page 8 of his testimony he cites to four factors that have contributed to the weakened outlook and therefore the alleged need for the DMR: (1) weak load growth that presumably causes a slow growth in utility revenue, (2) the termination of the Service Stability Rider ("SSR") in September 2016 due to an Ohio Supreme Court decision, (3) lower revenues for the generation assets due to weak prices in the PJM capacity market, and (4) lowered margins on the energy sales from the coal plants due reduced natural gas prices. Taken together, these four factors indicate that financial weakness from the generation assets is truly the driver of the need for the DMR, according to Mr. Jackson.

The first factor, weak distribution sales growth, is actually of relatively minor importance and ultimately has little effect on the cash flow outlook. This is in part because the rate setting process captures the level of sales in determining the size of any rate increase a utility would receive. This should be addressed in the current base distribution rate case, so I must discount the importance of that factor as a driver.

The second factor, the recent termination of the SSR, is generation related because the SSR existed to help support DP&L's generation. By raising the issue of the SSR Mr. Jackson also seems to be implying that the DMR is merely a replacement for the stricken SSR. This should be an issue of concern to the PUCO because of the Ohio Supreme Court ruling that overturned the Utility's retail stability rider.

The last two factors clearly are linked to the economic and financial performance of the generation assets in a very direct manner. They are the reason why generation supply earnings and cash flow are weak relative to the full cost of service for those assets. Thus, from Mr. Jackson's testimony it is clear that the purpose of the DMR is to compensate for the weak financial performance of the generation assets owned by DPL, Inc.

His testimony discusses a further concern relating to generation assets. At page 14 he notes that the credit rating agencies tend to discount the cash flows from the unregulated generation due to the inherent uncertainty associated with that cash flow. This uncertainty and the "discount" associated with the generation cash flow is a driver of the size of the DMR proposed by Mr. Jackson. Thus, the DMR, by financially supporting the generation assets (compensating for their inherent weakness), functions as an transition charge, just like the transition charge the Ohio Supreme Court struck down.

Q23. ARE THERE ANY OTHER DRIVERS OF THE ASSERTED NEED FOR THE DMR?

A23. Yes. Both DP&L and DPL, Inc. presently have excess amounts of debt relative to total capital. This excess debt weakens credit metrics because interest payments on the debt reduce cash flow (and earnings) and the debt level itself is the denominator in the cash flow to debt ratio, a key metric used by credit rating agencies. The excess debt leverage problem is far more severe at the DPL, Inc. level than at DP&L. At this time, DPL, Inc. consolidated has about $2.0 billion of total debt, with $1.2 billion being at the holding company level and the other $800 million being that of DP&L, the utility.[14]

[14] Source: Exhibit RJM-18.

Q24. DOES DP&L HAVE EXCESS LEVERAGE?

A24. Yes, to some degree. In Case No. 13-2420-EL-UNC, the PUCO targeted an improvement in the DP&L capital structure to include a minimum equity ratio of 50 percent. Based on my experience, this is a typical and reasonable electric utility capital structure that should support a solid investment grade credit rating. DP&L should be able to achieve that target within a reasonable period of time through the normal retention of utility earnings. The Utility simply does not require a DMR to achieve that balance sheet strength improvement. Thus, the DMR does not seem to be needed to support DP&L's financial soundness and credit quality when DP&L is viewed on a stand-alone basis and as a pure utility.

Q25. DPL, INC. APPEARS TO HAVE A MORE SEVERE EXCESS LEVERAGE PROBLEM. WHAT ACCOUNTS FOR THAT?

A25. An important contributing factor causing the excess debt is unquestionably from the AES Corporation acquisition of DPL, Inc. in 2011. AES choose to finance the acquisition as an all cash transaction instead of an exchange of stock or even a combination of stock and cash. The cash nature of the transaction necessitated the issuance of massive amounts of new debt because AES lacked the cash on hand. As part of the merger financing arrangements, DPL, Inc. issued $1.25 billion of new debt.[15] This merger financing decision, imposed on DPL, Inc. by AES Corporation, is clearly a major reason why DPL, Inc. has excess debt leverage and weak credit ratings, and therefore an important reason supporting the asserted

[15] See the response to IGS-INT-4-1.

need for the $1.015 billion DMR being proposed. In other words, customers are being asked today to pay for merger financing from five years ago.

Q26. DOES THE DPL, INC. MERGER DEBT PROBLEM IMPLICATE ANY PUCO ORDER?

A26. Yes, it does. In its order in Case No. 11-3002-EL-MER (November 22, 2011), the PUCO approved AES Corporation's acquisition of DPL, Inc. and DP&L subject to certain conditions and commitments from the applicants. The order at paragraph 19(d) mentions the applicants' commitment not to collect from utility customers certain merger-related costs:

> Applicants agree that neither the costs incurred directly related to the negotiation, and closing of the merger nor any acquisition premium shall be eligible for inclusion in rates and charges applicable to retail electric service by DP&L.

The $1.25 billion in debt financing was incurred by DPL, Inc. in connection with and to facilitate the closing of the merger. That debt is a major reason why the DMR is being requested, or at a minimum, the merger debt certainly increases the dollar size of the DMR request. It would appear that the request for the DMR is inconsistent with the commitment made by AES Corporation, DPL, Inc., and DP&L and accepted by the PUCO as part of its merger approval not to charge customers for costs pertaining to the 2011 merger closing. In this case, the "cost" is the credit quality that the Utility alleges requires remediation with massive customer cash contributions.

In summary, I have identified two principal underlying factors that have been used to support the DMR request – (a) weak earnings and cash flow from the generation assets that requires supplementation by the DMR, and (b) the massive merger-related debt incurred in 2011 by DPL, Inc. to support an all-cash acquisition. Neither is an acceptable reason for requesting this burdensome financial support from the captive distribution utility customers in order to subsidize AES Corporation shareholders.

Q27. YOU IDENTIFIED REASONS THAT HAVE BEEN USED TO SUPPORT THE DMR. DOES IT MATTER AT THIS POINT IN TIME WHY IT IS NEEDED AND WHAT ARE THE UNDERLYING CAUSES?

A27. Yes, I believe these underlying reasons are highly relevant. This is because there are legitimate issues of customer versus shareholder equity raised by the DMR proposal. The PUCO should be concerned by the inherent unfairness of this burdensome request. Moreover, as my testimony explains below, there are alternatives to the DMR that can address financial integrity for DP&L that involve management and shareholders bearing more of the responsibility.

Q28. YOU HAVE BEEN DISCUSSING CREDIT RATINGS. WHAT ARE THE CURRENT CREDIT RATINGS FOR DPL, INC. AND DP&L?

A28. Mr. Jackson provides the current Fitch, Standard and Poor's ("S&P") and Moody's credit ratings for both DPL, Inc. and DP&L at page 7 of his testimony. He reports that DPL, Inc. is rated B+/BB/Ba3 from Fitch, S&P and Moody's respectively. These ratings are below investment grade. For DP&L, the ratings are BBB/BBB-/Baa2 from the same three rating agencies. These are investment grade ratings for the Utility's secured debt. However, for both companies, the outlook from the rating agencies is "Negative."

Mr. Jackson expresses concern that based on current trends and the rating agencies' stated outlook both companies are vulnerable to possible downgrades. Witness Malinak reaches a similar conclusion and further emphasizes that the DP&L credit ratings are linked to those of DPL, Inc. It is for that reason that the DMR has been designed primarily to shore up the credit metrics and over time the balance sheet of DPL, Inc., not DP&L utility. So under the DMR it is reasonable to expect that DPL, Inc. will be the ultimate recipient of the lion's share of the (after-tax) revenue collected from utility customers.

Q29. DO YOU AGREE WITH THESE WITNESSES THAT THIS CREDIT RATING PROBLEM NEEDS TO BE ADDRESSED?

A29. Yes. It is important that DP&L maintains an investment grade credit rating so that it may access capital markets on reasonable terms, as needed. There are, however, a variety of actions other than the proposed DMR that can contribute to achieving this result that I discuss below. Beyond protecting DP&L's credit quality, utility customers do not have an interest in the business success of the unregulated business ventures of DPL, Inc. (including the generation assets) and therefore should not be saddled with those costs. Nor should utility customers have an interest in or be required to prop-up the profits of the unregulated AES Corporation.

Q30. SHOULD THE PUCO VIEW THE FINANCIAL PROJECTIONS SET FORTH BY WITNESSES JACKSON AND MALINAK AS RELIABLE AND A BASIS TO SET RATES TO BE COLLECTED FROM CUSTOMERS?

A30. No, I have some serious concerns with those projections, and I therefore question their usefulness and reliability, particularly when used for rate setting as proposed in this case. Mr. Jackson at page 22 asserts, without any support presented, that DP&L is no longer required to transfer to an affiliate its generation assets. The Utility would not provide the OCC with the basis for that assertion.[16] This assertion appears to be inconsistent with what the PUCO has ordered.

Based on this unsupported assertion, Mr. Malinak and Mr. Jackson have prepared and presented their financial projections with the generation assets being retained within DP&L even though it still appears that it is part of the DP&L business plan to transfer those assets to an affiliate "genco" owned by DPL, Inc. This modeling

[16] Response to OCC-INT-303.

assumption may not be important for the DPL, Inc. consolidated projections, but it does seriously distort the projections for DP&L utility because those financial statements become a confusing mix of regulated delivery service and unregulated generation supply. This makes those projections unreliable, confusing, and difficult to interpret.

A second area of concern is that the DP&L regulated utility revenues may be seriously understated for the 2017 to 2023 time period due to some pessimistic modeling assumptions. Mr. Jackson's testimony states that the projections incorporate the results of the pending base rate case, but there appears to be little in the way of assumed revenue growth after 2017. For example, the projections include no DIR revenue, no revenue from transmission service regulated by the Federal Energy Regulatory Commission ("FERC"), and no revenue from the Reconciliation Rider. While the Utility does indicate that it incorporates the potential effects of future base rate cases, the assumed growth in distribution revenue seems very modest.[17]

These seem to be unreasonable modeling assumptions because the projections do include utility cost increase drivers such as substantial new investment, expectations of salary increases, the effects of inflation, etc. If the cost of service increases but the assumed revenues do not increase accordingly, then earnings and cash flow may be substantially understated, showing an exaggerated need for additional revenues.

[17] See the response to OCC INT-304 and 306 Attachment 1.

In addition, Mr. Jackson assumes that DP&L will incur a large increase in its cost of new debt in comparison with current market conditions. He assumes a debt cost rate of 6.60 percent for the new debt that will replace the Utility's $445 million of variable rate debt. This rather pessimistic assumption concerning an above current market cost of debt (for an investment grade utility) also serves to depress the projected cash flow and earnings, unless one also assumes that there will be an offsetting rate increase.

Finally, I must comment on the projections of wholesale generation supply markets sponsored by Witness Crusey. I take no position on the reliability of those projections other than to note that they seem quite different from earlier projections made in this docket (but later withdrawn). These market projections appear to be a major driver of the financial results and the opinions of Mr. Jackson and Mr. Malinak regarding the DMR request. As no one has an accurate and reliable track record in forecasting wholesale energy and capacity market prices over an extended period of time, this introduces a great deal of uncertainty into the projections used to justify the need for the DMR.

For all of these reasons, the PUCO should not rely on the Utility's financial projections as the basis for ordering customers to pay a DMR of $1.015 billion

Q31. YOU MENTION EARNINGS. HAVE YOU EXAMINED THE EXPECTED ROE FOR DP&L WITH THE PROPOSED DMR?

A31. Yes, I have performed that calculation. First, I assume that without the DMR (and with the assumed transfer of the generation assets) DP&L would simply earn its requested 10.5 percent ROE on its book equity (using the Utility's own projection of those common equity balances). Further, I calculate that $145 million per year of DMR revenue provides $94 million of after-tax profit (using witness Mr. Adams's 1.55 revenue expansion factor). Combining these two earnings sources produces a range of ROEs during 2017 to 2023 of roughly 20 to 27 percent. While these ROEs are extraordinarily high, and unquestionably would be considered significantly excessive, I am concerned that they actually may be understated. This is because the Utility projections of the DP&L equity ratios in the later years of the forecast period seem unusually high, higher than would be normal for a regulated utility. These large equity balances tend to depress calculated ROEs.

To supplement these calculations, I have also calculated the ROEs associated with the DMR using data from the pending base distribution rate case. In that rate case, the Utility is requesting approval of a distribution rate base of $684 million, an ROE of 10.5 percent, and an equity ratio of 50 percent. Using this information and the DMR after-tax earnings of $94 million mentioned above produces a calculated ROE of about 38 percent.[18] To be clear, this would be the ROE earned on distribution service when including the DMR. I also recognize that DP&L's rate base is likely to grow over time, and the Utility may decide to move to an even higher equity ratio. Consequently, I calculated a sensitivity case increasing the rate base by 20 percent and increasing the equity ratio from 50 to 60 percent. Keeping the DMR the same, under this sensitivity the ROE on distribution service becomes "only" 33 percent. In a sense, these ROE calculations are more meaningful than my 20 to 27 percent results because they do not rely on the Utility's questionable financial projections and are based purely on distribution service, with no distortion from including in the calculated ROE generation assets and operations. Moreover, they are calculated using the Utility's own public rate case data. These rates of return that I have calculated are far too high to be considered just and reasonable even in the context of SEET.

Q32. MR MALINAK SUGGESTS THAT DP&L'S PROJECTED ROES ARE OVERSTATED IN HIS FINANCIAL PROJECTIONS DUE TO THE GENERATION-RELATED "IMPAIRMENT CHARGE." DOES HE HAVE A VALID POINT?

A32. No, he does not. Mr. Malinak at page 5 sets forth the simple observation that DP&L's projected ROE would be a lower figure than he and Mr. Jackson show if the equity impairment charge of $584 million is reversed, i.e. if we pretend that the equity balance is much higher than it actually is. His observation is a

[18] Calculated as: (($684m x 10.5% x 50%) + $94 m) / (50% x $684 m) = 38%.

mathematical truism because the equity balance is the denominator in the ROE calculation, as we all know. A higher balance mechanically means a lower ROE. But his observation is irrelevant since neither investors, investor analysts, nor credit rating agencies would do what he suggests and add back to equity the $584 million when calculating the ROE. In fact, the asset impairment charge reflects the reduced economic and market value of the generation assets as compared to their previous value. Since DP&L intends to transfer these generation assets to an affiliate, Mr. Malinak's point (even if it had any validity) is moot. Finally, the impairment charge that he discusses has nothing to do with DP&L's regulated delivery service and is irrelevant for that reason. I have addressed what may be Mr. Malinak's concern (i.e., a diminished equity balance) by using in my ROE calculation the PUCO's and the Utility's target 50/50 capital structure.

Q33. MR. JACKSON AT PAGE 23 ARGUES THAT THE DMR SHOULD BE EXEMPT FROM THE SEET. DO YOU AGREE?

A33. Absolutely not. His argument is quite simple: the full amount of the DMR revenues are needed to achieve the DPL, Inc. credit metric targets, regardless of how high this makes the DP&L earned ROE. I do not find this argument to be reasonable for several reasons. As noted earlier, the DMR dollars are likely to flow from DP&L utility to DPL, Inc. in order to support the generation assets and to manage the excessive DPL, Inc. debt, much of which is related to the 2011 merger. The DMR revenues are also an enormous enhancement to the profits of AES Corporation. As I noted, the ROE on regulated distribution service with the

$145 million per year DMR is likely to be in excess of 30 percent, profits that are significantly excessive. If the DMR, as filed, is approved, then the SEET becomes the only real protection that captive distribution customers would have from paying unjust and unreasonable ESP rates. While DP&L is free to propose a higher SEET ROE than the 12 percent approved by the PUCO in the most recent ESP (and later withdrawn by DP&L), some limitation on the profits of DP&L would earn under a DMR regime clearly would be essential for this proposed mechanism to be fair.

I do understand Mr. Jackson's argument that (effectively) the application of the SEET could limit the flow of funds from DP&L to DPL, Inc. But the protection of Utility customers, and not the profits of DPL, Inc. and AES Corporation, should be the regulatory priority. Moreover, there are other means available to protect the DP&L credit ratings, which should be the proper focus of this case.

Q34. WHAT ALTERNATIVES TO PROTECT CREDIT RATINGS SHOULD BE CONSIDERED?

A34. It is my opinion that it is primarily the responsibility of DP&L/DPL, Inc./AES Corporation management to proactively address the credit quality issue set forth in the Utility's ESP filing. Instead, management has set about to address this issue by asking the PUCO to solve it on the backs of Utility customers. This is particularly improper, as well as opportunistic; because the proposed "solution" would severely burden Utility customers, impair the Dayton area economy, all while enhancing the (pre-tax) profits of AES Corporation by more than $1 billion.

Exploiting financial distress in order to enhance corporate profits in this manner is unreasonable and unacceptable because it is unnecessarily burdensome to customers. Further, there is no credit quality crisis for DP&L if the Utility is viewed on a stand-alone basis and if it were to operate as a pure delivery service utility, as intended. Rather, the problem exists primarily because of the generation assets (which should be transferred out of the Utility) and DP&L is being "held hostage" to the excessive leverage of its parent, DPL, Inc. Tangible and constructive steps that should be taken to properly address this problem by management would include the following:

(1) Transfer the generation assets from DP&L, as previously directed and approved by this Commission, to an unregulated affiliate as soon as practicable.

(2) "Ring fence" DP&L from its parent and unregulated affiliates so that it becomes and is viewed as legally separate and "bankruptcy remote." This would mitigate the weak credit ratings of DPL, Inc. from dragging down DP&L, a problem highlighted in Mr. Malinak's testimony.

(3) Once the generation assets are transferred, management should consider and pursue potential asset sales, using the sales proceeds to deleverage DPL, Inc.

(4) DP&L should at least temporarily refrain from making dividend payments to DPL, Inc. until it reaches its target capital structure previously ordered by this Commission, i.e., an equity ratio of at

least 50 percent. In addition, DP&L should not make future dividend payments to DPL, Inc. if doing so pushes its equity ratio below the target 50 percent.

(5) AES Corporation must take responsibility for this problem that it had a hand in creating by making equity contributions to DPL, Inc. A financial distress and credit rating problem should not be exploited as a profit center or opportunity to be seized on.

(6) Additionally, AES Corporation could provide some loan support or guarantee to DPL, Inc. for new borrowings to replace existing low-quality debt. This would be a temporary measure while DPL, Inc. goes through the process of deleveraging.

Q35. PLEASE EXPLAIN FURTHER HOW AGGRESSIVE RING FENCING COULD HELP PROTECT DP&L.

A35. Mr. Malinak has correctly stated that DP&L's credit ratings are to some degree linked to those of DPL, Inc. This is because credit rating agencies are concerned that DP&L could be adversely impacted by a DPL, Inc. debt default or bankruptcy. For this reason, it would help protect captive customers to put in place structures or measures that provide greater credit rating separation for DP&L. This would enable DP&L to be rated on more of a stand-alone basis as it would be perceived as being legally protected from a DPL, Inc. debt default or bankruptcy.

Ring fencing is a complex and specialized topic for discussion and is not the main focus of my testimony. My recommendation is that corporate management should proceed with implementing such measures as a means of protecting the Utility and its customers. Such ring fencing measures have been successfully implemented in Maryland in response to an affiliate risk issue adversely affecting that state's largest utility. It also has been recently implemented in connection with the Exelon/PHI Holdings merger that closed earlier this year. My Schedule MIK-1 provides a brief outline of the steps that could be taken to achieve an effective ring fencing of the Utility from its parent or corporate affiliate.

Q36. IS IT FEASIBLE FOR AES CORPORATION TO PROVIDE FINANCIAL SUPPORT FOR DPL, INC. TO SUPPORT ITS CREDIT RATING AND ASSIST WITH DELEVERAGING?

A36. Yes, to a significant degree. While AES Corporation also is overleveraged and faces financial constraints, it can provide cash flow and equity assistance to DPL, Inc. if it chooses to do so as a business priority. My Schedule MIK-2 includes a presentation by management at a recent investor conference (June 22, 2016) in which AES Corporation projects free cash flow of over $1 billion per year and growing by more than ten percent per year. (See page 19 from that presentation.) In addition, AES Corporation is paying out to its shareholders cash dividends of more than $300 million per year. The Value Line Investment Survey (September 23, 2016) projects the AES Corporation per share dividend to increase over the next several years by 11 percent per year. In addition, AES Corporation has the ability to issue new equity to raise more cash and strengthen its own balance sheet. AES Corporation clearly has considerable discretion concerning how to deploy its cash and whether to assist its subsidiaries. Those opportunities should be looked to before requiring captive customers to provide a bail out.

IV. UNDER THE ESP VERSUS MRO TEST, THE ESP IS NOT MORE FAVORABLE IN THE AGGREGATE TO CUSTOMERS THAN AN MRO

A. The Statutory Test

Q37. WHAT IS YOUR UNDERSTANDING OF THE REQUIREMENT FOR PUCO APPROVAL OF AN ESP?

A37. As acknowledged by DP&L in the Application, EDUs may satisfy the requirement to provide a standard service offer either through an electric security plan or a market rate offer.[19] The requirements for a market rate offer include a competitive bid process that adheres to certain standards, procedures, and criteria specified in Ohio Revised Code, Section 4928.142. A market rate offer addresses the price for generation, nothing more, nothing less. The requirements and potential features of an ESP are specified in Ohio Revised Code, Section 4928.143. R.C. 4928.143 addresses the establishment of SSO generation rates and identifies provisions that are permissible, including "distribution infrastructure and modernization." There are no similar provisions that can be

[19] R.C. 4928.141(A).

included as part of a market rate offer. The ESP statute also provides the test for PUCO approval of an ESP. If a utility proposes an ESP, the PUCO: shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. (Ohio Revised Code, Section 4928.143 (C) (1).)

The statute further states that a utility has the burden of proof under this provision.

B. DP&L's Application of the Test is flawed and overstates the value of the ESP

Q38. PLEASE DESCRIBE HOW DP&L HAS APPLIED THIS TEST.

A38. Utility witness Malinak addressed the ESP versus MRO statutory test on pages 56 - 65 of his direct testimony. Mr. Malinak begins by asserting that the test has three components: (a) the quantified rate impacts, referred to as the Aggregate Price Test, (b) other quantifiable impacts, and (c) qualitative attributes. Recognizing that the DMR is the center piece of the ESP, he defines two scenarios for assessing that rider. The first is that essentially the same DMR would be approved under an MRO, and the second is that the DMR would not be approved under an MRO.

For all practical purposes, the first scenario merely eliminates the quantitative part of the statutory test. Moreover, Mr. Malinak never really explains why this scenario would be a realistic or feasible outcome. For example, he identifies no regulatory mechanism under an MRO for approving a DMR or why such an outcome is likely. My assessment is that there is no provision under the MRO statute that would permit a distribution modernization rider to be approved. Mr. Malinak appears to agree because his testimony does not argue that this scenario is in fact a likely outcome.

Under the second scenario, he does concede that the ESP creates a $1 billion quantifiable cost to consumers. However, his analysis does omit the $20 million cost of the Reconciliation Charge suggesting that cost also would be incurred (somehow) under an MRO (with no explanation). Finally, Mr. Malinak correctly observes that the SSO rates would be identical under the MRO and ESP because the exact same CBP would be used.[20] In other words, DP&L would employ the same auction process and SSO arrangements under both the as-filed ESP and an MRO. Witness Malinak also claims no quantified rate impact (positive or negative) from the various other riders proposed in the ESP. He assumes that

[20] Malinak testimony, page 60.

these charges would be the same under the as-filed ESP and an MRO, although he does not explain why he believes this is true.[21]

Q39. DOES WITNESS MALINAK PROVIDE ANY OTHER QUANTIFICATION?

A39. No, he does not identify any other non-rate quantifications or even impacts that could be quantified.

Q40. DOES WITNESS MALINAK ADDRESS THE QUALITATIVE ATTRIBUTES OF THE ESP?

A40. Yes, he does so briefly on pages 62 and 63 of his testimony. These purported benefits include avoidance of DPL, Inc. financial stress and the DP&L credit ratings problem accomplished through the implementation of the DMR. He argues that this will help ensure "safe and stable" service for DP&L distribution customers. He then goes on to opine that the benefits of having a credit worthy and financially sound DP&L would exceed the $1 billion customer cost of the DMR.

Witness Malinak then goes on to list four other qualitative benefits of the ESP: (1) the inclusion of a SEET, (2) the inclusion of a Clean Energy Rider, (3) the DIR, which can facilitate needed distribution investments, and (4) the notion that rejection of the instant ESP somehow would preclude future (and presumably beneficial) ESPs.

[21] Id., page 61.

C. Critique of DP&L's Application of the Test

Q41. HOW HAVE YOU APPROACHED THE ESP VERSUS MRO TEST?

A41. I believe that the application of the test in this case must focus primarily on the DMR and Mr. Malinak's two DMR scenarios. His first scenario (i.e., the same DMR would exist under either an MRO or ESP) should be given no weight in a proper application of the test. In addition to being completely speculative, it effectively makes the statutory test a meaningless and empty exercise by defining away the entire quantitative component of the test. It also does not make much sense. If the PUCO were to reject the DMR and the ESP here, it is not clear why it would be inclined to approve it as part of an MRO. And the language in the MRO statute does not provide any room for a DMR. The MRO deals solely with the price of the SSO -- it is generation related only.

With regard to the second DMR scenario, it appears that Mr. Malinak and I are largely (but not entirely) in agreement. That is, we agree that the ESP will increase customer rates by more than $1 billion as compared to an MRO.

Q42. WHAT ARE YOU CONCLUSIONS CONCERNING THE ESP VERSUS MRO TEST?

A42. I find that the as-filed ESP likely will be harmful to customers relative to an MRO, and this is mostly due to the DMR proposal. My review of other proposed riders (DIR, Reconciliation Rider, and Clean Energy Rider) reinforces my conclusion that the as-filed ESP does not pass the statutory test of benefits in the aggregate.

Q43. WHAT IS YOUR FINDING CONCERNING THE AGGREGATE PRICE TEST?

A43. I have determined that there are two components to the Aggregate Price Test for the DP&L ESP, with both being adverse for customers. The cost of the DMR is $1.015 billion. In addition, the Utility's response to OCC INT-302 indicates that the balance (inclusive of interest) of the over-market OVEC costs at September 30, 2016 is about $18.8 million. I assume that by year end 2016 the balance would be about $20 million. Thus, the total net detriment for utility customers would be about $1.035 billion.

Q44. WHY DO YOU DISAGREE WITH WITNESS MALINAK'S QUALITATIVE ANALYSIS?

A44. While his discussion of qualitative attributes is relatively brief and superficial, I find that it is useful to place his arguments into two categories: (a) attributes associated with the DMR, and (b) other ESP qualitative arguments. With regard to the DMR, he argues that the DMR is required to ensure that DP&L can continue to provide safe and reliable service, make needed investments, and facilitate beneficial grid modernization. The key notion is that the DMR is essential to protecting the DP&L investment grade credit ratings.

While I concur that the protection of DP&L's investment grade credit ratings is vitally important, the $1 billion DMR, as proposed, is not required for that purpose. DP&L can be protected and strengthened by taking the management actions outlined in my testimony that ultimately are the responsibility of corporate management – not customers. But the essential point is that the costs of such solutions would be far less than the bloated and onerous $1 billion cost of the DMR. In essence, Mr. Malinak's qualitative benefit claim is based on a false choice – a $1 billion charge to customers versus substandard distribution service. At the end of the day, the $1 billion charge is not necessary and is all about enhancing corporate profits, not reliable distribution service.

Mr. Malinak's grid modernization argument is similarly illusory. As noted above, the $1 billion charge is not needed to place DP&L on sound footing from a credit rating point of view since this can be done at much lower cost to customers. This means that the overly burdensome DMR is not needed to pursue grid modernization. Perhaps more telling there is no grid modernization plan or proposal in this case. Under DP&L's DMR proposal there is no commitment that that the grid would be modernized. Consequently, Mr. Malinak attempts to assert qualitative benefits for a grid modernization plan that simply does not exist, let alone been proposed. Moreover, contrary to his testimony, there is nothing that would prevent the Utility from seeking to collect costs for grid modernization investments in a distribution base rate case or in FERC-approved transmission rates.

Q45. IS THERE ANY MERIT TO HIS CLAIMED QUALITATIVE BENEFITS FOR THE NON-DMR FEATURES OF THE DP&L ESP?

A45. No. As I noted, there are four such asserted qualitative benefits. First, he claims that absent the ESP, customers lose the protection of the SEET. This argument overlooks the key fact that Witness Jackson proposes that the DMR – which represents the vast majority of ESP costs – would be exempt from the SEET. As I have shown, this exemption could produce distribution service ROEs in excess of 30 percent, with the SEET providing customers with no relief from such high profits. Thus, the inclusion of the SEET in the ESP provides no meaningful protection for customers at all. Mr. Malinak also fails to acknowledge that there are SEET protections that apply to a market rate offer. So any qualitative benefits on the ESP side are matched on the MRO side, creating a wash.

Second, he touts the Clean Energy Rider as a qualitative customer benefit even though no specific project has been defined, identified, or proposed. Moreover, based on my reading of Utility testimony, this rider will force customers to subsidize the DPL, Inc. unregulated coal plants. This rider not only is ill-defined but improper in its concept and scope. Mr. Malinak's only argument in support of this rider is the tautology that the Commission would not approve this rider unless it found it to be beneficial. By that logic, no utility proposed rider could ever be found not to be beneficial and thus no qualitative review is even needed. This is simply another circular argument by Mr. Malinak to render the statutory test irrelevant.[22]

The third qualitative argument is that the DIR must be beneficial or the Commission would not approve it – the same empty duplicative reasoning as he applied to the Clean Energy Rider. His testimony does not address the actual attributes of the rider. Because the DIR is critiqued extensively by OCC Witnesses Effron and Williams, I rely on their assessments that it is improper and does not on balance provide qualitative benefits for customers.[23]

Mr. Malinak's fourth argument is that if the ESP is rejected, DP&L is somehow forever precluded from proposing another ESP, thereby denying customers the benefits of that future ESP. Unfortunately, he does not explain what future benefits would be foregone or denied. Consequently, it is impossible to give any credence to this argument.

In summary, I do not find any of Mr. Malinak's qualitative arguments to be either substantive or persuasive. These asserted qualitative benefits for customers certainly cannot begin to offset in any meaningful way any quantitative cost of the ESP, let alone the more than $1 billion cost of this ESP.

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[22] Please see Section IV.E. for a more detailed discussion of the merits of this rider and why it is improper.

[23] Also, please see my more detailed discussion in Section IV.E.

D. The Reconciliation Rider allows DP&L to collect transition costs

Q46. WHAT IS DP&L'S PROPOSAL CONCERNING THE RECONCILIATION RIDER?

A46. This Rider and the current proposal are described in the testimony of DP&L witness Parke.[24] DP&L in this ESP proposes to use the Reconciliation Rider to collect certain past costs associated with the Utility's OVEC entitlement. Specifically, these are the OVEC "above market" costs that DP&L incurred but did not fully collect from the PJM wholesale markets. As I previously noted, the reconciliation balance is likely to be at least $20 million by year-end 2016, much larger than the $10.5 million stated in the Amended Application.

Witness Parke justifies this charge and the proposed deferral accounting treatment by referencing the Commission's Order in Case No. 13-2420-EL-UNC (the divestiture docket), which he claims "required DP&L to sell its OVEC generation into PJM's day-ahead markets."[25] He offers no other justification for the deferral and collecting above-market generation costs from distribution customers.

[24] Direct Testimony of Nathan C. Parke, at 7-8.

[25] Id., at 7.

Q47. DOES THE COMMISSION'S ORDER IN CASE NO. 13-240-EL-UNC SUPPORT THE REQUEST FOR DEFERRAL AND COST COLLECTION OF OVEC ABOVE MARKET COSTS?

A47. No. That Order approves the Utility's proposed plan for the divestiture of its generating assets to an affiliate. In doing so, the Commission addressed several disputed issues including the Utility' request to retain for some period of time its OVEC entitlement.

The Order does permit DP&L to retain the OVEC entitlement for a period of time until DP&L is able to divest it, subject to certain conditions. Specifically, DP&L must make good faith efforts to divest its OVEC entitlement, and it must sell its OVEC generation supply into the regional wholesale market.[26] Setting up a Reconciliation Rider would hinder the divestiture of the OVEC assets because allowing full recovery of the costs associated with the assets does not incentivize DP&L to divest. Instead, it incentivizes it to retain the OVEC assets.

Notably, the Order did not authorize DP&L to create a deferral for any unrecovered OVEC costs that it incurs and to collect such deferred costs from Utility customers. DP&L made just such a request in that docket.[27] Moreover, I note that the Order did not authorize a deferral for OVEC even though the Order

[26] Finding and Order, at 15-16.

[27] Id, at 14.

does authorize deferral treatment for other DP&L costs.[28] Consequently, there is nothing in the Commission's Order that would support the Utility's proposal in this case.

Q48. ARE THERE ANY OTHER REASONS FOR DENYING THE OVEC RECONCILIATION RIDER?

A48. Yes. The Commission's conditional authorization, which allows DP&L to retain for a period of time the OVEC entitlement, appears to be intended as a temporary accommodation for the Utility until it can be divested. This in no way implies that Utility distribution customers should be responsible for OVEC over-market costs. Again, such charges to customers to recover above market costs would be a transition charge. And the PUCO cannot authorize any more transition charges for DP&L.[29]

I further note that the Commission's Order in the divestiture case authorized continued use of the Service Stability Rider ("SSR") to support the Utility's financial integrity.[30] Therefore, DP&L has been collecting funds from customers (approximately $293.3 million) under the SSR to provide financial support during the time period that DP&L now requests the OVEC deferral, at least through September 2016. It clearly would be excessive and unreasonable for DP&L to

[28] Id, at 13.

[29] DP&L was authorized to collect $1.9 billion in transition charges from customers since 2000.

[30] Id., at 10.

have collected both the SSR charges and, now, the deferred OVEC above market costs.

E. The Clean Energy Rider would require customers to subsidize the power plants that are owned by DP&L's affiliate.

Q49. WHAT IS THE PROPOSAL FOR A CLEAN ENERGY RIDER?

A49. The proposed Clean Energy Rider ("CER") is described by Utility witness Claire E. Hale, although this witness does not provide any quantification estimates of the charges from this rider to consumers. Nor are any specific "clean energy" project expenses or investments mentioned. Included in the scope of cost collection from Utility customers under the proposed CER are "environmental compliance costs, environmental expenses, and decommission costs."[31] While specific costs and investments that would qualify for the CER are not described, it would appear that it would apply primarily to the coal plant environmental compliance costs not known today. At page 5, witness Hale states:

> To that end, the Company expects it will incur environmental costs as a result of its current ownership of generation assets. It also expects that, consistent with state and federal policies, new renewable requirements will be imposed by future regulations.

[31] Direct Testimony of Claire E. Hale, at 5.

The Hale testimony goes on to cite various new environmental regulations expected to impact coal plants. This would include the Cross State Air Pollution Rule, which could implicate air emissions, and the potential requirement to close ash ponds.

Q50. WHY DOES WITNESS HALE BELIEVE IT IS APPROPRIATE TO CHARGE CUSTOMERS FOR THE CLEAN ENERGY COSTS OF COAL PLANTS?

A50. Witness Hale argues that DP&L distribution customers should pay for the future coal plant environmental compliance costs because customers benefitted from the power supply from those plants in past years prior to the introduction of deregulation.[32]

Q51. HAS THE COMMISSION ADDRESSED CHARGING CUSTOMERS FOR THE CLEAN ENERGY COST OF COAL PLANTS?

A51. Yes, the Commission did so in its Order in the 2014 divestiture docket, Case No. 13-2420-EL-UNC. In that case, DP&L requested as part of its divestiture plan that the Utility retain responsibility for future environmental liabilities associated with the legacy coal plants. The Commission rejected this request:

Therefore, we direct DP&L to include provisions in any contract or other agreement to divest the generation assets which transfer all environmental

[32] Id., at 7-8.

liabilities with the assets and which fully insulate ratepayers from any potential recovery of the costs of any such environmental liabilities.

It seems clear that the PUCO intended that post-divestiture Utility distribution customers not be responsible for the environmental compliance costs of the coal plants. The proposed CER is not consistent with that PUCO intention.

Q52. IS THE COAL PLANT COMPLIANCE COST ASPECT OF PROPOSED CER APPROPRIATE?

A52. No, it is not. It is expected that the legacy coal plants will be owned by an unregulated affiliate of the Utility during the term of the ESP, not by DP&L itself. Utility customers will not be receiving service from the legacy coal plants going forward, and therefore should not be responsible for the costs of future environmental compliance costs. In fact, I believe that it is fair to describe this aspect of the proposed CER as a transition charge because its purpose is to financially support the deregulated, legacy coal plants.

Q53. THE PROPOSED CER WILL ALSO BE USED TO COLLECT THE COST OF RENEWABLE RESOURCES FROM CUSTOMERS. IS THIS ASPECT OF THE PROPOSED CER REASONABLE?

A53. There is simply not enough information from the Application and testimony to reach any conclusion on this aspect of the proposed CER. No specific renewable energy projects or costs that would be eligible for CER treatment are identified or quantified. It is not clear whether this is intended to be future renewable projects that would be owned by DP&L itself on a regulated basis or by an unregulated corporate affiliate of DP&L. It certainly would not be appropriate to charge DP&L's captive distribution customers for the corporate affiliate's renewable energy projects. Whether DP&L should in the future acquire renewable generation resources is certainly an important policy issue for the PUCO that should not be addressed in this docket.

Hence, the renewable energy aspect of the proposed CER is at best premature. It is inappropriate to create a cost recovery mechanism for utility renewable resource costs absent any detailed proposal for actually acquiring such resources or addressing the key threshold policy issues.

Q54. HAVE RENEWABLE RESOURCE COSTS AND COST RECOVERY BEEN ADDRESSED ELSEWHERE IN THE ESP APPLICATION?

A54. Yes, it is discussed in the testimony of DP&L witness Eric R. Brown at pages 4-7. His testimony describes the plan for the SSO supply and its cost recovery. As his testimony indicates the selected CBP wholesale supplies must include renewable Energy Credits ("REC") as part of the full requirements contract products that will be supplied to SSO customers. Those customers obviously will pay the cost of those RECs in the Commission-approved SSO rates as determined in the CBP. Consequently, a cost recovery mechanism for renewable resources is already included in DP&L's proposal in this case. Moreover, this renewable energy feature and cost recovery from customers would be present under both the proposed ESP and an alternative MRO. The renewable energy aspect of the CER is not needed at this time since there is no renewable energy proposal beyond what is described in witness Brown's testimony. The proposed CER is not needed, is improper, and should be denied.

F. The Proposed DIR Should Be Rejected

Q55. WHAT IS DP&L'S PROPOSAL CONCERNING THE DIR?

A55. The DIR is described at pages 2-4 in the direct testimony of Utility witness Adams. As his testimony indicates, the DIR will be calculated and the resulting rate change implemented twice per year. It will reflect the capital cost carrying charges (i.e., return on and of investment and related property and income taxes) for incremental used and useful distribution investment. It also will include certain incremental O&M expense items. However, it will not include the costs of general plant and office buildings. He describes this mechanism as a "true up." Notably, witness Adams testimony provides a sample calculation of the DIR as an illustration, but he does not provide projections or estimates of either the DIR costs over time or the rate impacts on customers. In addition, no rate caps or limitations on rate increases have been included in the proposal.

The proposed DIR is critiqued by OCC witnesses Williams and Effron. Mr. Williams provides several reasons why this proposal should not be accepted, including the fact that it does not appear to qualify as being infrastructure "modernization," the potential for the double recovery of costs, and that it is not justified by the need to improve service quality. He also expresses concerns over the adverse rate impacts and affordability for customers. OCC Witness Effron also critiques the DIR and witness Adams's calculations. He suggests certain modifications in the event the PUCO does decide to proceed with accepting the DIR.

G. The ESP should be limited to three years, instead of the seven years proposed by DP&L

Q56. WHY DOES DP&L PROPOSE A SEVEN-YEAR ESP?

A56. This time period is being proposed to accommodate the collection of $1.015 billion for the benefit of primarily DPL, Inc. under the DMR. I note that Commission-approved ESPs typically have been for shorter time periods, such as three years. In this case, the driver of the ESP time period appears to be the proposed DMR, which would continue to charge customers $145 million per year in every year of the seven-year ESP. This charge is based on a series of financial projections that are suspect or at best, highly uncertain.

Q57. DO YOU BELIEVE A SEVEN-YEAR TERM OF THE ESP IS APPROPRIATE?

A57. No. In addition to DMR, DP&L in this case is proposing several new (or substantially revised) rate riders that could have substantial but unknown impacts on customers. This includes the Reconciliation Rider, the DIR, the CER, and cost recovery associated with the CBP for SSO customers. The DIR is particularly important as it is new and could involve tens of millions of dollars of Utility collections from customers over a seven-year ESP.

My testimony opposes the proposed ESP and its new or revised riders. Other OCC witnesses also oppose some of the proposed riders, the DIR in particular. However, if the PUCO chooses to accept the ESP, either as filed or with modifications, I recommend the PUCO limit the life to three years.

Q58. WHY DO YOU FIND THREE YEARS TO BE MORE APPROPRIATE?

A58. Setting aside the DMR, DP&L in this case is proposing rate mechanisms that are both novel (for DP&L) and far reaching in terms of customer impacts. Moreover, the details of these new riders are not spelled out in the filing in terms of customer and financial impacts. I am concerned that approval of a seven-year ESP would put these new programs and rate mechanisms on "automatic pilot" for nearly a decade. That is simply too long for any rider, particularly for the new and undefined mechanisms proposed by the Utility. I believe it is more appropriate for DP&L to make a new filing after three years to justify the need or continuing need for and customer benefits from these rate riders. Doing so would provide more effective and timely regulatory oversight and protection of customers than an open ended seven-year approval.

Q59. UNDER A SEVEN-YEAR ESP WILL THE RIDERS BE SUBJECT TO AN AUDIT REVIEW?

A59. This is my understanding, although it is not clear in the case of the DMR. For example, the proposed DIR is to be updated twice per year. An audit review can address accuracy of the rate calculations, reasonableness of costs included, compliance with the DIR tariff, and the like.

But audits are not a substitute for a careful and formal policy review. This is needed to determine whether continuation of the DIR and/or the other riders is appropriate and needed and/or whether changes to the structure of the DIR and other riders are needed. After all, over a period of seven years, there can be important changes in circumstances that could warrant termination of or changes to the rider.

I note that the OCC is not opposing any aspect of the proposed CBP for SSO service. Despite this non-opposition at this time, it remains worthwhile to periodically review the structure and features of that program to ensure that it remains appropriate given potentially changing market conditions or determine whether it could be improved. This is DP&L's first foray into procuring 100% of its SSO supply through a CBP and a periodic review should take place. A three-year term for the ESP would ensure that such reviews take place at appropriate intervals and that there are timely opportunities to make improvements.

V. SUMMARY AND CONCLUSIONS

Q60. PLEASE SUMMARIZE THE SALIENT DIFFERENCES BETWEEN YOUR ESP VERSUS MRO TEST AND THAT OF UTILITY WITNESS MALINAK.

A60. Witness Malinak's application of the test is primarily focused on the DMR, as is my application of that test. His first of two DMR scenarios simply assume away the issue and therefore is meaningless. His second scenario at least acknowledges that adverse customer rate impacts would occur under the ESP as compared to an MRO, and we both agree that the cost difference would be in excess of $1 billion. The one difference is that I have included the $20 million cost for the Reconciliation Rider whereas Mr. Malinak seems willing to assume that the same cost would be present under an MRO.

Consequently, the main difference between our respective applications of the test is whether the ESP has positive qualitative attributes and whether those positive attributes are so large as to fully offset the massive and onerous $1 billion cost. Mr. Malinak's main qualitative argument is that the DMR is essential to DP&L maintaining an investment grade credit rating and thereby being able to undertake necessary investments to provide safe and reliable distribution service. He also maintains that the DMR would facilitate beneficial grid modernization. These arguments are unpersuasive. They are based on the misleading premise that there are no less costly means of protecting the DP&L investment grade ratings than throwing vast amounts of customer money at the Utility, for the ultimate benefit of AES Corporation shareholders. My testimony argues that this vital task is primarily management's responsibility and there are measures far less costly to customers that can accomplish this goal. On the basis of fairness, this is not a burden that should be borne by customers, as those customers have had nothing to do with the DPL, Inc. credit rating problems.

Nor is the DMR needed for grid modernization (Mr. Malinak's other alleged qualitative benefit of the ESP). In fact, the Utility has not set forth in this case a grid modernization plan or proposal, and therefore there can be no basis for identifying this as a qualitative benefit of the ESP. In fact, there is no commitment for any DMR dollars to go toward grid modernization.

As noted in my testimony, Mr. Malinak briefly and superficially makes several other qualitative arguments, but none of these are substantive or persuasive, let alone offsetting more than $1 billion in costs that captive utility customers are being asked to shoulder.

Q61. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A61. As summarized above, it is clear that the ESP cannot pass the test and therefore should be rejected and replaced by an MRO. That MRO should incorporate the

CBP for SSO supply described in the Application. This failure of the ESP versus MRO test is primarily due to the onerous cost of the DMR (the DMR also is highly unfair to the Utility's customers). Importantly, if the DMR in some from is adopted, it should not be exempted from the annual SEET review for the reasons described in my testimony.

If the ESP is approved, I recommend the following modifications as supported by me and other OCC witnesses:

- Reject the DMR.
- Limit the ESP to three years.
- Reject the DIR per OCC witness Williams or in the alternative if the DIR is accepted, adopt witness Effron's suggested modifications.
- Reject the proposed Reconciliation Rider and the deferral accounting treatment of historic above-market OVEC costs.
- Reject the proposed CER as ill defined, redundant, and providing an improper subsidy to the legacy, unregulated coal plants.

Q62. DO YOU CONSIDER ANY ASPECTS OF THE ESP TO CONSTITUTE A TRANSITION CHARGE?

A62. Yes. I consider DMR to constitute both affiliate abuse (as its purpose is to subsidize with customer funds the credit quality and profits of its parent and ultimate parent) and a transition charge as its purpose is to provide cash flow and earnings support for deregulated, legacy coal plants that will soon be divested. In addition, aspects of the Reconciliation Charge and CER also are transition charges for the same reason.

Q63. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A63. Yes. However, I reserve the right to update as outstanding discovery information or new information becomes available.

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Direct Testimony of Matthew I. Kahal on Behalf of the Office of the Ohio Consumers' Counsel* was served via electronic transmission to the persons listed below this 21st day of November 2016.

/s/ *William J. Michael*
William J. Michael
Assistant Consumers' Counsel

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DAYTON POWER AND LIGHT COMPANY

Outline of Illustrative Ring-Fencing Plan

The purpose of this schedule is to provide a summary outline illustrating the "ring-fencing" measures that could be taken to protect the credit ratings of a utility from the business and other risks associated with its parent company or other corporate affiliate. This assumes that the utility is already corporate subsidiary of a holding company that issues its own debt and financial statements, as opposed to being a division or department of a larger company. Hence, the ring fencing issues would apply to the arrangements between DP&L and DPL, Inc. This outline follows the plan developed and presented by Mr. Charles Atkins, an Executive Director at Morgan Stanley, for Baltimore Gas and Electric Company ("BGE"), a subsidiary at that time of Constellation Energy.[1] Constellation at that time was a financially distressed company threatening the credit ratings of its utility subsidiary. Mr. Atkins ring-fencing plan for BGE was largely adopted by the Maryland Public Service Commission.

Mr. Atkins has identified three types of risks associated with a utility being owned by a financially distressed holding company parent that could be adverse to customers and utility regulators: (a) the distressed parent (which controls the utility) extracts cash flow or other assets from the utility to address its needs thereby disrupting utility operations; (b) a parent in bankruptcy could require the utility subsidiary to participate voluntarily in that bankruptcy process; and (c) a court could order the utility to be included in the parent's bankruptcy. The mere risk that any one of these events could occur can impair the utility's credit ratings and cause it to be linked to the parent's ratings.

In the case of BGE, Mr. Atkins recommended a series of 12 measures or structures to insulate the utility from the risks of its parent, as follows:

---

[1] *In the Matter of the Current and Future Financial Condition of Baltimore Gas and Electric Company,* the Rebuttal Testimony of Charles N. Atkins II, September 9, 2009, MD PSC Case No. 9173, Phase II.

1. Create a bankruptcy remote holding company special purpose entity ("Holdco SPE") that would be owned by the parent company and hold all of the equity in the utility. The Holdco SPE would have no employees or operations, and its sole function would be to serve as the owner of the utility.

2. The Holdco SPE would have at least one independent director, and any bankruptcy filing for the Holdco SPE would require the unanimous consent of its directors.

3. As a further protection from affiliate bankruptcy, the Holdco SPE would issue a non-economic interest (referred to as a "golden share") to an SPE administrative company. Under the agreement for that golden share, the Holdco SPE could not voluntarily file for bankruptcy without the consent of the SPE administrator.

4. The transfer of the utility shares from the parent to the Holdco SPE would be documented as "an absolute conveyance" in order to ensure that the utility does not become part of the parent's bankruptcy estate (in the event of such a bankruptcy).

5. The Holdco SPE would establish a series of covenants or requirements in order to enhance its separation from the parent and the utility. For example, one covenant would be that the Holdco SPE could not comingle its funds with either the parent or the utility.

6. Similarly, the utility would take steps to ensure its separation from both the Holdco and the parent. The utility would maintain an arms-length business relationship with both entities.

7. In implementing the above steps and the various separation covenants and practices, the utility and parent would procure outside legal counsel to provide a legal opinion, based on established legal precedent, that neither the utility nor the Holdco SPE would be consolidated into parent bankruptcy (or for the utility consolidated into a Holdco SPE bankruptcy).

8. The utility shall maintain detailed documentation and annual reporting to its regulator that it and the Holdco SPE have achieved compliance with all of the measures structural changes and covenants outlined in steps (1) – (7). This documentation and reporting will help to satisfy rating agency concerns that the legal separation (for bankruptcy purposes) has been carefully maintained and legal requirements satisfied.

9. An officer of the parent company must certify that the parent company complies with the ring-fencing plan and requirements and that the various required separations have been maintained.

10. The utility's charter or by-laws should be amended to require unanimous consent of the Board of Directors for the utility to voluntarily file a bankruptcy petition.

11. The utility shall agree to restrict its dividend payments to its parent in the event its credit ratings fall below investment grade, or if such dividend payment would cause that equity ratio to fall below some lower end threshold (e.g., 40 percent).

12. The utility's regulatory commission shall issue an order that explicitly approves the ring-fencing plan and requires that the utility adhere to that plan.

The above listed 12 steps are provided here only as a bare bones outline of a ring-fencing plan, with Mr. Atkins's BGE testimony presenting far more detail on the specific measures and procedures that would be required. Importantly, such a ring-fencing plan, while requiring strict separation features and measures, is not intended to materially alter the manner in which the utility operates on a day-to-day basis, its strategic planning, its capital spending plan or its normal financing plan. Rather, the purpose is to convey to the rating agencies, investors and (possibly) the courts that a legal separation and insulation between the utility and its parent has been implemented. Doing so will permit a separation of credit ratings between the utility and the parent.

Schedule MIK-2

The AES Corporation
Tom O'Flynn, EVP & CFO

JP Morgan Energy Equity Conference
June 27, 2016

AES
we are the energy

Safe Harbor Disclosure

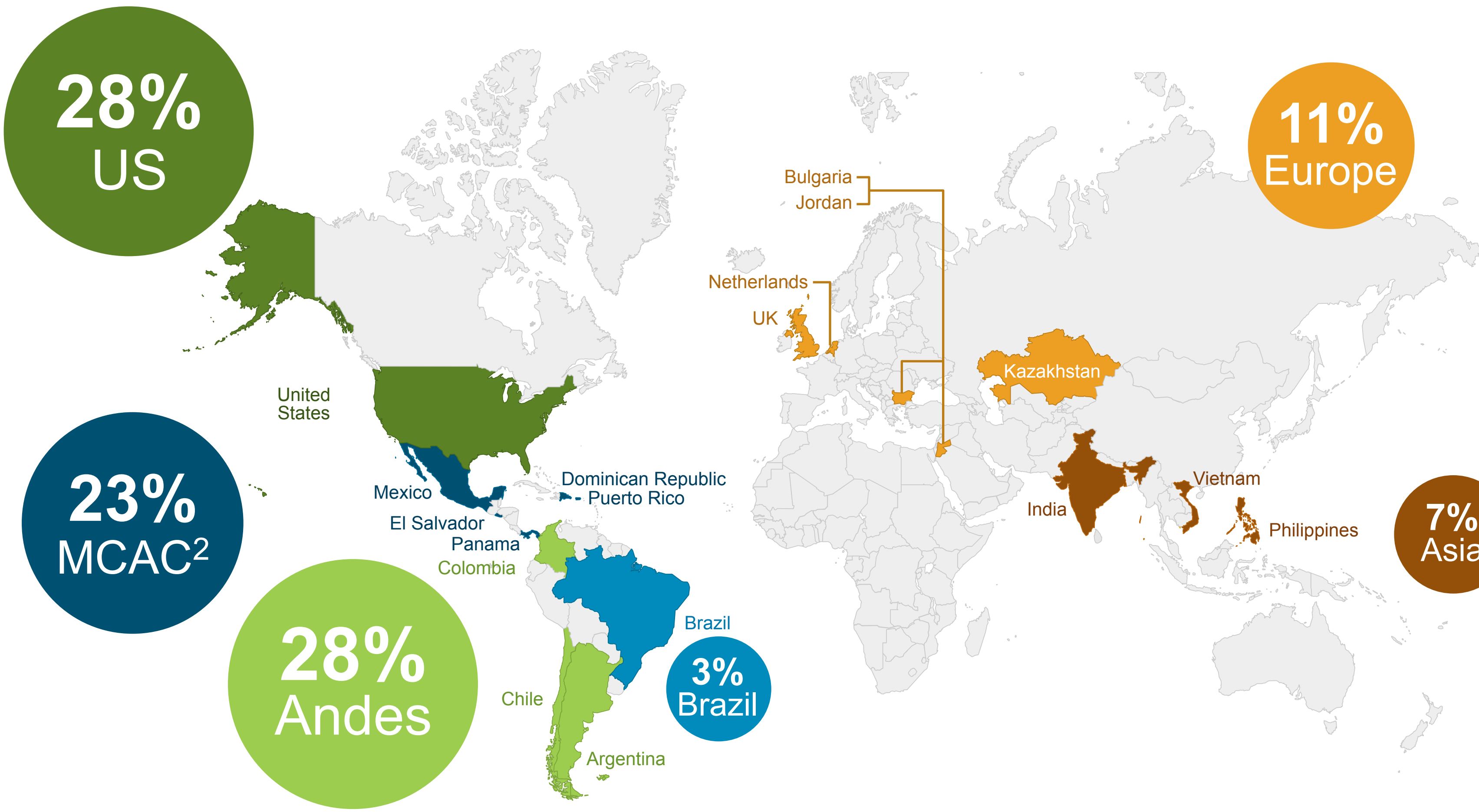
Certain statements in the following presentation regarding AES' business operations may constitute "forward-looking statements." Such forward-looking statements include, but are not limited to, those related to future earnings growth and financial and operating performance. Forward-looking statements are not intended to be a guarantee of future results, but instead constitute AES' current expectations based on reasonable assumptions. Forecasted financial information is based on certain material assumptions. These assumptions include, but are not limited to, accurate projections of future interest rates, commodity prices and foreign currency pricing, continued normal or better levels of operating performance and electricity demand at our distribution companies and operational performance at our generation businesses consistent with historical levels, as well as achievements of planned productivity improvements and incremental growth from investments at investment levels and rates of return consistent with prior experience. For additional assumptions see Slide 32 and the Appendix to this presentation. Actual results could differ materially from those projected in our forward-looking statements due to risks, uncertainties and other factors. Important factors that could affect actual results are discussed in AES' filings with the Securities and Exchange Commission including but not limited to the risks discussed under Item 1A "Risk Factors" and Item 7: "Management's Discussion & Analysis" in AES' 2015 Annual Report on Form 10-K, as well as our other SEC filings. AES undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Overview

- Capitalizing on our advantaged position in key high growth markets
- Reshaping our business mix by adding projects with long-term, U.S. Dollar-denominated contracts
- Strengthening our Balance Sheet by paying down debt
- Expecting double-digit growth in free cash flow and earnings

Business Managed in Six Strategic Business Units (SBUs)

% = 2016 Expected Adjusted Pre-Tax Contribution (PTC)[1]



1. A non-GAAP financial measure. See Appendix for definition and reconciliation. 2016 Adjusted PTC of $1.5 billion before Corporate charges of $0.4 billion.
2. Mexico, Central America and the Caribbean.

Regulatory Developments in Ohio – Dayton Power & Light (DP&L)

- DP&L filed its new Electric Security Plan (ESP) in February 2016, to be effective in 2017 – in discussions with the utility commission staff
- On June 20, 2016, the Supreme Court of Ohio reversed the utility commission's prior approval of DP&L's current ESP (2014-2016)
  - ESP allowed DP&L to collect a non-bypassable Service Stability Rider (SSR) of ~ $9.2 million per month
  - Ruling was brief, so impact is unclear at this point
- Under the rules of the Supreme Court of Ohio, the court will issue a mandate with respect to its ruling by June 30, 2016
  - The mandate may provide clarity on DP&L's potential options in response to the ruling
  - If no options available, loss of DP&L's SSR is expected to be material
- AES has not received dividends from DP&L since 2012 and did not plan to receive any dividends in our future expectations, so there is no impact on expected Parent Free Cash Flow[1]

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

Disciplined Growth

Pursuing Disciplined Growth Projects

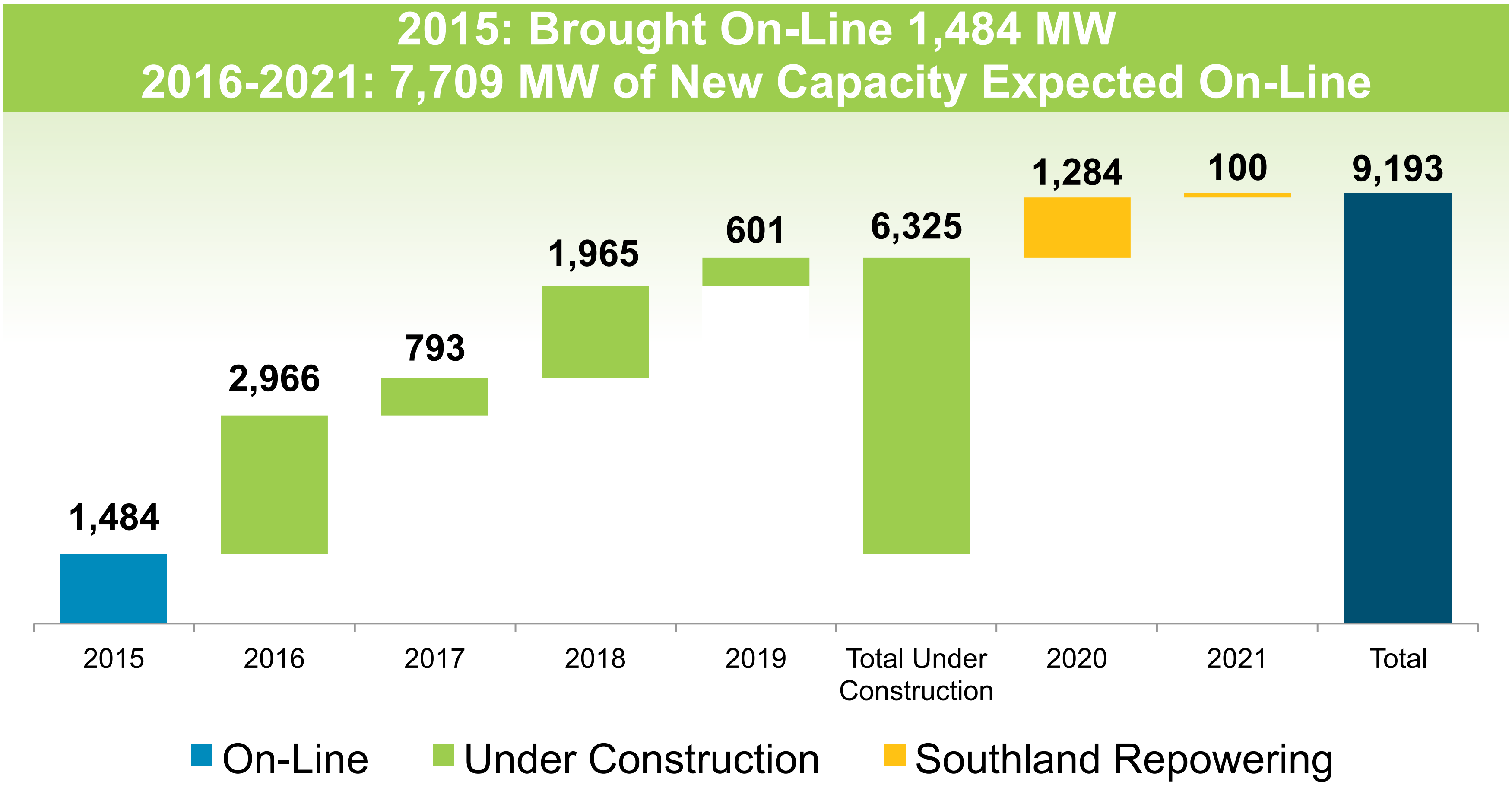
Leveraging our advantaged platforms

Focused on projects with:

- Long-term contracts
- U.S. Dollar-denominated revenues

Significant opportunity to play a leading role in the broad distribution of LNG in Central America and the Caribbean

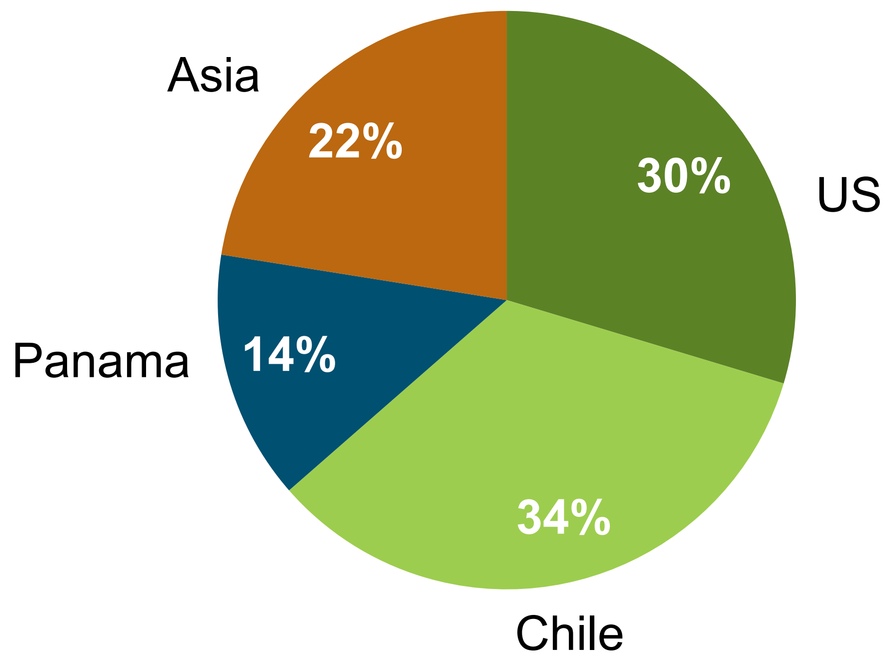
Leveraging Our Platform for Long-Term Growth



Contains Forward-Looking Statements

Leveraging Our Platforms: $1.5 Billion in Equity for Projects Currently Under Construction Yields ~15% Return[1]

$8.5 Billion Total Cost; AES Equity Commitment of $1.5 Billion, of Which Only $370 Million is Still to be Funded



64% of Required Equity is for Projects at IPL (US) & Gener (Chile)

1. Based on 3-year average contributions from all projects under construction and IPL MATS and wastewater upgrades, once all projects under construction are completed.

Construction Project: Masinloc 2 in the Philippines

335 MW Expansion

- Completion expected in 1H 2019
- Benefits from robust electricity demand growth
- Will be one of the most flexible, efficient and low-cost plants in the Philippines
- $740 million total project cost to be funded with debt capacity and free cash flow generated at Masinloc 1

Construction Project: Colon in Panama

380 MW CCGT and 180,000 m^3 LNG Storage Tank and Regasification Facility

- Panama's first natural gas-fired generation plant
- Power plant contracted under a 10-year, U.S. Dollar-denominated PPA
- Leveraging our experience with our existing LNG facility in the Dominican Republic
- Completion of the CCGT in 2018 and the LNG facility in 2019

- Total project cost of ~$1 billion and AES equity of ~$200 million

Advanced Stage Development Project: Southland Repowering in California

1,384 MW Under 20-Year Power Purchase Agreements

- 1,284 MW of combined cycle natural gas and 100 MW of battery-based energy storage capacity
- Recently signed turbine supply agreements and EPC contracts for the CCGT
- Expect to break ground in 2017, with operations in 2020 and 2021

- Expected total project cost of ~$2 billion and ~$500 million of equity from AES and potentially a partner

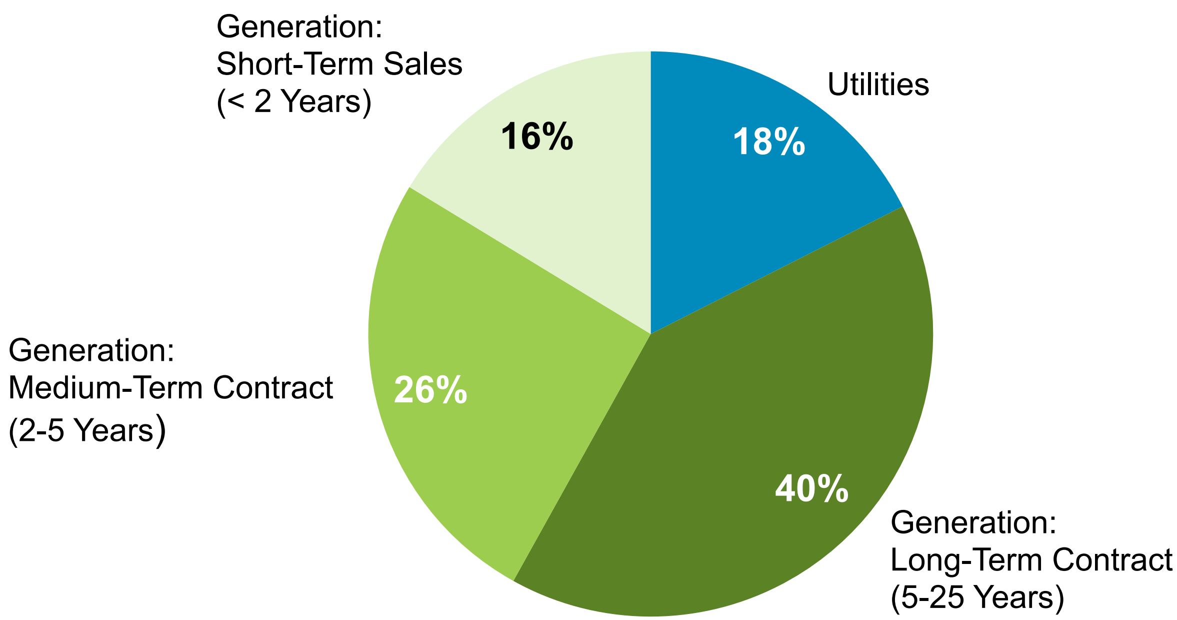
World Leader in Battery-Based Energy Storage

394 MW in Operation, Construction or Late Stage Development

- 136 MW in operation
- 30 MW under construction and coming on-line in 2016
- 228 MW in advanced stage development
- Growth through two paths:
  - AES-owned projects
  - Sales by AES and our channel partners to utilities and other customers

84% of Businesses are Contracted Generation or Utilities

2016 Expected Adjusted PTC[1] by Type of Business and Contract Length



2016: Average Remaining Contract Term is 7 Years[2]; Increases to ~10 Years[2,3] by 2020 as New Projects Come On-Line

1. A non-GAAP financial measure. See Appendix for definition and reconciliation.
2. Average of medium- and long-term contracts. PPA MW-weighted average is adjusted for AES' ownership stake.
3. Includes projects currently under construction and coming on-line before 2020, as well as the Southland re-powering project.

De-Risking Our Portfolio & De-Levering Our Balance Sheet

De-Risking and De-Levering: On Track to Achieve Strong BB Credit Stats by 2018

FitchRatings
Revised
Outlook From
Negative to Stable
Rated **BB-**

S&P Global
Upgraded Credit
Rating From
BB- to BB
Outlook: **Stable**

SEPT 2011 | DEC 2015 | JAN 2016 | FEB | MAR | APR

Exited
11 Markets

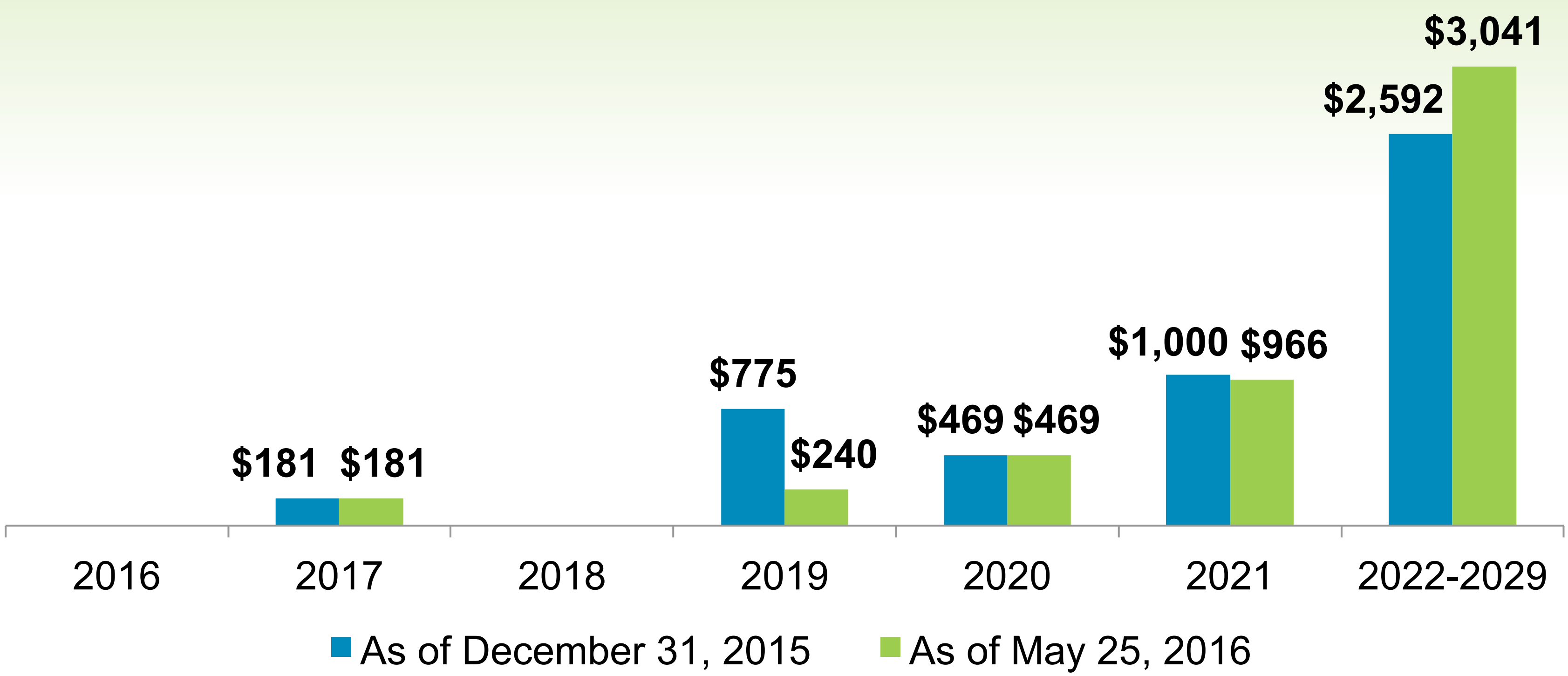
Reduced Parent Debt by
$1.5 B or 24%

MOODY'S
Revised
Credit Outlook From
Stable to Positive
Rated **Ba3**

Reduced Parent Debt Maturities by $535 Million through 2019

$ in Millions

In 2016, Prepaid $125 and Refinanced $495 of 2019 Maturities with Longer-Term Debt

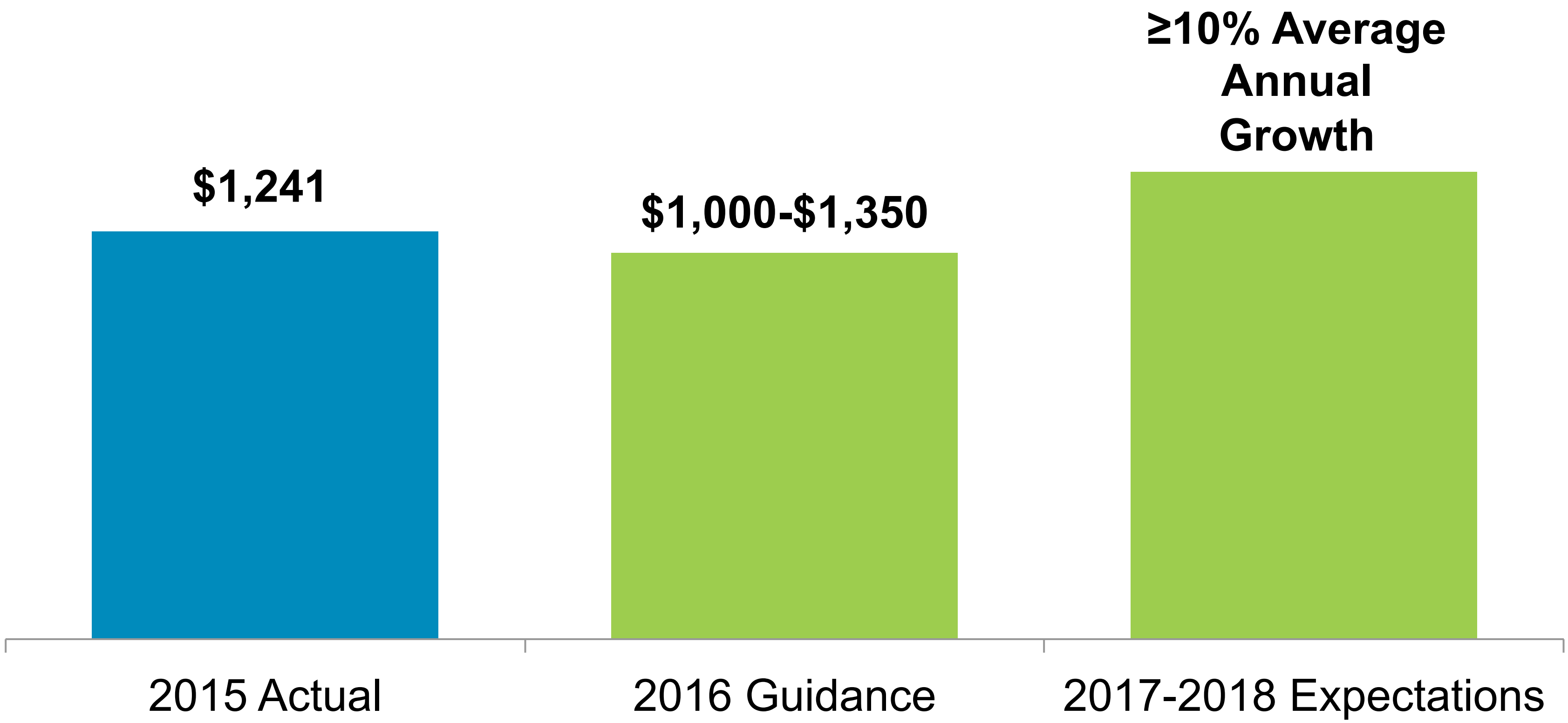


AES
we are the energy

Guidance & Expectations

Proportional Free Cash Flow[1]

$ in Millions

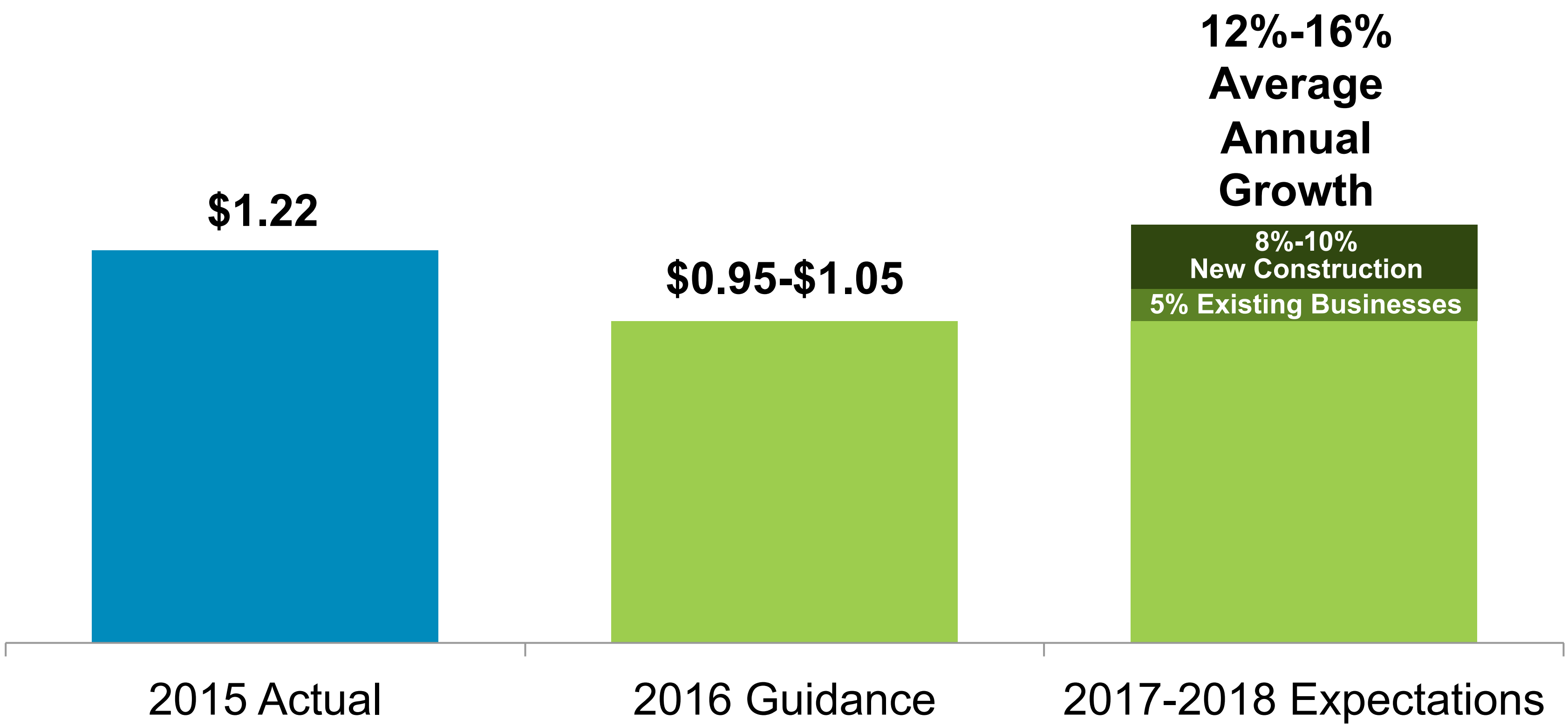


Free Cash Flow Yield Expected to Grow from 16% in 2016 to 19% in 2018[2]

Note: Guidance as of May 9, 2016.
1. A non-GAAP financial measure. See Appendix for definition.
2. Based on AES' share price of $11.09 on May 31, 2016.

Adjusted EPS[1] Growth Drivers

$ in Millions



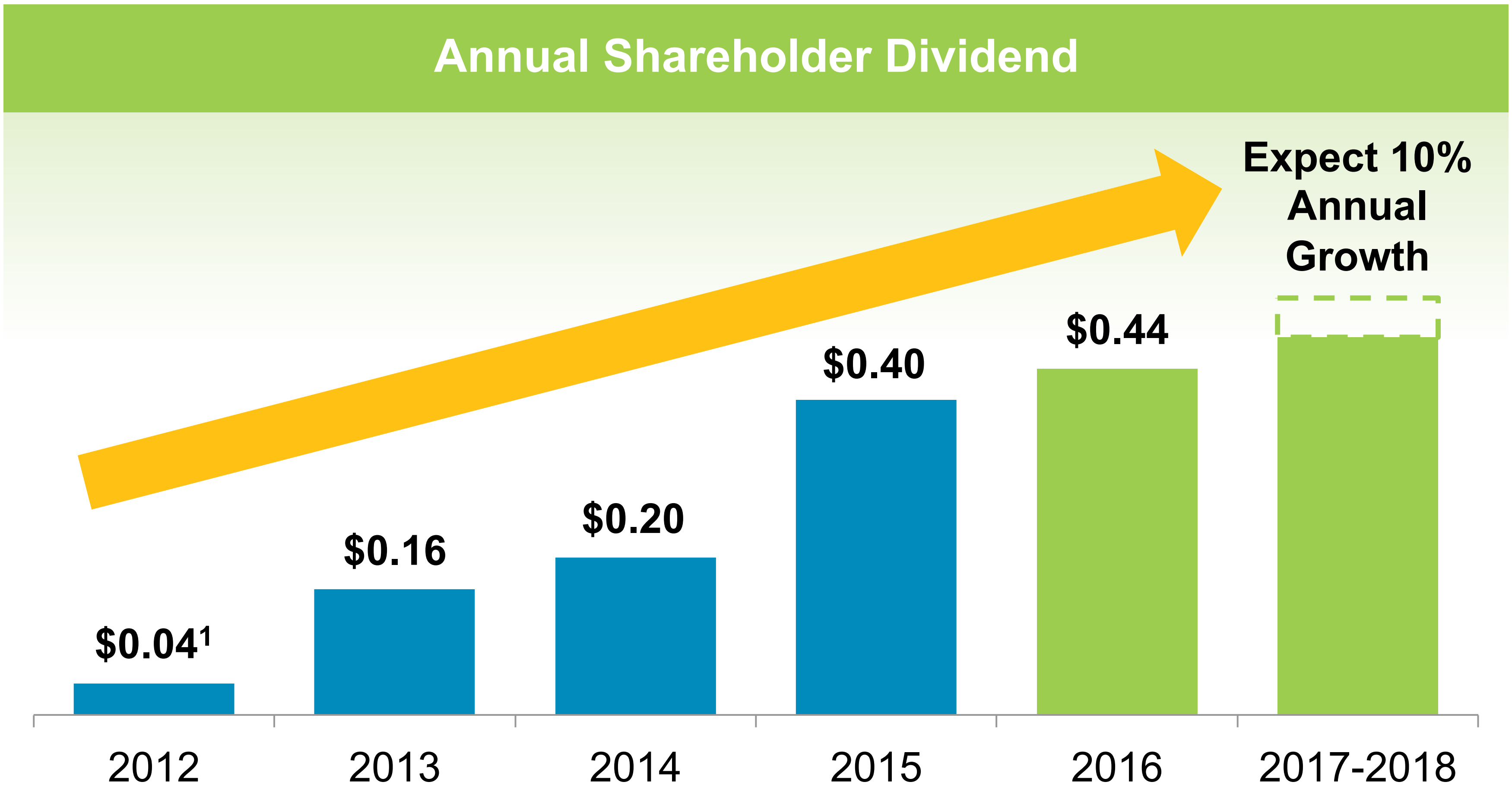
2017-2018: Expect High End of 12%-16% Average Annual Growth Range

Note: Guidance as of May 9, 2016.

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

Strong and Growing Free Cash Flow Supports Attractive Dividend Growth

$ in Millions



Note: Guidance as of May 9, 2016.

1. Initiated quarterly dividend in the fourth quarter of 2012.

Conclusion

- De-risking our portfolio and de-levering our Balance Sheet
- Stable cash flow from existing portfolio of mostly contracted generation and utility businesses
- Extending growth beyond 2018 by capitalizing on platform expansion opportunities
- Expecting double-digit growth in earnings and free cash flow as construction projects come on-line

Appendix

- Executive Compensation — Slide 24
- DPL Modeling Disclosures — Slide 25
- DPL and DP&L Non-Recourse Debt Schedule — Slide 26
- Currencies & Commodities — Slides 27-29
- Construction Program — Slide 30
- Reconciliation — Slide 31
- Assumptions & Definitions — Slides 32-34

Executive Compensation Aligned with Shareholders' Interests

81% Variable

	Compensation[1]	Key Factors
Restricted Stock Units	12%	Vests over 3 years
Performance Stock Units	24%	Vests over 3 years **Proportional Free Cash Flow[2]**
Performance Cash Units	24%	Vests over 3 years **Total Shareholder Return (3-Year vs. S&P 500 Utilities Index – 50%, S&P 500 Index – 25% & MSCI Emerging Markets Index – 25%)**
Annual Incentive	21%	**50% Financials[3]**; **10% Safety**; **15% Operations**; **25% Strategic Objectives**
Base Salary	19%	

81% of Target Compensation is Tied to Stock Price and/or Business Performance

1. 2016 target compensation for CEO and other Executive Officers.
2. A non-GAAP financial metric. See "definitions".
3. 20% Proportional Free Cash Flow, 20% Adjusted EPS and 10% Parent Free Cash Flow.

DPL Inc. Modeling Disclosures

Based on Market Conditions and Hedged Position as of April 30, 2016

	Balance of Year 2016	Full Year 2017	Full Year 2018
Volume Production (TWh)	9.7	14.4	14.3
% Volume Hedged	~52%	~52%	0%
Average Hedge Dark Spread ($/MWh)	$10.88	$12.49	N/A
EBITDA Generation Business[1] ($ in Millions)		$80 to $120 per year	
EBITDA DPL Inc. including Generation and T&D ($ in Millions)		~$340 to $350 million per year	
Reference Prices[2]			
Henry Hub Natural Gas ($/mmbtu)	$2.46	$3.01	$3.04
AEP-Dayton Hub ATC Prices ($/MWh)	$30	$32	$32
EBITDA Sensitivities (with Existing Hedges) ($ in Millions)			
+10% AD Hub Energy Price ATC ($/MWh)	$14	$22	$45
-10% AD Hub Energy Price ATC ($/MWh)	-$14	-$22	-$45

1. Includes capacity premium performance results.
2. Balance of Year 2016 (May-December), Full Year 2017 and Full Year 2018 based on forward curves as of April 30, 2016.

Non-Recourse Debt at DP&L and DPL Inc.

$ in Millions

Series	Interest Rate	Maturity	Amount Outstanding as of March 31, 2016	Remarks
2013 First Mortgage Bonds	**1.875%**	**Sept. 2016**	**$445.0**	• **Callable at make-whole T+20**
2005 Boone County, KY PCBs	4.7%	Jan. 2028	-	• Retired on July 1
2005 OH Air Quality PCBs	4.8%	Jan. 2034	-	• Retired on Aug. 3
2005 OH Water Quality PCBs	4.8%	Jan. 2034	-	• Retired on July 1
2006 OH Air Quality PCBs	4.8%	Sept. 2036	$100.0	• Non-callable; at par in Sept. 2016
2008 OH Air Quality PCBs (VDRNs)	Variable	Nov. 2040	-	• Retired on Aug. 3
2015 Direct Purchase Tax Exempt TL	Variable	Aug. 2020 (put)	$200.0	• Redeemable at par on any day
Total Pollution Control	**Various**	**Various**	**$300.0**	
Wright-Patterson AFB Note	**4.2%**	**Feb. 2061**	**$18.1**	• **No prepayment option**
2015 DP&L Revolver	**Variable**	**July 2020**	-	• **Pre-payable on any day**
DP&L Preferred	**3.8%**	**N/A**	**$22.9**	• **Redeemable at pre-established premium**
Total DP&L			**$786.0**	
2018 Term Loan	**Variable**	**May 2018**	**$125.0**	• **No prepayment penalty**
2016 Senior Unsecured	6.5%	Oct. 2016	$57.0	• Callable make-whole T+50
2019 Senior Unsecured	6.75%	Oct. 2019	$200.0	• Callable at make-whole T+50
2021 Senior Unsecured	7.25%	Oct. 2021	$780.0	• Callable at make-whole T+50
Total Senior Unsecured Bonds	**Various**	**Various**	**$1,037.0**	
2015 DPL Revolver	**Variable**	**July 2020**	**-**	• **Pre-payable on any day**
2001 Cap Trust II Securities	**8.125%**	**Sept. 2031**	**$15.6**	• **Non-callable**
Total DPL Inc.			**$1,177.6**	
TOTAL			**$1,963.6**	

Balance of Year 2016 Guidance Estimated Sensitivities

Interest Rates[1]

- 100 bps move in interest rates over year-to-go 2016 is equal to a change in EPS of approximately $0.020
- 10% appreciation in USD against the following key currencies is equal to the following negative EPS impacts:

Currencies

	Balance of Year 2016	
	Average Rate	Sensitivity
Argentine Peso (ARS)	15.43	$0.005
Brazilian Real (BRL)	3.56	Less than $0.005
Colombian Peso (COP)	2,911	$0.005
Euro (EUR)	1.15	Less than $0.005
Great British Pound (GBP)	1.46	Less than $0.005
Kazakhstan Tenge (KZT)	341.1	Less than $0.005

Commodity Sensitivity

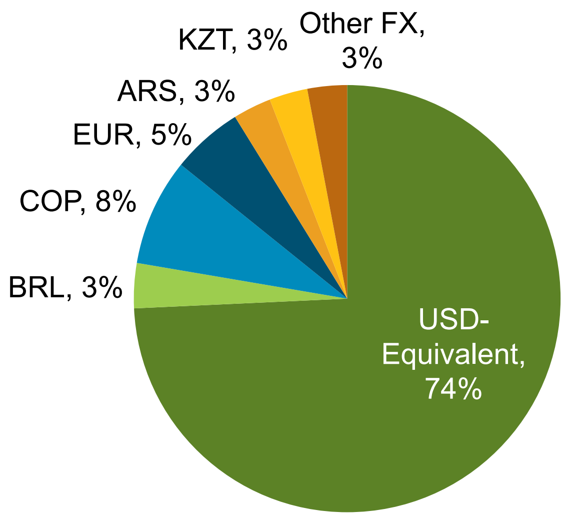
10% increase in commodity prices is forecasted to have the following EPS impacts:	Balance of Year 2016	
	Average Rate	Sensitivity
NYMEX Coal	$45/ton	$0.010, negative correlation
Rotterdam Coal (API 2)	$47/ton	
NYMEX WTI Crude Oil	$47/bbl	$0.005, positive correlation
IPE Brent Crude Oil	$48/bbl	
NYMEX Henry Hub Natural Gas	$2.5/mmbtu	Less than $0.005, positive correlation
UK National Balancing Point Natural Gas	£0.31/therm	
US Power (DPL) – PJM AD Hub	$ 30/MWh	$0.015, positive correlation

Note: Guidance provided on May 9, 2016. Sensitivities are provided on a standalone basis, assuming no change in the other factors, to illustrate the magnitude and direction of changing market factors on AES' results. Estimates show the impact the year-to-go 2016 Adjusted EPS. Actual results may differ from the sensitivities provided due to execution of risk management strategies, local market dynamics and operational factors. Full year 2016 guidance is based on currency and commodity forward curves and forecasts as of April 30, 2016. There are inherent uncertainties in the forecasting process and actual results may differ from projections. The Company undertakes no obligation to update the guidance presented today. Please see Item 3 of the Form 10-Q for a more complete discussion of this topic. AES has exposure to multiple coal, oil, and natural gas, and power indices; forward curves are provided for representative liquid markets. Sensitivities are rounded to the nearest ½ cent per share.

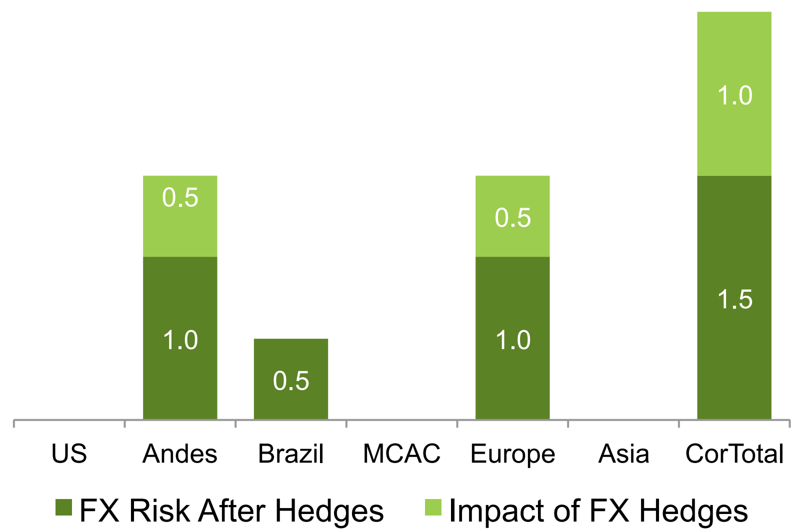
1. The move is applied to the floating interest rate portfolio balances as of April 30, 2016.

2016 Foreign Exchange (FX) Risk Mitigated Through Structuring of Our Businesses and Active Hedging

2016 Full Year FX Sensitivity[2,3] by SBU (Cents Per Share)



2016 Full Year FX Sensitivity[2,3] by SBU (Cents Per Share)

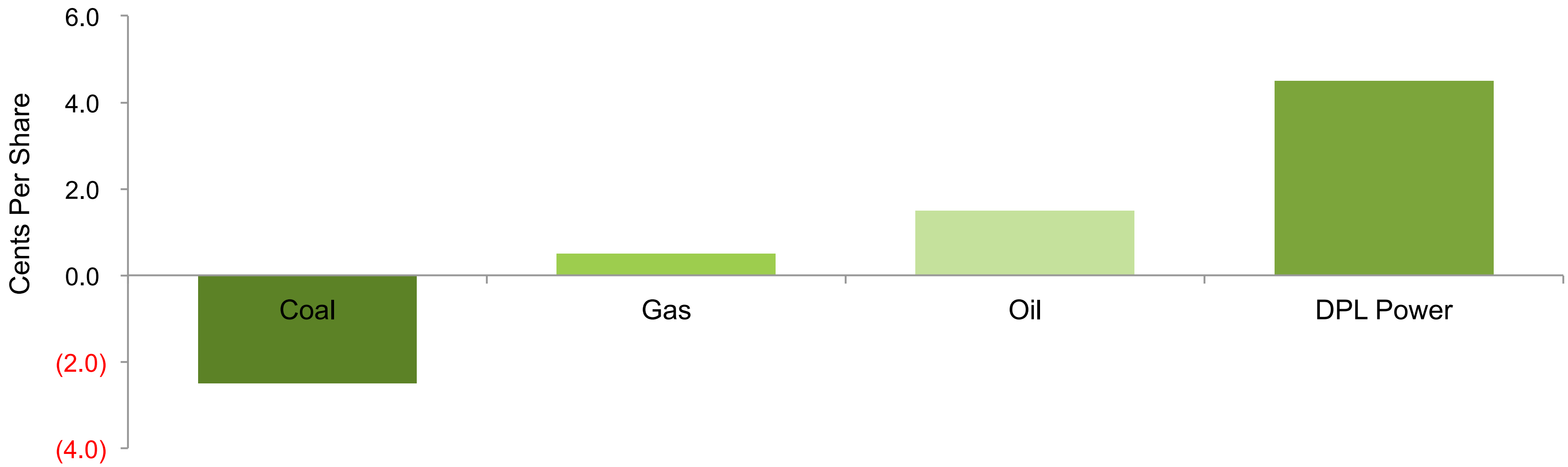


- 2016 correlated FX risk after hedges is $0.015 for 10% USD appreciation
- 74% of 2016 earnings effectively USD
  - USD-based economies (i.e. U.S., Panama)
  - Structuring of our contracts
- FX risk mitigated on a rolling basis by shorter-term active FX hedging programs

1. Before Corporate Charges. A non-GAAP financial measure. See “definitions” and Slide 31 for reconciliation.
2. Sensitivity represents full year 2016 exposure to a 10% appreciation of USD relative to foreign currency as of December 31, 2015.
3. Andes includes Argentina and Colombia businesses only due to limited translational impact of USD appreciation to Chilean businesses.

Commodity Exposure is Largely Hedged Through 2016, Long on US Power and Oil in Medium- to Long-Term

Full Year 2018 Adjusted EPS[1] Commodity Sensitivity[2] for 10% Change in Commodity Prices



- Mostly hedged through 2016, more open positions in a longer term is the primary driver of increase in commodity sensitivity

1. A non-GAAP financial measure. See "definitions".
2. Domestic and International sensitivities are combined and assumes each fuel category moves 10%. Adjusted EPS is negatively correlated to coal price movement, and positively correlated to gas, oil and power price movements.

Attractive Returns from Construction Pipeline

$ in Millions, Unless Otherwise Stated

Project	Country	AES Ownership	Fuel	Gross MW	Expected COD	Total Capex	Total AES Equity	ROE	Comments
Construction Projects Coming On-Line 2016-2018									
Andes Solar	Chile	67%	Solar	21	1H 2016	$44	$29		
Tunjita	Colombia	67%	Hydro	20	1H 2016	$67	$2[1]		Lease capital structure at Chivor
IPL MATS	US-IN	70%	Coal		1H 2016	$454	$143		Environmental (MATS) upgrades of 1,713 MW
Harding Street Units 5-7	US-IN	70%	Gas	630	1H 2016	$143	$45		
Cochrane	Chile	40%	Coal	532	2H 2016	$1,365	$142		
Eagle Valley CCGT	US-IN	70%	Gas	671	1H 2017	$590	$186		
DPP Conversion	Dominican Republic	90%	Gas	122	1H 2017	$260	$0		
IPL Wastewater	US-IN	70%	Gas		2H 2017	$224	$71		Environmental (NPDES) upgrades of 1,864 MW
OPGC 2	India	49%	Coal	1,320	1H 2018	$1,585	$227		
Colon	Panama	50%	Gas	380	1H 2018	$950	$209		Regasification and LNG storage tank expected on-line in 2019
Alto Maipo	Chile	40%	Hydro	531	2H 2018/ 1H 2019	$2,053	$335		
Masinloc 2	Philippines	51%	Coal	335	1H 2019	$740	$110		
Total				**4,562**		**$8,475**	**$1,499**		
ROE[2]								**~15%**	**Weighted average; net income divided by AES equity contribution**
CASH YIELD[2]								**~15%**	**Weighted average; subsidiary distributions divided by AES equity contribution**

1. AES equity contribution equal to 67% of AES Gener's equity contribution to the project.
2. Based on projections. See our 2015 Form 10-K for further discussion of development and construction risks. Based on 3-year average contributions from all projects under construction and IPL MATS and wastewater upgrades, once all projects under construction are completed.

Reconciliation of 2016 Guidance

$ in Millions, Except Per Share Amounts

2016 Guidance	
Proportional Free Cash Flow[1]	$1,000-$1,350
Consolidated Net Cash Provided by Operating Activities	$2,000-$2,900
Adjusted EPS[1]	$0.95-$1.05

Reconciliation	Consolidated	Adjustment Factor	Proportional
Consolidated Net Cash Provided by Operating Activities (a)	$2,000-$2,900	$500-$1,050	$1,500-$1,850
Maintenance & Environmental Capital Expenditures (b)	$600-$800	$200	$400-$600
Free Cash Flow[1] (a - b)	$1,300-$2,200	$300-$850	$1,000-$1,350

- Commodity and foreign currency exchange rates and forward curves as of April 30, 2016

1. A non-GAAP financial measure. See "definitions".

Assumptions

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

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

Definitions

- **Adjusted Earnings Per Share** (a non-GAAP financial measure) is defined as diluted earnings per share from continuing operations excluding gains or losses of both consolidated entities and entities accounted for under the equity method due to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) gains or losses due to dispositions and acquisitions of business interests, (d) losses due to impairments, and (e) costs due to the early retirement of debt, adjusted for the same gains or losses excluded from consolidated entities. The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. AES believes that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose or acquire business interests or retire debt, which affect results in a given period or periods. Adjusted EPS should not be construed as an alternative to diluted earnings per share from continuing operations, which is determined in accordance with GAAP.
- **Adjusted Pre-Tax Contribution** (a non-GAAP financial measure) represents pre-tax income from continuing operations attributable to AES excluding gains or losses of both consolidated entities and entities accounted for under the equity method due to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) gains or losses due to dispositions and acquisitions of business interests, (d) losses due to impairments, and (e) costs due to the early retirement of debt, adjusted for the same gains or losses excluded from consolidated entities. It includes net equity in earnings of affiliates, on an after-tax basis. The GAAP measure most comparable to Adjusted PTC is income from continuing operations attributable to AES. AES believes that Adjusted PTC better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose or acquire business interests or retire debt, which affect results in a given period or periods. Earnings before tax represents the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the affects of tax planning, corresponding to the various jurisdictions in which the Company operates. Adjusted PTC should not be construed as an alternative to income from continuing operations attributable to AES, which is determined in accordance with GAAP.
- **Free Cash Flow** (a non-GAAP financial measure) is defined as net cash from operating activities less maintenance capital expenditures (including non-recoverable environmental capital expenditures), net of reinsurance proceeds from third parties. AES believes that free cash flow is a useful measure for evaluating our financial condition because it represents the amount of cash provided by operations less maintenance capital expenditures as defined by our businesses, that may be available for investing or for repaying debt. Free cash flow should not be construed as an alternative to net cash from operating activities, which is determined in accordance with GAAP.
- **Net Debt** (a non-GAAP financial measure) is defined as current and non-current recourse and non-recourse debt less cash and cash equivalents, restricted cash, short term investments, debt service reserves and other deposits. AES believes that net debt is a useful measure for evaluating our financial condition because it is a standard industry measure that provides an alternate view of a company's indebtedness by considering the capacity of cash. It is also a required component of valuation techniques used by management and the investment community.
- **Parent Company Liquidity** (a non-GAAP financial measure) is defined as cash at the Parent Company plus availability under corporate credit facilities plus cash at qualified holding companies ("QHCs"). AES believes that unconsolidated Parent Company liquidity is important to the liquidity position of AES as a Parent Company because of the non-recourse nature of most of AES' indebtedness.
- **Parent Free Cash Flow** (a non-GAAP financial measure) should not be construed as an alternative to Net Cash Provided by Operating Activities which is determined in accordance with GAAP. Parent Free Cash Flow is equal to Subsidiary Distributions less cash used for interest costs, development, general and administrative activities, and tax payments by the Parent Company. Parent Free Cash Flow is used for dividends, share repurchases, growth investments, recourse debt repayments, and other uses by the Parent Company.

Definitions (Continued)

- **Proportional Free Cash Flow** – The Company defines Proportional Free Cash Flow as cash flows from operating activities (adjusted for service concession asset capital expenditures), less maintenance capital expenditures (including non-recoverable environmental capital expenditures and net of reinsurance proceeds), adjusted for the estimated impact of noncontrolling interests. The proportionate share of cash flows and related adjustments attributable to noncontrolling interests in our subsidiaries comprise the proportional adjustment factor. Upon the Company's adoption of the accounting guidance for service concession arrangements effective January 1, 2015, capital expenditures related to service concession assets that would have been classified as investing activities on the Condensed Consolidated Statement of Cash Flows are now classified as operating activities.
  The Company excludes environmental capital expenditures that are expected to be recovered through regulatory, contractual or other mechanisms. An example of recoverable environmental capital expenditures is IPL's investment in MATS-related environmental upgrades that are recovered through a tracker.
  The GAAP measure most comparable to proportional free cash flow is cash flows from operating activities. We believe that proportional free cash flow better reflects the underlying business performance of the Company, as it measures the cash generated by the business, after the funding of maintenance capital expenditures, that may be available for investing or repaying debt or other purposes. Factors in this determination include the impact of noncontrolling interests, where AES consolidates the results of a subsidiary that is not wholly owned by the Company.
- **Proportional Metrics –** The Company is a holding company that derives its income and cash flows from the activities of its subsidiaries, some of which are not wholly-owned by the Company. Accordingly, the Company has presented certain financial metrics which are defined as Proportional (a non-GAAP financial measure) to account for the Company's ownership interest.
  Proportional metrics present the Company's estimate of its share in the economics of the underlying metric. The Company believes that the Proportional metrics are useful to investors because they exclude the economic share in the metric presented that is held by non-AES shareholders. For example, Operating Cash Flow is a GAAP metric which presents the Company's cash flow from operations on a consolidated basis, including operating cash flow allocable to noncontrolling interests. Proportional Operating Cash Flow removes the share of operating cash flow allocable to noncontrolling interests and therefore may act as an aid in the valuation the Company. Beginning in Q1 2015, the definition was revised to also exclude cash flows related to service concession assets.
  Proportional metrics are reconciled to the nearest GAAP measure. Certain assumptions have been made to estimate our proportional financial measures. These assumptions include: (i) the Company's economic interest has been calculated based on a blended rate for each consolidated business when such business represents multiple legal entities; (ii) the Company's economic interest may differ from the percentage implied by the recorded net income or loss attributable to noncontrolling interests or dividends paid during a given period; (iii) the Company's economic interest for entities accounted for using the hypothetical liquidation at book value method is 100%; (iv) individual operating performance of the Company's equity method investments is not reflected and (v) inter-segment transactions are included as applicable for the metric presented.
  The proportional adjustment factor, proportional maintenance capital expenditures (net of reinsurance proceeds) and proportional non-recoverable environmental capital expenditures are calculated by multiplying the percentage owned by noncontrolling interests for each entity by its corresponding consolidated cash flow metric and are totaled to the resulting figures. For example, Parent Company A owns 20% of Subsidiary Company B, a consolidated subsidiary. Thus, Subsidiary Company B has an 80% noncontrolling interest. Assuming a consolidated net cash flow from operating activities of $100 from Subsidiary B, the proportional adjustment factor for Subsidiary B would equal $80 (or $100 x 80%). The Company calculates the proportional adjustment factor for each consolidated business in this manner and then sums these amounts to determine the total proportional adjustment factor used in the reconciliation. The proportional adjustment factor may differ from the proportion of income attributable to noncontrolling interests as a result of (a) non-cash items which impact income but not cash and (b) AES' ownership interest in the subsidiary where such items occur.
- **Subsidiary Liquidity** (a non-GAAP financial measure) is defined as cash and cash equivalents and bank lines of credit at various subsidiaries.
- **Subsidiary Distributions** should not be construed as an alternative to Net Cash Provided by Operating Activities which is determined in accordance with GAAP. Subsidiary Distributions are important to the Parent Company because the Parent Company is a holding company that does not derive any significant direct revenues from its own activities but instead relies on its subsidiaries' business activities and the resultant distributions to fund the debt service, investment and other cash needs of the holding company. The reconciliation of the difference between the Subsidiary Distributions and Net Cash Provided by Operating Activities consists of cash generated from operating activities that is retained at the subsidiaries for a variety of reasons which are both discretionary and non-discretionary in nature. These factors include, but are not limited to, retention of cash to fund capital expenditures at the subsidiary, cash retention associated with non-recourse debt covenant restrictions and related debt service requirements at the subsidiaries, retention of cash related to sufficiency of local GAAP statutory retained earnings at the subsidiaries, retention of cash for working capital needs at the subsidiaries, and other similar timing differences between when the cash is generated at the subsidiaries and when it reaches the Parent Company and related holding companies.

APPENDIX A

QUALIFICATIONS OF

MATTHEW I. KAHAL

MATTHEW I. KAHAL

Since 2001, Mr. Kahal has worked as an independent consulting economist, specializing in energy economics, public utility regulation, and utility financial studies. Over the past three decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing, environmental compliance, and utility financial issues. In the financial area, he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone, and water utilities. Mr. Kahal's work in recent years has expanded to electric power markets, mergers, and various aspects of regulation.

Mr. Kahal has provided expert testimony in more than 400 cases before state and federal regulatory commissions, federal courts, and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring, and various other regulatory and public policy issues.

Education

B.A. (Economics) – University of Maryland, 1971

M.A. (Economics) – University of Maryland, 1974

Ph.D. candidacy – University of Maryland, completed all course work and qualifying examinations.

Previous Employment

1981-2001	Founding Principal, Vice President, and President Exeter Associates, Inc. Columbia, MD
1980-1981	Member of the Economic Evaluation Directorate The Aerospace Corporation Washington, D.C.
1977-1980	Consulting Economist Washington, D.C. consulting firm
1972-1977	Research/Teaching Assistant and Instructor (part time) Department of Economics, University of Maryland (College Park) Lecturer in Business and Economics Montgomery College (Rockville and Takoma Park, MD)

Professional Experience

Mr. Kahal has more than thirty-five years' experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc., and for the next 20 years he served as a Principal and corporate officer of the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted by both Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring, and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity, he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College, teaching courses on economic principles, business, and economic development.

Publications and Consulting Reports

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980 (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983 (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities" (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes (with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting" (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk" (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985 (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company – Past and Present, prepared for the Texas Public Utility Commission, December 1985 (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

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Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum).

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994, prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

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Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.).

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).
The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005 (prepared for the Chesapeake Bay Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005, with Phil Hayet (prepared for the Louisiana Public Service Commission).

Expert Report on Capital Structure, Equity and Debt Costs, prepared for the Edmonton Regional Water Customers Group, August 30, 2006.

Maryland's Options to Reduce and Stabilize Electric Power Prices Following Restructuring, with Steven L. Estomin, prepared for the Power Plant Research Program, Maryland Department of Natural Resources, September 2006.

Expert Report of Matthew I. Kahal, on behalf of the U. S. Department of Justice, August 2008, Civil Action No. IP-99-1693C-MIS.

Conference and Workshop Presentations

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty-Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995 (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen '97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers' Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, Baton Rouge, Louisiana, October 2, 2002 (presentation on Performance-Based Ratemaking and panelist on RTO issues).

Virginia State Corporation Commission/Virginia State Bar, Twenty-Second National Regulatory Conference, Williamsburg, Virginia, May 10, 2004 (presentation on Electric Transmission System Planning).

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	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic Impacts of Proposed Rate Increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load Forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test Year Sales and Revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test Year Sales, Revenues, Costs, and Load Forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-Use Pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load Forecasting, Marginal Cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for Plant, Load Forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA Standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-Use Pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-Use Rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting, Load Management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA Standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of Return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of Return, CWIP

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16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of Return, Capital Structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of Equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of Return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of Return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of Return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of Return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of Return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of Return

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31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of Return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of Return, capital Structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of Return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of Return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of Return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of Return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of Return

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46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of Return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of Return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of Return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of Return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of Return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

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61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of Return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of Return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of Return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of Return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of Return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of Return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

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75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of Return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of Return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	N/A	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of Return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of Return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of Return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of Return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power

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89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of Return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of Return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of Return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of Return
99.	90-256 January 1991	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
100.	U-17949A February 1991	South Central Bell Telephone Company	Louisiana	Louisiana PSC	Rate of Return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of Return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Environmental controls

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103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Company Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Company	New Jersey	Rate Counsel	Rate of Return
108.	91-5032 August 1991	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of Return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of Return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of Return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of Return
116.	P-870235, et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts

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117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of Return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of Return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of Return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of Return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of Return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of Return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power Supply Clause

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131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of Return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger Issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power Plant Certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of Return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of Return
137.	P-00930715 December 1993	Bell Telephone Company of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return, Financial Projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
139.	8583 February 1994	Conowingo Power Company	Maryland	Dept. of Natural Resources	Competitive Bidding for Power Supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Company	Minnesota	Attorney General	Rate of Return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of Return
142.	92-345, Phase II June 1994	Central Maine Power Company	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Company	Nevada	Federal Executive Agencies	Rate of Return
144.	94-0065 May 1994	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Rate of Return
145.	GR94010002J June 1994	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return

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146.	WR94030059 July 1994	New Jersey-American Water Company	New Jersey	Rate Counsel	Rate of Return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Company	Rate of Return
149.	R-00942986 July 1994	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, Emission Allowances
150.	94-121 August 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger Savings and Allocations
152.	IPC-E-94-5 November 1994	Idaho Power Company	Idaho	Federal Executive Agencies	Rate of Return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of Return (Rebuttal Only)
154.	90-256 December 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of Return Industrial Contracts Trust Fund Earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of Return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of Return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class Cost of Service Issues

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160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of Return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of Return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of Capital Spending Program
163.	ER95-625-000, et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of Return
164.	P-00950915, et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration Contract Amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of Equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of Return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of Return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of Return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues

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175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition

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189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan

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203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000, et al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation
210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations

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217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453, et al. July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453, et al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Connectivity	Maryland	MD Energy Administration	Merger Issues

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231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001, et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return
239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242.	8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Company of Colorado	Colorado	Fed. Executive Agencies	Rate of Return

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246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Company	U.S. District Court	U.S. Department of Justice, et al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Company	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return

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261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Company	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant Purchase and Cost Recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings
269.	EF03070532 March 2005	Public Service Electric & Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan

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276.	U-27866-A September 2005	Southwestern Electric Power Company	Louisiana	LPSC Staff	Purchase Power Contract
277.	U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278.	U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279.	A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280.	EM05020106 November 2005	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Merger Issues
281.	U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Plant Certification, Financing, Rate Plan
282.	U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283.	U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284.	A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring
285.	9056 March 2006	Generic	Maryland	Maryland Energy Administration	Standard Offer Service Structure
286.	C2-99-1182 April 2006	American Electric Power Utilities	U. S. District Court Southern District, Ohio	U. S. Department of Justice	New Source Review Enforcement (expert report)
287.	EM05121058 April 2006	Atlantic City Electric	New Jersey	Ratepayer Advocate	Power plant Sale
288.	ER05121018 June 2006	Jersey Central Power & Light Company	New Jersey	Ratepayer Advocate	NUG Contracts Cost Recovery
289.	U-21496, Subdocket C June 2006	Cleco Power LLC	Louisiana	Commission Staff	Rate Stabilization Plan
290.	GR0510085 June 2006	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Rate of Return (gas services)

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291.	R-000061366 July 2006	Metropolitan Ed. Company Penn. Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
292.	9064 September 2006	Generic	Maryland	Energy Administration	Standard Offer Service
293.	U-29599 September 2006	Cleco Power LLC	Louisiana	Commission Staff	Purchase Power Contracts
294.	WR06030257 September 2006	New Jersey American Water Company	New Jersey	Rate Counsel	Rate of Return
295.	U-27866/U-29702 October 2006	Southwestern Electric Power Company	Louisiana	Commission Staff	Purchase Power/Power Plant Certification
296.	9063 October 2006	Generic	Maryland	Energy Administration Department of Natural Resources	Generation Supply Policies
297.	EM06090638 November 2006	Atlantic City Electric	New Jersey	Rate Counsel	Power Plant Sale
298.	C-2000065942 November 2006	Pike County Light & Power	Pennsylvania	Consumer Advocate	Generation Supply Service
299.	ER06060483 November 2006	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
300.	A-110150F0035 December 2006	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
301.	U-29203, Phase II January 2007	Entergy Gulf States Entergy Louisiana	Louisiana	Commission Staff	Storm Damage Cost Allocation
302.	06-11022 February 2007	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
303.	U-29526 March 2007	Cleco Power	Louisiana	Commission Staff	Affiliate Transactions
304.	P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
305.	P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate	Provider of Last Resort Service

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306.	EM07010026 May 2007	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Power Plant Sale
307.	U-30050 June 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
308.	U-29956 June 2007	Entergy Louisiana	Louisiana	Commission Staff	Black Start Unit
309.	U-29702 June 2007	Southwestern Electric Power Company	Louisiana	Commission Staff	Power Plant Certification
310.	U-29955 July 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contracts
311.	2007-67 July 2007	FairPoint Communications	Maine	Office of Public Advocate	Merger Financial Issues
312.	P-00072259 July 2007	Metropolitan Edison Co.	Pennsylvania	Office of Consumer Advocate	Purchase Power Contract Restructuring
313.	EO07040278 September 2007	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Energy Program Financial Issues
314.	U-30192 September 2007	Entergy Louisiana	Louisiana	Commission Staff	Power Plant Certification Ratemaking, Financing
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration	Standard Offer Service Reliability
316.	U-30050 November 2007	Entergy Gulf States	Louisiana	Commission Staff	Power Plant Acquisition
317.	IPC-E-07-8 December 2007	Idaho Power Co.	Idaho	U.S. Department of Energy	Cost of Capital
318.	U-30422 (Phase I) January 2008	Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
319.	U-29702 (Phase II) February, 2008	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Certification
320.	March 2008	Delmarva Power & Light	Delaware State Senate	Senate Committee	Wind Energy Economics

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321.	U-30192 (Phase II) March 2008	Entergy Louisiana	Louisiana	Commission Staff	Cash CWIP Policy, Credit Ratings
322.	U-30422 (Phase II) April 2008	Entergy Gulf States - LA	Louisiana	Commission Staff	Power Plant Acquisition
323.	U-29955 (Phase II) April 2008	Entergy Gulf States - LA Entergy Louisiana	Louisiana	Commission Staff	Purchase Power Contract
324.	GR-070110889 April 2008	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of Capital
325.	WR-08010020 July 2008	New Jersey American Water Company	New Jersey	Rate Counsel	Cost of Capital
326.	U-28804-A August 2008	Entergy Louisiana	Louisiana	Commission Staff	Cogeneration Contract
327.	IP-99-1693C-M/S August 2008	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/ Environmental Protection Agency	Clean Air Act Compliance (Expert Report)
328.	U-30670 September 2008	Entergy Louisiana	Louisiana	Commission Staff	Nuclear Plant Equipment Replacement
329.	9149 October 2008	Generic	Maryland	Department of Natural Resources	Capacity Adequacy/Reliability
330.	IPC-E-08-10 October 2008	Idaho Power Company	Idaho	U.S. Department of Energy	Cost of Capital
331.	U-30727 October 2008	Cleco Power LLC	Louisiana	Commission Staff	Purchased Power Contract
332.	U-30689-A December 2008	Cleco Power LLC	Louisiana	Commission Staff	Transmission Upgrade Project
333.	IP-99-1693C-M/S February 2009	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/EPA	Clean Air Act Compliance (Oral Testimony)
334.	U-30192, Phase II February 2009	Entergy Louisiana, LLC	Louisiana	Commission Staff	CWIP Rate Request Plant Allocation
335.	U-28805-B February 2009	Entergy Gulf States, LLC	Louisiana	Commission Staff	Cogeneration Contract

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336.	P-2009-2093055, et al. May 2009	Metropolitan Edison Pennsylvania Electric	Pennsylvania	Office of Consumer Advocate	Default Service
337.	U-30958 July 2009	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract
338.	EO08050326 August 2009	Jersey Central Power Light Co.	New Jersey	Rate Counsel	Demand Response Cost Recovery
339.	GR09030195 August 2009	Elizabethtown Gas	New Jersey	New Jersey Rate Counsel	Cost of Capital
340.	U-30422-A August 2009	Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase
341.	CV 1:99-01693 August 2009	Duke Energy Indiana	Federal District Court – Indiana	U. S. DOJ/EPA, et al.	Environmental Compliance Rate Impacts (Expert Report)
342.	4065 September 2009	Narragansett Electric	Rhode Island	Division Staff	Cost of Capital
343.	U-30689 September 2009	Cleco Power	Louisiana	Staff	Cost of Capital, Rate Design, Other Rate Case Issues
344.	U-31147 October 2009	Entergy Gulf States Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
345.	U-30913 November 2009	Cleco Power	Louisiana	Staff	Certification of Generating Unit
346.	M-2009-2123951 November 2009	West Penn Power	Pennsylvania	Office of Consumer Advocate	Smart Meter Cost of Capital (Surrebuttal Only)
347.	GR09050422 November 2009	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Cost of Capital
348.	D-09-49 November 2009	Narragansett Electric	Rhode Island	Division Staff	Securities Issuances
349.	U-29702, Phase II November 2009	Southwestern Electric Power Company	Louisiana	Commission Staff	Cash CWIP Recovery
350.	U-30981 December 2009	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Storm Damage Cost Allocation

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351.	U-31196 (ITA Phase) February 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
352.	ER09080668 March 2010	Rockland Electric	New Jersey	Rate Counsel	Rate of Return
353.	GR10010035 May 2010	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of Return
354.	P-2010-2157862 May 2010	Pennsylvania Power Co.	Pennsylvania	Consumer Advocate	Default Service Program
355.	10-CV-2275 June 2010	Xcel Energy	U.S. District Court Minnesota	U.S. Dept. Justice/EPA	Clean Air Act Enforcement
356.	WR09120987 June 2010	United Water New Jersey	New Jersey	Rate Counsel	Rate of Return
357.	U-30192, Phase III June 2010	Entergy Louisiana	Louisiana	Staff	Power Plant Cancellation Costs
358.	31299 July 2010	Cleco Power	Louisiana	Staff	Securities Issuances
359.	App. No. 1601162 July 2010	EPCOR Water	Alberta, Canada	Regional Customer Group	Cost of Capital
360.	U-31196 July 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
361.	2:10-CV-13101 August 2010	Detroit Edison	U.S. District Court Eastern Michigan	U.S. Dept. of Justice/EPA	Clean Air Act Enforcement
362.	U-31196 August 2010	Entergy Louisiana Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase and Cost Recovery
363.	Case No. 9233 October 2010	Potomac Edison Company	Maryland	Energy Administration	Merger Issues
364.	2010-2194652 November 2010	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default Service Plan
365.	2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues

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366.	U-31841 May 2011	Entergy Gulf States	Louisiana	Staff	Purchase Power Agreement
367.	11-06006 September 2011	Nevada Power	Nevada	U. S. Department of Energy	Cost of Capital
368.	9271 September 2011	Exelon/Constellation	Maryland	MD Energy Administration	Merger Savings
369.	4255 September 2011	United Water Rhode Island	Rhode Island	Division of Public Utilities	Rate of Return
370.	P-2011-2252042 October 2011	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default service plan
371.	U-32095 November 2011	Southwestern Electric Power Company	Louisiana	Commission Staff	Wind energy contract
372.	U-32031 November 2011	Entergy Gulf States Louisiana	Louisiana	Commission Staff	Purchased Power Contract
373.	U-32088 January 2012	Entergy Louisiana	Louisiana	Commission Staff	Coal plant evaluation
374.	R-2011-2267958 February 2012	Aqua Pa.	Pennsylvania	Office of Consumer Advocate	Cost of capital
375.	P-2011-2273650 February 2012	FirstEnergy Companies	Pennsylvania	Office of Consumer Advocate	Default service plan
376.	U-32223 March 2012	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract and Rate Recovery
377.	U-32148 March 2012	Entergy Louisiana Energy Gulf States	Louisiana	Commission Staff	RTO Membership
378.	ER11080469 April 2012	Atlantic City Electric	New Jersey	Rate Counsel	Cost of capital
379.	R-2012-2285985 May 2012	Peoples Natural Gas Company	Pennsylvania	Office of Consumer Advocate	Cost of capital
380.	U-32153 July 2012	Cleco Power	Louisiana	Commission Staff	Environmental Compliance Plan

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381.	U-32435 August 2012	Entergy Gulf States Louisiana LLC	Louisiana	Commission Staff	Cost of equity (gas)
382.	ER-2012-0174 August 2012	Kansas City Power & Light Company	Missouri	U. S. Department of Energy	Rate of return
383.	U-31196 August 2012	Entergy Louisiana/ Entergy Gulf States	Louisiana	Commission Staff	Power Plant Joint Ownership
384.	ER-2012-0175 August 2012	KCP&L Greater Missouri Operations	Missouri	U.S. Department of Energy	Rate of Return
385.	4323 August 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Rate of Return (electric and gas)
386.	D-12-049 October 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Debt issue
387.	GO12070640 October 2012	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of capital
388.	GO12050363 November 2012	South Jersey Gas Company	New Jersey	Rate Counsel	Cost of capital
389.	R-2012-2321748 January 2013	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Cost of capital
390.	U-32220 February 2013	Southwestern Electric Power Co.	Louisiana	Commission Staff	Formula Rate Plan
391.	CV No. 12-1286 February 2013	PPL et al.	Federal District Court	MD Public Service Commission	PJM Market Impacts (deposition)
392.	EL13-48-000 February 2013	BGE, PHI subsidiaries	FERC	Joint Customer Group	Transmission Cost of Equity
393.	EO12080721 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
394.	EO12080726 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
395.	CV12-1286MJG March 2013	PPL, PSEG	U.S. District Court for the District of Md.	Md. Public Service Commission	Capacity Market Issues (trial testimony)

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396.	U-32628 April 2013	Entergy Louisiana and Gulf States Louisiana	Louisiana	Staff	Avoided cost methodology
397.	U-32675 June 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	RTO Integration Issues
398.	ER12111052 June 2013	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Cost of capital
399.	PUE-2013-00020 July 2013	Dominion Virginia Power	Virginia	Apartment & Office Building Assoc. of Met. Washington	Cost of capital
400.	U-32766 August 2013	Cleco Power	Louisiana	Staff	Power plant acquisition
401.	U-32764 September 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	Storm Damage Cost Allocation
402.	P-2013-237-1666 September 2013	Pike County Light and Power Co.	Pennsylvania	Office of Consumer Advocate	Default Generation Service
403.	E013020155 and G013020156 October 2013	Public Service Electric and Gas Company	New Jersey	Rate Counsel	Cost of capital
404.	U-32507 November 2013	Cleco Power	Louisiana	Staff	Environmental Compliance Plan
405.	DE11-250 December 2013	Public Service Co. New Hampshire	New Hampshire	Consumer Advocate	Power plant investment prudence
406.	4434 February 2014	United Water Rhode Island	Rhode Island	Staff	Cost of Capital
407.	U-32987 February 2014	Atmos Energy	Louisiana	Staff	Cost of Capital
408.	EL 14-28-000 February 2014	Entergy Louisiana Entergy Gulf States	FERC	LPSC	Avoided Cost Methodology (affidavit)
409.	ER13111135 May 2014	Rockland Electric	New Jersey	Rate Counsel	Cost of Capital

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410.	13-2385-SSO, et al. May 2014	AEP Ohio	Ohio	Consumers' Counsel	Default Service Issues
411.	U-32779 May 2014	Cleco Power, LLC	Louisiana	Staff	Formula Rate Plan
412.	CV-00234-SDD-SCR June 2014	Entergy Louisiana Entergy Gulf	U.S. District Court Middle District Louisiana	Louisiana Public Service Commission	Avoided Cost Determination Court Appeal
413.	U-32812 July 2014	Entergy Louisiana	Louisiana	Louisiana Public Service Commission	Nuclear Power Plant Prudence
414.	14-841-EL-SSO September 2014	Duke Energy Ohio	Ohio	Office of Consumer' Counsel	Default Service Issues
415.	EM14060581 November 2014	Atlantic City Electric Company	New Jersey	Rate Counsel	Merger Financial Issues
416.	EL15-27 December 2014	BGE, PHI Utilities	FERC	Joint Complainants	Cost of Equity
417.	14-1297-EL-SSO December 2014	First Energy Utilities	Ohio	Consumer's Counsel and NOPEC	Default Service Issues
418.	EL-13-48-001 January 2015	BGE, PHI Utilities	FERC	Joint Complainants	Cost of Equity
419.	EL13-48-001 and EL15-27-000 April 2015	BGE and PHI Utilities	FERC	Joint Complainants	Cost of Equity
420.	U- 33592 November 2015	Entergy Louisiana	Louisiana Public Service Commission	Commission Staff	PURPA PPA Contract
421.	GM15101196 April 2016	AGL Resources	New Jersey	Rate Counsel	Financial Aspects of Merger
422.	U-32814 April 2016	Southwestern Electric Power	Louisiana	Staff	Wind Energy PPAs
423.	A-2015-2517036, et.al. April 2016	Pike County	Pennsylvania	Consumer Advocate	Merger Issues