BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters	)))	**Case No.10-501-EL-FOR**
In the Matter of the Long-Term Forecast Report of Columbus Southern Power Company and Related Matters	)))	**Case No.10-502-EL-FOR**

DIRECT TESTIMONY

OF

JONATHAN A. LESSER

ON BEHALF OF

FIRSTENERGY SOLUTIONS CORP.

March 21, 2012

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I. INTRODUCTION, PURPOSE, AND SUMMARY OF CONCLUSIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jonathan A. Lesser. I am President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is 6 Real Place, Sandia Park, NM 87047.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A. I am an economist with substantial experience in market analysis in the energy industry. I have over 25 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government entities. I have provided expert testimony before numerous state utility commissions, as well as before the Federal Energy Regulatory Commission ("FERC"), state legislative committees, and international venues.

Before founding Continental Economics, I was a Partner in the Energy Practice with the consulting firm Bates White, LLC. Prior to that, I was the Director of Regulated Planning for the Vermont Department of Public Service. Previously, I was employed as a Senior Managing Economist at Navigant Consulting. Prior to that, I was the Manager, Economic Analysis, for Green Mountain Power Corporation. I also spent seven years as an Energy Policy Specialist with the Washington State Energy Office, and I worked for Idaho Power Corporation and the Pacific Northwest Utilities Conference Committee (an electric industry trade group), where I specialized in electric load and price forecasting.

I hold MA and PhD degrees in economics from the University of Washington and a BS, with honors, in mathematics and economics from the University of New Mexico. My doctoral fields of specialization were applied microeconomics, econometrics and statistics, and industrial organization and antitrust. I am the coauthor of three textbooks, including *Environmental Economics and Policy* (1997), *Fundamentals of Energy Regulation* (2007), and, most recently, *Principles of Utility Corporate Finance* (2011). I have prepared economic impact studies estimating the job effects of electric generating facility construction and operation, and performed studies to examine how jobs are eliminated by uneconomic generation investments. My studies have been published both in peer-reviewed and trade journals. I have attached a copy of my curriculum vitae as Exhibit JAL-1.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the International Association for Energy Economics, the Energy Bar Association, and the Society for Benefit-Cost Analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of FirstEnergy Solutions Corp. ("FirstEnergy Solutions").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO ("PUCO")?

A. Yes. I testified in Case Nos. 08-917-EL-UNC and 08-918-EL-UNC, generally referred to as the "POLR Remand" proceeding, on behalf of the Industrial Energy Users of Ohio. I also testified in Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-

AAM and 11-350-EL-AAM, generally referred to as the "AEP Stipulation" proceeding on behalf of FirstEnergy Solutions Corp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony focuses on Paragraph 2 of the Partial Stipulation between Columbus Southern Power Company and Ohio Power Company (collectively "AEP Ohio") and various other signatory parties. Paragraph 2 states:

> Based on resource planning projections submitted by AEP Ohio pursuant to R.C. 4928.143(B)(2)(c) and the provisions of 4928.64(B)(2) that require AEP Ohio to obtain alternative energy measures including solar resources located in Ohio, the Commission should find that there is a need for the 49.9 MW solar facility known as the Turning Point Solar Project ("Turning Point") during the LTFR planning period as described herein.[1]

Specifically, my testimony demonstrates why the Commission should reject the finding recommended by the Stipulating Parties, and rebuts the testimony submitted by Stipulating Parties' witnesses Castle[2] and Bellamy.[3]

Q. CAN YOU PROVIDE A SUMMARY OF YOUR CONCLUSIONS?

A. Yes. As I discuss in the sections that follow, the Turning Point Solar Project ("Turning Point" or "TPS") does not meet the definition of "need" under the plain language of R.C. 4928.143(B)(2)(c), nor has AEP Ohio demonstrated that, <u>but for</u> its

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1 *In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters*, Case No. 10-501-EL-FOR, et al., Partial Stipulation and Recommendation ("Stipulation", November 21, 2011, Par. 2.

2 *In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters*, Case No. 10-501-EL-FOR, et al., Prefiled testimony of William Castle, March 9, 2012 ("Castle Testimony").

3 *In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters*, Case No. 10-501-EL-FOR, et al., Prefiled testimony of Mark Bellamy, March 9, 2012 ("Bellamy Testimony").

investment in TPS, it cannot meet the state's solar requirements under R.C. 4928.64(B)(2). Indeed, with the Wyandot PPA, AEP Ohio currently has a surplus of in-state solar Renewable Energy Certificates ("solar REC" or "s-RECs").

The plain language of R.C. 4928.64(E) requires that recovery of renewable resource costs developed by an electric distribution utility ("EDU") must be recovered through a bypassable charge. A bypassable charge does not force customers who purchase electricity from competitive retail electric suppliers ("CRES") to pay twice for renewable generation, which would be both anticompetitive and inequitable. However, the Stipulating parties are attempting to conflate a "need" for Turning Point under two completely different statutory requirements—one that serves as a "safety valve" for acquiring retail electric generation resources needed to serve standard service offer ("SSO") customers, and the other for renewable generation needed to satisfy the state's alternative energy requirements. This inappropriate conflation of concepts and statutory requirements is an attempt to justify forcing all AEP Ohio customers, even those who purchase electricity from CRES providers, to pay for Turning Point through a nonbypassable charge.

Imposing a nonbypassable charge to fund Turning Point would be anticompetitive. It would force AEP Ohio customers who purchase electricity from CRES providers to pay twice for solar RECs. This would foreclose market competition and stifle development of the competitive retail electric market in Ohio, contrary to the language in R.C. 4928.02(A)-(D) and (H).

I also rebut the testimony filed by AEP Ohio witness Castle and PUCO Staff witness Bellamy on behalf of the Stipulating parties, who both recommend the PUCO accept the findings in Paragraph 2 of the Stipulation. These witnesses argue that Turning Point is required to meet the requirements for solar RECs, as established under R.C. 4928.64(B)(2). However, these witnesses' arguments are fundamentally flawed. They assume, contrary to existing evidence, that in-state solar development will no longer take place, or will take place in amounts too little to meet in-state s-REC requirements. As a result, they erroneously conclude there will be a "shortage" of s-RECs by the year 2015, which will therefore require a nonbypassable charge for AEP Ohio to develop Turning Point.

II. AEP OHIO HAS NOT ESTABLISHED A "NEED" FOR TURNING POINT AS DEFINED UNDER R.C. 4928.143(B)(2)(C).

Q. WHAT DOES R.C. 4928.143(B)(2)(C) SPECIFICALLY STATE?

A. R.C. 4928.143(B)(2)(c) states that an electric distribution utility's ("EDU") Electric Security Plan may include:

> The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. <u>However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility</u>. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements. (emphasis added).

Q. WHAT IS YOUR UNDERSTANDING OF THE LANGUAGE QUOTED ABOVE?

A. The language of R.C. 4928.143(B)(2)(c) is quite clear. Specifically, it requires a finding of "need" for the generation provided by Turning Point in a resource planning sense, based on projections contained in AEP Ohio's 2010 Long-Term Forecast Report as those projections are submitted by the utility in a proceeding under R.C. 4928.143.[4] The Commission cannot make such a finding here.

Q. ARE YOU FAMILIAR WITH RESOURCE PLANNING CONCEPTS, INCLUDING LOAD FORECASTING?

A. Yes. I began my professional career as a forecaster for Idaho Power Company. I also developed load forecasts while employed at the Pacific Northwest Utilities Conference Committee ("PNUCC"), an industry trade group, where I worked closely with load forecasters at the Northwest Power Planning Council and the Bonneville Power Administration. Furthermore, as Manager, Economic Analysis at Green Mountain Power, I was part of the Resource Planning group, which prepared peak and energy load forecasts, and evaluated resource alternatives to meet those forecasted loads in a least-cost manner. At Green Mountain Power, I also worked with staff at the Electric Power Research Institute ("EPRI") to develop new methodologies to forecast loads at the distribution circuit level and determine least-cost alternatives, and was later presented with an "EPRI Innovators" award for those efforts. As an economic consultant, I have prepared load forecasts and worked with clients on resource planning issues. I have also published articles on new methodologies for resource planning and load forecasting,

[4] AEP Ohio's 2010 Long Term Forecast Report was filed on April 15, 2010 and supplemented on December 20, 2010. *In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters*, Case No. 10-501-EL-FOR, *et al*., "Long-Term Forecast Report to the Public Utilities Commission of Ohio," April 15, 2010 ("2010 LTFR"); "Supplement to the Long-Term Forecast Report to the Public Utilities Commission of Ohio," December 20, 2010 ("2010 LTFR Supplement").

which are listed in the publications section of Exhibit JAL-1. Therefore, I consider myself to be an expert on load forecasting and resource planning issues.

Q. WHAT ARE THE GOALS OF ELECTRIC UTILITY RESOURCE PLANNING?

A. Utility resource planning involves first forecasting future energy and peak loads as accurately as possible, and then ensuring those loads can be met at the lowest expected cost with a portfolio of resources. In other words, the forecasting exercise first establishes whether there is a "need" for new resources–whether generating resources or energy efficiency resources.

Q. BASED ON YOUR EXPERIENCE WITH RESOURCE PLANNING, WHAT DOES THE "NEED" FOR NEW RESOURCES MEAN?

A. Prior to electric utility restructuring, all electric utilities had an obligation to serve. That meant that a utility was required to meet its customers' demand for electricity at all times, which utilities typically did by building generating plants or entering into long-term purchase contracts with other utilities. Therefore, "need" in a resource planning sense related to an electric utility having sufficient electric resources—either generating resources or energy efficiency resources—to meet customer demand at all times, and to ensure that the service provided was reliable. In other words, "need" really meant having enough electricity supplies to ensure the lights would always stay on, including a minimum amount of reserve capacity in case of forced outages. For example, PJM currently requires that all market participants have a minimum installed capacity reserve of just over 15% of their forecast peak load.

After electric utility restructuring, many vertically integrated utilities divested themselves of their generating resources and became EDUs. Customers of these utilities can purchase electricity from CRES providers, and thus the EDUs' obligation is to provide electricity sourced from the wholesale market to those remaining customers who either cannot or will not select an alternative CRES provider. This is the situation in Ohio and refers to SSO customers. Those customers' needs can be met either by auctioning off the right to provide them with electricity, as a number of Ohio EDUs have done, or by serving them with generation owned by the EDU, as is currently the case with AEP Ohio.

Q. ONCE A NEED FOR NEW RESOURCES TO MEET FUTURE DEMAND IS ESTABLISHED, HOW IS A PORTFOLIO OF RESOURCES SELECTED?

A. Once the need for new resources is determined, the resource planning exercise examines all of the available alternatives and selects those which meet that need at the lowest expected cost. The AEP East 2010 Integrated Resource Plan ("IRP") says something quite similar:

> The goal of resource planning for a largely regulated utility such as AEP is to cost-effectively match its energy supply needs with projected customer demand. As such the plan lays out the ***amount***, ***timing*** and ***type*** of resources that achieve this goal at the lowest reasonable cost, considering all the various constraints—reserve margins, emission limitations, renewable and energy efficiency requirements—that are currently mandated or projected to be mandated (emphasis in original).[5]

Q. DOESN'T THAT LANGUAGE YOU HAVE QUOTED FROM AEP EAST'S 2010 IRP MEAN THERE IS A "NEED" FOR RENEWABLE RESOURCES THAT <u>DOES</u> FALL WITHIN THE LANGUAGE OF R.C. 4928.143(B)(2)(C)?

A. No. As I discuss below, renewable resource requirements are set out separately under R.C. 4928.64. The language of R.C. 4928.143(B)(2)(c) has nothing to do with renewable resource requirements.

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[5] AEP East Integrated Resource Plan, Executive Summary, page 1.

Q. HOW DO YOU INTERPRET THE LANGUAGE IN R.C. 4928.143(B)(2)(C) ADDRESSING "NEED"?

A. I interpret the language of R.C. 4928.143(B)(2)(c) as a type of market "safety valve." To understand what this means, we need to consider the market environment in which AEP Ohio operates.

AEP Ohio is a member of PJM, which operates several different types of electricity markets. These markets provide access to both EDUs and CRES providers with the energy and capacity needed to meet customer demand and reserve requirements established by PJM to ensure reliable electric service. Competitive markets work by equating supply and demand. As supply and demand change, so will market prices. For example, as shale gas production has increased, market prices for natural gas have decreased. Not only has that lowered the price of natural gas, it has also reduced the spot market prices of electricity, because the cost of generating electricity with natural gas has decreased. Of course, competitive market conditions can change over time, increasing and decreasing in response to changes in demand and changes in supply. However, competitive markets are also self-correcting. That is, expectations of high market prices lead to increased supplies, which reduce prices, and vice-versa.

Under R.C. 4928.143(B)(2)(c), the benefits of a generating resource must flow through to an EDU's Ohio customers. An EDU cannot levy a nonbypassable surcharge on its customers to build a generating resource, sell all of the energy and capacity into the market, and keep the profits for its shareholders. That is why R.C. 4928.143(B)(2)(c) also states that "the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility."

Q, WOULD ALLOWING AN EDU TO BUILD GENERATING RESOURCES THAT ARE NOT "LEAST-COST" AND THEN LEVY NONBYPASSABLE SURCHARGES FOR THOSE RESOURCES MAKE ECONOMIC SENSE?

A, No. First, in any resource planning context, it does not make economic sense to build a resource that is not least-cost. For example, if two gas-fired generation alternatives, A and B, are identical in every respect, except that A has an overall cost of $100/MWh and B has an overall cost of $75/MWh, then it would not make economic sense to build A.

Similarly, forcing EDU customers—including customers who purchase electricity from CRES providers (who are already responsible for the alternative energy needs of their customers)—to pay a nonbypassable surcharge for an above-market cost resource makes no economic sense. The reason is that it would force all customers to pay above-market costs when there are lower-cost alternatives in the market. Moreover, forcing customers to pay above-market costs for electricity, including customers who either purchase electricity from CRES providers or wish to purchase from CRES providers, would stifle market competition. The reason is that it would require those customers to pay twice for generation—first through the nonbypassable surcharge and second through the price charged by the CRES provider.

Q. CAN YOU SUMMARIZE THE ANALYSIS THAT AN EDU WOULD NEED TO PERFORM UNDER R.C. 4928.143(B)(2)(C) TO JUSTIFY A NONBYPASSABLE SURCHARGE?

A. Yes. There are three analytical steps an EDU would need to perform to justify a nonbypassable surcharge. These are:

<u>Step 1:</u> Forecast future SSO customer energy and peak demand.

Step 2: Show that based on the forecast of energy and peak demand, additional resources will need to be acquired.

Step 3: Show that the expected future market prices of energy and capacity to meet that demand are higher than an identified least-cost alternative resource or portfolio of generating demand response and energy efficiency resources.

A fourth step would be to ensure that, if the EDU develops any "least-cost" resources selected under Step 3, that its ratepayers are protected from unexpected and imprudent cost increases that negate the "least-cost" aspect of the resource.

A. AEP Ohio Has Failed to Perform Step 1 Accurately and Does Not Meet the Requirement of Step 2

Q. HAS AEP OHIO MET STEP 1, FORECASTING ITS FUTURE ENERGY AND CAPACITY REQUIREMENTS?

A. Yes, but not accurately. AEP Ohio has submitted its LTFR, which does provide a long-term peak and energy forecast. However, AEP Ohio's forecast of the amount of retail shopping load is far too low. It thus overstates its SSO retail load and, hence, AEP Ohio's need for resources to serve SSO customers.

Q. CAN YOU EXPLAIN WHY AEP OHIO'S FORECAST OF THE AMOUNT OF SHOPPING LOAD TOO LOW?

A. Yes. Exhibit 1 of Supplemental Appendix 1 to the 2010 LFTR Supplement is AEP Ohio's energy sales forecast. The bottommost table on Exhibit 1 shows that AEP Ohio expects retail shopping loads to be between 9% and 12% of total retail loads at the meter. For example, AEP Ohio forecast total shopping load in 2012 to be 4,441 GWh

("Ohio Choice") and total SSO metered load to be 43,511 GWh.[6] Thus, total metered load, including both Ohio Choice and SSO loads, is 43,511 + 4,441 = 47,952 GWh. The percentage of that total that is shopping load is thus 4,441 / 47.952 = 9.3%. By 2020, the shopping percentage is forecast to increase to 11.3% (5,345 GWh Ohio Choice / (5,345 + 41,921) GWh metered load).

In contrast, an Affidavit submitted by AEP Ohio's William Allen on March 5, 2012 states:

> As of March 1, 2012, the data indicates that 26.1% of the Ohio Power's connected load has switched to an alternative supplier with another 2.2% with a pending switch. An additional 8.4% of the load served by Ohio Power has provided notice to the company of their intent to switch to an alternate supplier. That means customers representing 36.7% of the Company's load have switched or indicated their intent to switch.[7]

The 36.7% actual and pending retail shopping load as of March 1, 2012 is almost four times larger than the 9.3% retail shopping load AEP Ohio projected in the 2010 LTFR Supplement filed on December 20, 2010. Thus, AEP Ohio overestimated its SSO load in the 2010 LTFR Supplement and failed to correct this overestimate in the testimony of AEP Ohio witness Castle filed on March 9, 2012.

Q. HAS AEP OHIO PRESENTED ANY ESTIMATES OF HOW ITS SSO LOADS MIGHT CHANGE?

A. Yes. In that same affidavit, Mr. Allen presented the results of a financial analysis associated with forcing AEP Ohio to charge the PJM market price of capacity. Mr. Allen's analysis assumed that customer switching to CRES providers would increase,

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6 The AEP Ohio LTFR values are reproduced, along with the calculated shopping percentages, in Exhibit JAL-4, Table A.

7 *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC, Affidavit of William Allen, March 5, 2012 ("Allen Affidavit)," par. 5.

such that "65% of load for residential customers, 80% of load for commercial customers and 90% of load for industrial customers (excluding a single large customer) by the end of 2012,"[8] would have switched. If Mr. Allen's analysis is correct, then AEP Ohio's in-state solar REC requirement would decrease commensurately, while CRES providers' in-state solar REC requirements would increase commensurately. With these lower SSO loads, AEP Ohio would not need to purchase any additional in-state solar RECs.

Q. IS THE FACT THAT ACTUAL RETAIL SHOPPING LOAD IS ALMOST FOUR TIMES GREATER THAN WHAT AEP OHIO PREDICTED IN THE 2010 LTFR SUPPLEMENT IMPORTANT?

A. Yes. It is important because the magnitude of AEP Ohio's in-state solar REC requirement is based on its SSO retail load. The higher the level of retail shopping, the fewer the quantity of solar RECs AEP Ohio requires. In fact, as I discuss in Section III, AEP has surplus in-state solar RECs.

Q. HAS AEP OHIO MET STEP 2 BY SHOWING THAT THERE IS A NEED FOR NEW GENERATING OR EFFICIENCY RESOURCES TO MEET ITS PROJECTED PEAK AND ENERGY LOADS IN A RESOURCE PLANNING SENSE?

A. No. According to AEP Ohio's own figures, as published in its 2011 LTFR Report, the Company's net capability of its generating assets well exceeds its peak load both now and into the foreseeable future.[9] This is illustrated in Figure 1 and includes both generator retirements and additional renewable resources, including Turning Point.

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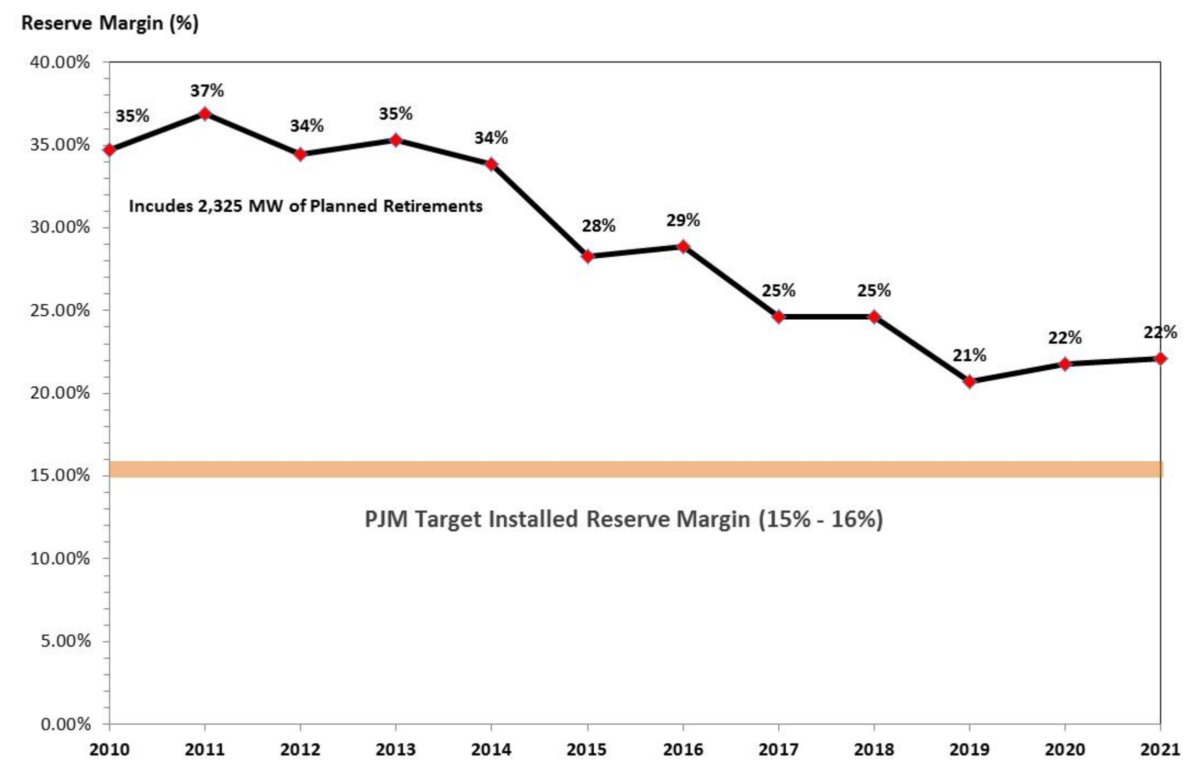
8 *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company,* Case No. 10-2929-EL-UNC, Affidavit of William Allen, March 5, 2012, par. 9.

9 AEP Ohio Filing, PUCO Case Nos. 11-2501-EL-FOR and 11-2502-EL-FOR, 4/15/2011 ("2011 LTFR Report"), pp. 140-141.

Figure 1: AEP Ohio Reserve Margin (2010 – 2021)



Source: AEP Filing, PUCO Case Nos. 11-2501-EL-FOR and 11-2502-EL-FOR, 4/15/2011, pp. 140-141. Retirements include Conesville 3 (165 MW, 2012), Muskingum River 2&4 (395 MW, 2012), Muskingum River 1&3 (380 MW, 2014), Muskingum River 5 (600 MW, 2015), Picway 5 (95 MW, 2017), Sporn 2, 4 (290 MW, 2017), Kammer 1-3 (400 MW, 2019), . Available Capability is net of an average of 1.0 GW in annual net sales over the 2008-2016 period. PJM's Target IRM is known through PY15/16. Scaled to reflect coincidence with PJM 2010 Summer Peak.

As Figure 1 shows, even with 2,325 MW of planned retirements, AEP Ohio's available capacity remains far above the PJM installed reserve margin ("PJM IRM").[10]

Q. WILL NEW EPA REGULATIONS TO REDUCE MERCURY EMISSIONS, WHICH WERE ADOPTED IN DECEMBER 2011, AFFECT AEP OHIO'S RESERVE MARGIN?

A. Yes. In a news release dated June 9, 2011, AEP Corporation ("AEP") listed its (then) current plans to comply with the new EPA rules, which were issued in December 2011.[11] This news release listed the coal-fired power plants that AEP stated it would

[10] 2011 LTFR Report, pp. 138-139.

[11] http://www.aep.com/environmental/news/?id=1697. Attached as Exhibit JAL-2.

permanently retire, as well as plants where AEP would retire some of the units, but continue to operate and/or retrofit others.

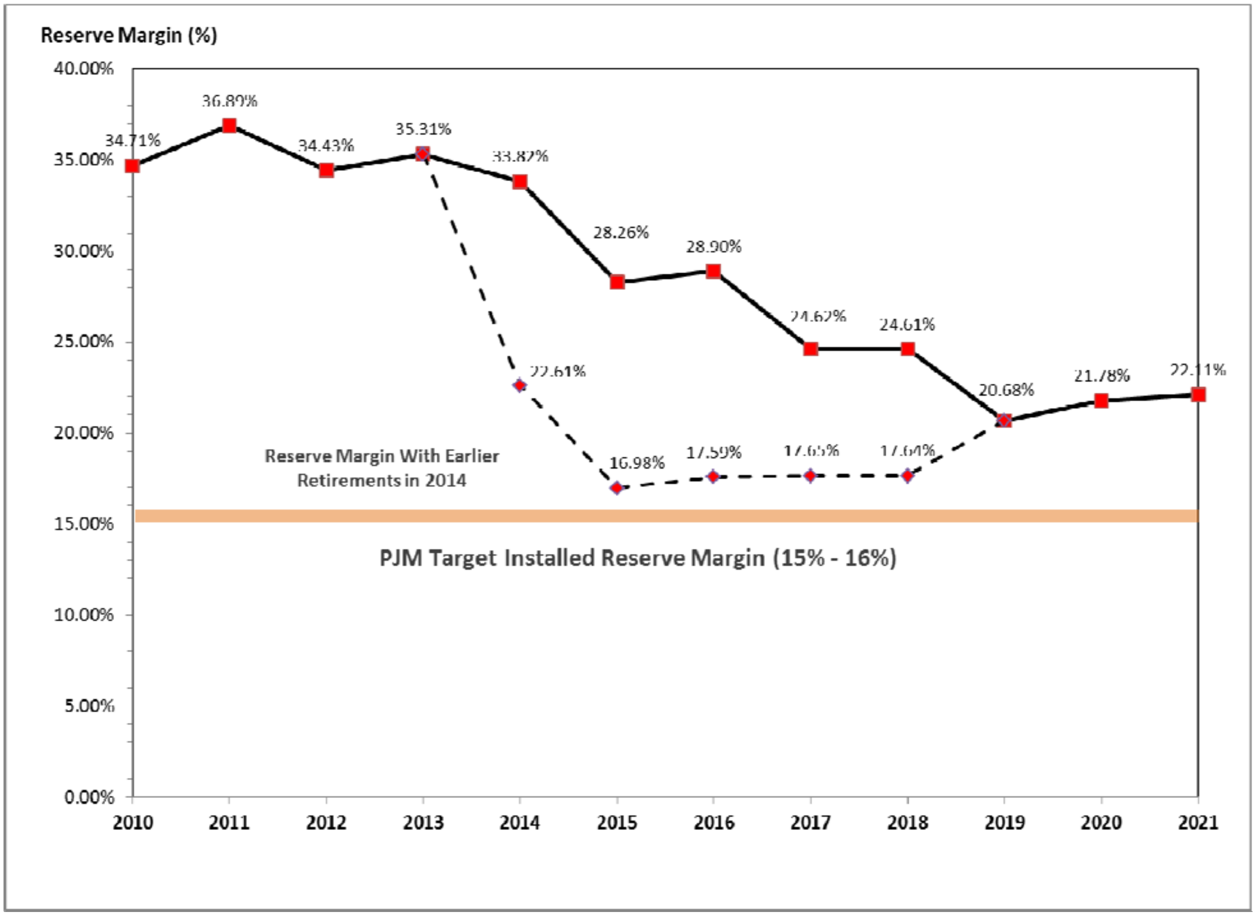
Q. DOES THE NEWS RELEASE INCLUDE RETIREMENTS THAT ARE ALREADY REFLECTED IN AEP OHIO'S 2011 LTRF?

A. Yes. I compared the plants listed in the news release with those shown on pp. 136-139 of the 2011 LTFR. The news release shows that AEP Ohio would accelerate retirement of Philip Sporn Units 2 and 4 from the Summer 2017 date shown on page 139 of the 2011 LTFR to 2014, accelerate retirement of the Picway 5 Unit from Summer 2017 to 2014, and accelerate retirement of the Kammer Plant from Summer 2019 to 2014. Other units listed for retirement on the news release will either be retired at the times shown in the 2011 LTFR or are not AEP Ohio generating plants.

Q. HOW DO THESE EARLIER PLANT RETIREMENTS AFFECT AEP OHIO'S RESERVE MARGIN?

A. The impact of the accelerated plant retirements is shown on Figure 2.

Figure 2: AEP Ohio Reserve Margin with Accelerated Retirements Due to EPA Regulations (2010 – 2021)



As Figure 2 shows, even with accelerated retirements stemming from the EPA regulations, AEP Ohio's reserve margin will still be above PJM targets. Again, therefore, AEP Ohio has no "need" for new generating capacity in a resource planning sense.

Q. DO FIGURES 1 AND 2 ACCOUNT FOR ANY PLANNED MAJOR CAPACITY ADDITIONS, SUCH AS REPOWERING MUSKINGUM RIVER 5?

A. No. Figures 1 and 2 do not include any new gas-fired generating capacity, even though AEP has discussed adding such capacity as part of its overall generating strategy. For example, AEP completed construction of the 580 MW Dresden gas-fired power plant, located in Dresden, Ohio, and that plant went on-line on February 1, 2012.[12] The press release previously attached as Exhibit JAL-2 also discusses repowering of Muskingum River 5 with natural gas, adding 510 MW of capacity.

Figures 1 and 2 include 1,050 MW of wind generation purchased power contracts added in amounts of between 100 MW and 150 MW per year. They also include the 49 MW of Turning Point and an additional 64 MW of solar PV added in the years 2019 – 2021. Because PJM applies a 38% summer capacity derating factor to solar PV capacity, the additional summer capacity supplied by Turning Point would only be 19.0 MW (0.38 x 49.9 MW = 19.0 MW).[13] Given that AEP Ohio's overall generating capacity is over 12,000 MW, the 19 MW of capacity provided by Turning Point has a negligible impact on AEP Ohio's total capacity.

Q. ARE THE STIPULATING PARTIES ARGUING THERE IS A NEED FOR TURNING POINT CONSISTENT WITH THE "NEED" LANGUAGE OF R.C. 4928.143(B)(2)(C) AND "NEED" IN THE SENSE OF RESOURCE PLANNING STEP 2?

A. No. According to the 2010 LTFR Supplement,[14] AEP Ohio is <u>not</u> developing Turning Point to meet its overall need for generation, in contrast to the plain language of R.C. 4928.143(B)(2)(c). Instead, the stipulating parties wish to portray AEP Ohio meeting its solar energy requirement under R.C. 4928.64(B) as <u>identical</u> to a "need" for new generating capacity under R.C. 4928.143(B)(2)(c). As I discuss in the next section,

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[12] "AEP Increases Natural Gas-Fired Generation Capacity As Newly Constructed Dresden Plant Goes On Line," February 1, 2012. http://www.aep.com/newsroom/newsreleases/?id=1741

[13] PJM, "2014/2015 RPM Base Residual Auction Results," p.11. http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx. PJM will hold the 2015/2016 Base Residual Auction in May of 2012.

[14] *See* 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 5.

this definition of "need" is completely flawed because it is at odds with the plain language of R.C. 4928.143(B)(2)(c).

B. <u>The Stipulating Parties Have Not Demonstrated that Turning Point is a "Least-Cost" Resource, or Even a Least-Cost Solar Resource, and thus Fail Step 3.</u>

Q. WITH REGARD TO TURNING POINT, WHAT WOULD THE STIPULATING PARTIES HAVE TO SHOW UNDER STEP 3 OF THE RESOURCE PLANNING EXERCISE?

A. The Stipulating Parties would have to show that Turning Point is a least-cost resource with a below-market cost. However, I am not aware of anyone who is arguing that solar PV is a "least-cost" generating resource in the resource planning sense.

Q. HAVE THE STIPULATING PARTIES SHOWN THAT TURNING POINT IS THE LEAST-COST IN-STATE SOLAR RESOURCE AVAILABLE?

A. No. And this goes back to the common-sense aspect of resource planning I discussed previously, using the example of two gas-fired generating plants, A and B. If A and B are otherwise identical, but B is less costly than A, then B is the preferred, "least-cost" resource. Similarly, if an EDU can obtain in-state solar RECs at a cost of (say) $300/REC or at a cost of $400/REC, then it would not make economic sense for the EDU to purchase the higher-cost RECs. As many advertisements ask, "Why pay more?"

AEP Ohio, however, has presented absolutely no evidence demonstrating that Turning Point is the least-cost source of in-state solar RECs. In fact, the Stipulating Parties have presented no evidence in this proceeding as to Turning Point's costs. Instead, as I discuss in Section IV, AEP Ohio witness Castle <u>assumes</u> no other in-state solar RECs will ever become available without providing any evidence whatsoever supporting this assumption. In essence, that unsupported assumption allows him to erroneously conclude that Turning Point is "least-cost" by default: if resource A is the only available choice, then it must be least-cost.

Q. CONSISTENT WITH THE COMMISSION'S LANGUAGE IN ITS DECEMBER 14, 2011 ORDER,[15] HAVE THE STIPULATING PARTIES SHOWN THAT IN-STATE SOLAR RECS CANNOT BE OTHERWISE OBTAINED THROUGH THE COMPETITIVE MARKET?

A. No. The Stipulating Parties have offered no evidence whatsoever that in-state solar RECs cannot be otherwise obtained through the competitive market. The December 14, 2011 Commission Order held that AEP Ohio must "demonstrate that the Turning Point project is necessary to comply with the solar renewable energy resource provisions contained in Section 4928.64, Revised Code, and that sufficient solar energy resources are not available through competitive markets." Rather than attempting to show that solar energy resources would not be available through competitive markets, as the Commission's Order required, the Stipulating Parties have assumed that sufficient in-state solar RECs cannot be obtained in the competitive market without supporting that assumption in any way.

Q. HOW COULD THE STIPULATING PARTIES SHOW THAT IN-STATE SOLAR RECS CANNOT BE OBTAINED THROUGH THE COMPETITIVE MARKET?

A. There are two ways to demonstrate that in-state solar RECs cannot be obtained through the competitive market. First, the Stipulating Parties would have to show that AEP Ohio has attempted to obtain in-state solar RECs using competitive market tools and that these attempts have failed. In other words, they must show that the competitive

[15] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan,* Case No. 11-346-SSO, et al., Order, December 14, 2011, page 40 (emphasis added).

market today cannot provide the needed in-state solar RECs. Second, the Stipulating Parties also would have to demonstrate that the competitive market is simply incapable of bringing forth sufficient in-state solar RECs in the future. In other words, they must show that a competitive market for in-state solar RECs will not develop in the foreseeable future.

Q. WHAT COMPETITIVE MARKET TOOLS COULD AEP OHIO USE TO DETERMINE WHETHER THERE ARE SUFFICIENT SOLAR RECS AVAILABLE IN THE MARKET?

A. The most obvious way to determine whether sufficient solar RECs—both in-state and total—can be obtained in the market would be through a competitive solicitation, such as the solicitations that have been conducted by the FirstEnergy EDUs. In 2011, for example, the FirstEnergy EDUs conducted a competitive solicitation for in-state solar RECs over a 10-year period. This multi-year period provided much greater revenue certainty to solar developers, and thus reduced investment uncertainty. According to a press release issued by FirstEnergy (attached as Exhibit JAL-3), FirstEnergy requested 5,000 solar RECs and received proposals for more than twice that amount:

> "The robust participation in this RFP is evidence of a maturing renewable energy credit market throughout Ohio," says Dennis Chack, President of Ohio operations for FirstEnergy. "There were 28 qualified bids received, offering more than two times the required number of SRECs and over four times the required number of RECs, and many of the credits are originating in Toledo, Cleveland and other cities in our service area."[16]

This solicitation, which was conducted in October of 2011, clearly elicited a significant response from the competitive market.

[16] "FirstEnergy's Ohio Utilities Meet Compliance Benchmarks Through Request for Renewable Energy Credits," November 7, 2011. https://www.firstenergycorp.com/newsroom/news_releases/firstenergy_s_ohioutilitiesmeetcompliancebenchmarksthroughreques.html

Q. HAVE THE FIRSTENERGY UTILITIES HELD ANY ADDITIONAL COMPETITIVE SOLICITATIONS FOR IN-STATE SOLAR RECS?

A. Yes. On January 30, 2012, the FirstEnergy EDUs issued another request for proposals ("RFP") for 1,000 solar RECs each year for ten years. Responses to this RFP were received on March 7, 2012, and results are expected on March 29, 2012.

Q. DO YOU KNOW IF AEP OHIO HAS PREVIOUSLY ISSUED ANY SORT OF COMPETITIVE SOLICITATION FOR IN-STATE SOLAR RECS?

A. Yes. It's my understanding that AEP Ohio issued an RFP for in-state solar RECs in 2009. In contrast to the FirstEnergy EDUs' 10-year RFP, the AEP Ohio RFP was to supply in-state solar RECs for 2009 only.

Q. HAS AEP OHIO ISSUED ANY RFPS FOR IN-STATE SOLAR RECS IN THE SAME QUANTITY THAT TURNING POINT WOULD PROVIDE?

A. To my knowledge, AEP Ohio has not issued any such RFP.

Q. GIVEN THAT AEP OHIO HAS NOT ATTEMPTED TO ISSUE ANY OTHER COMPETITIVE SOLICITATIONS FOR SOLAR RECS SINCE 2009, HAVE THE STIPULATING PARTIES ADEQUATELY DEMONSTRATED THAT COMPETITIVE MARKETS CANNOT PROVIDE THE IN-STATE SOLAR RECS THAT AEP OHIO MUST OBTAIN UNDER R.C. 4928.64(B)?

A. No. Ignoring the fact that AEP Ohio has overestimated its solar REC requirement by assuming retail shopping levels that are far below actual shopping to-date, there is no evidence that AEP Ohio is attempting to obtain in-state solar RECs from the competitive market. Moreover, as I discuss in Section IV, the arguments presented by Stipulating Parties' witnesses Castle and Bellamy regarding the inability of competitive market forces to provide sufficient in-state solar RECs are fundamentally flawed and contradicted by evidence.

Q. HAS AEP OHIO ACQUIRED ANY IN-STATE SOLAR RECS UNDER LONG-TERM CONTRACTS?

A. Yes. AEP Ohio signed a 20-year purchase power agreement ("PPA") with the Wyandot Solar Facility. Under that agreement, AEP Ohio currently receives 15,130 in-state solar RECs per year.[17]

Q. DID AEP OHIO IMPOSE A NONBYPASSABLE SURCHARGE FOR THE POWER PURCHASE AGREEMENT WITH THE WYANDOT SOLAR FACILITY?

A. No. AEP Ohio has not requested a nonbypassable surcharge for the power purchase agreement with Wyandot.

Q WHAT ARE YOUR OVERALL CONCLUSIONS REGARDING AEP OHIO'S "NEED" FOR TURNING POINT UNDER R.C. 4928.143(B)(2)(C)?

A. First, under the plain language of R.C. 4928.143(B)(2)(c), AEP Ohio has no "need" for any new generating resources, because its installed reserve margin will remain above PJM required levels through 2021, even taking account of announced generating plant retirements to comply with new EPA regulations.

Second, even if AEP Ohio could demonstrate a need for new resources, acquiring Turning Point would not be a "least-cost" acquisition that would be obtained at a below-market cost, as required under the "safety valve" aspect of R.C. 4928.143(B)(2)(c).

Third, the load forecast presented by AEP Ohio in the 2010 LTFR Supplement assumes retail shopping levels that rise only to 11.3% of total metered load by 2020, yet on March 5, 2012, AEP Ohio submitted an affidavit by William Allen stating that retail shopping loads are already almost 37%.

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[17] *See* 2010 LTFR Supplement, Supplemental Appendix 3. Because solar PV panels degrade slowly over time, the quantity of RECs will also decrease slightly over time.

Fourth, AEP Ohio has not attempted to determine whether the competitive market can supply the in-state solar RECs it needs at a lower cost than Turning Point, despite the success of recent competitive solicitations by FirstEnergy distribution utilities.

Fifth, even if, arguendo, AEP Ohio could demonstrate that Turning Point is the least-cost source of in-state solar RECs, there is no justification for imposing a nonbypassable charge on its distribution customers. Not only have other utilities, including the FirstEnergy utilities, acquired solar RECs in the market and not attempted to levy resulting nonbypassable charges on distribution customers, but AEP Ohio itself has previously acquired in-state solar RECs, notably the 15,130 in-state solar RECs per year provided by the Wyandot Solar Facility, without imposing a nonbypassable charge.

III. THE STIPULATING PARTIES ARGUMENTS FOR A NONBYPASSABLE CHARGE FOR TURNING POINT UNDER R.C. 4928.143(B)(2)(c) ARE FLAWED

Q. WHAT IS THE BASIS FOR THE STIPULATING PARTIES' "NEED" ARGUMENT UNDER R.C. 4928.143(B)(2)(C)?

A. The Stipulating Parties have attempted to conflate the "need" or "safety valve" language in R.C. 4928.143(B)(2)(c) with the renewable energy requirements of R.C. 4928.64(B)(2). The Stipulating Parties are not arguing that solar PV is a "least-cost" resource. Indeed, if solar PV were a "least-cost" resource in the resource planning sense, there would be no need for Ohio or any other state to establish a solar REC statutory requirement, because generation developers would have an incentive to build solar PV resources to meet PJM customers' electric needs based on the wholesale price of electricity.

Because it is impossible to show that Turning Point is a least-cost resource relative to the PJM market, the project is clearly not "needed" in the resource planning sense set forth in R.C. 4928.143(B)(2)(c). Thus, the Stipulating Parties argue that Turning Point is "needed" for AEP Ohio to comply with the in-state solar REC requirements under R.C. 4928.64(B)(2) and, hence, AEP Ohio should be allowed to impose a nonbypassable surcharge on its customers to meet that "need."

Q. WHAT ISSUES DOES R.C. 4928.64 ADDRESS?

A. R.C. 4928.64 sets out "alternative energy resource" requirements. Specifically, R.C. 4928.64(B) sets out an annual schedule for the quantities of renewable energy resources, including solar energy resources,[18] that all load serving entities—both EDUs and CRES providers—must have in proportion to their overall electric energy sales to their retail customers.

Q. WHAT DOES R.C. 4928.64(E) STATE REGARDING CHARGES FOR RENEWABLE ENERGY RESOURCES?

A. R.C. 4928.64(E) states that

> All costs incurred by an electric distribution utility in complying with the requirements of this section <u>shall be</u> <u>bypassable</u> by any consumer that has exercised choice of supplier under section 4928.03 of the Revised Code (emphasis added).

The plain language of Section R.C. 4928.64(E) is that an EDU cannot impose a non-bypassable surcharge to comply with the renewable energy requirements set forth in R.C. 4928.64(B). That is why the Stipulating Parties are attempting to redefine "need" under R.C. 4928.143(B)(2)(c) as referring to renewable energy resources, including solar PV.

[18] Solar can also include solar thermal generation plants, but in practice, but I am not aware of any solar thermal plants providing s-RECs to Ohio EDUs and CRES providers.

If they are successful, then AEP Ohio can impose a nonbypassable charge for Turning Point, contrary to the plain language of R.C. 4928.64(E).

Q. WHY IS IMPOSING A NONBYPASSABLE SURCHARGE FOR TURNING POINT PROBLEMATIC?

A. A nonbypassable surcharge imposes a tax on all AEP Ohio customers, including those who purchase electricity from CRES providers. This is problematic for the following reasons.

First, imposing a nonbypassable charge for a renewable generating resource directly contradicts the plain language of R.C. 4928.64(E) quoted above.

Second, imposing such a charge is anticompetitive, because it forces customers who take power from CRES providers to pay twice for in-state solar RECs. This forecloses market competition because rational customers will not want to pay twice for the same thing.

Third, such a tax would be contrary to Ohio policy that seeks to encourage development of a fully competitive retail electric market. By forcing CRES customers to pay twice, it would retard development of a fully competitive retail electric market.

Fourth, by foreclosing retail market competition, imposing a nonbypassable surcharge ironically would increase AEP Ohio's need for future solar RECs by increasing its forecast SSO loads. Thus, if AEP Ohio is allowed to impose a nonbypassable charge for Turning Point, shopping loads may be reduced, meaning that AEP Ohio's solar REC requirement would increase. That, in turn, would make it more likely AEP Ohio would seek to impose nonbypassable charges for other in-state solar PV resources in the future when they, too, are "needed."

Q. COULD AEP OHIO IMPOSE A BYPASSABLE SURCHARGE TO PAY FOR THE TURNING POINT PROJECT?

A. Yes. Under the terms of ESP I, AEP Ohio recovers all renewable energy costs through the Fuel Adjustment Clause ("FAC").[19] In the ESP II proceedings, AEP Ohio proposed to split the costs of Renewable Energy Purchase Agreements ("REPAs") into their REC and non-REC components.[20] The REC component would be recovered through the bypassable Alternative Energy Rider and the non-REC portion would be recovered through the Fuel Adjustment Clause.[21] Based on AEP Ohio's own testimony and current practice, AEP Ohio can clearly impose a bypassable surcharge to pay for the Turning Point project. Other than unsupported claims, AEP Ohio has never demonstrated that it cannot go forward with TPS on a bypassable basis in the same way it has with Wyandot. However, AEP Ohio could <u>not</u> impose that bypassable surcharge on customers who were purchasing electricity directly from CRES providers.

Q. HAS AEP OHIO DEMONSTRATED THAT TURNING POINT IS PRUDENT?

A. No. Because AEP Ohio has not attempted to obtain in-state solar RECs from the competitive market since 2009, it has no reference point with which to compare the cost of Turning Point.[22] Instead, as shown in Exhibit 5 of Supplemental Appendix 1 of the 2010 LTFR Supplement, AEP Ohio only provided an analysis based on revenue requirements for generic solar resources.

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[19] *See* Case No. 11-346 *et al.*, Testimony of Philip J. Nelson filed January 27, 2011, pp. 4-7.

[20] *Id*., p. 7.

[21] *Id*.

[22] Indeed, even this foray into the market is not directly comparable to the Turning Point proposal, since the Turning Point proposal involves guaranteed recovery for several years while the 2009 solicitation was for only a single year.

Q. DO YOU CONSIDER THE ANALYSIS SHOWN IN THAT EXHIBIT TO EVIDENCE THAT TURNING POINT IS PRUDENT?

A. No. AEP Ohio states that Exhibit 5 in Supplemental Exhibit 1 offers the results of a comparative analysis between the imputed value of s-RECs and the value of s-RECs available in the market.[23] Yet this is not what Exhibit 5 shows. The exhibit provides only an estimate of the cost of constructing "generic" solar resources. AEP Ohio makes no attempt to show that construction of those generic resources (let alone Turning Point) is a lower-cost option as compared to purchasing s-RECs. Instead, AEP Ohio has chosen to argue that s-RECs will not be available at all.

Q. WHY WOULD IMPOSING A NONBYPASSABLE SURCHARGE FOR TURNING POINT BE ANTICOMPETITIVE?

A. Imposing a nonbypassable surcharge to pay for Turning Point would be anticompetitive because CRES providers are also required to comply with the renewable energy requirements set forth in R.C. 4928.64(B)(2). Therefore, if a nonbypassable surcharge is imposed on AEP Ohio customers, then customers who purchase their electricity from CRES providers would be forced to pay twice for renewable energy. They would be forced to pay for the Turning Point project costs <u>and</u> the costs of s-RECs purchased by their CRES provider. Forcing CRES customers to pay <u>twice</u> for in-state solar RECs, while AEP Ohio's ESP customers only pay a diluted price for Turning Point, harms those customers who have elected to shop and places CRES suppliers at an obvious competitive disadvantage, thus foreclosing competition. It would impose a barrier to entry in the form of an "entrance fee" for CRES suppliers to compete in the

[23] 2010 LTFR Supplement, p. 9 of 14.

market, penalize existing CRES customers for shopping, and act as a disincentive to existing ESP customers choosing CRES providers. That is clearly anticompetitive.

Q. WHY WOULD IMPOSING A NONBYPASSABLE SURCHARGE FOR TURNING POINT BE CONTRARY TO ESTABLISHED STATE POLICY TO DEVELOP COMPETITIVE RETAIL ELECTRIC MARKETS?

A. Because imposing a nonbypassable surcharge for Turning Point would penalize customers who wish to purchase electricity from CRES providers, such a charge would inhibit retail electric competition. That would be contrary to the plain language of R.C. 4928.02(A)-(D), and (H).

CRES providers already produce or procure all requisite energy, capacity and renewables to serve their retail customers. Forcing all AEP Ohio customers, including those who purchase electricity from CRES providers, to pay for Turning Point would be discriminatory and contrary to the language of R.C. 4928.02(A). It would restrict "the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs," contrary to the language of R.C. 4928.02(B). It would reduce the diversity of electric suppliers, contrary to the language of R.C. 4928.02(C). It would discourage market access, contrary to the language of R.C. 4928.02(D). And, by forcing CRES customers to pay twice for in-state solar RECs, once through the nonbypassable surcharge and again for the in-state solar RECs purchased or developed by their CRES provider, it would restrict effective competition in the provision of retail electric service, contrary to the language of R.C. 4928.02(H).

A. The Stipulating Parties Do Not Estimate AEP Ohio's Need for In-State Solar RECs Accurately

Q. DO EITHER OF THE STIPULATING PARTIES' WITNESSES DISCUSS AEP OHIO'S IN-STATE SOLAR REC REQUIREMENTS?

A. Mr. Castle does, but only as an aside. He states that AEP Ohio's total solar requirement will be approximately 131 GWh in the year 2020.[24] However, as I discuss below, this estimate assumes far lower retail shopping levels than AEP Ohio is already experiencing. Mr. Bellamy does not discuss AEP Ohio's need for solar RECs at all. Moreover, whereas Mr. Castle does mention AEP Ohio's overall solar REC requirement, his testimony focuses solely on overall state requirements.

AEP Ohio calculated its total solar obligation in the 2010 LTFR Supplement at Exhibit 2 of Supplemental Appendix 1. For 2012, AEP Ohio shows a total solar REC obligation of 24.95 GWh or 24,950 MWh, incorrectly based on a retail shopping level of 9.3% of its load. Of that total, at least one-half, or 12,475 GWh, must be in-state solar RECs.

Q. WHY IS FOCUSING ON THE STATE SOLAR REC REQUIREMENT INAPPROPRIATE?

A. The Stipulating Parties are attempting to justify a nonbypassable charge for AEP Ohio, so it can obtain needed in-state solar RECs, based on simplistic and erroneous state-level analysis. They never address how CRES providers and other EDUs are obtaining these RECs. Nor do they ever address any other steps AEP Ohio has taken to obtain in-state solar RECs. Instead, the Stipulating Parties present the nonbypassable

[24] Castle Testimony, p. 9, lines 1-4,

charge for Turning Point as a *fait accompli* based on total in-state solar REC requirements, rather than AEP Ohio's in-state solar REC requirements.

Q. HAS THE DATE WHEN ADDITIONAL IN-STATE SOLAR RECS ARE NEEDED CHANGED?

A. Yes. As AEP Ohio witness Castle notes, "the need for additional in-state solar generation has shifted from 2012 to 2015 accounting for the solar generation certified in the state since December of 2010 and using the PUCO estimate of annual benchmarks, which are 10-20 percent lower than the basis used in the 2010 LTFR Supplement analysis."[25]

The 2010 LTFR Supplement also assumed no new solar PV developed after December 8, 2010, as shown on Figure 1, page 10, which is reproduced on page 8 of Mr. Castle's testimony. Figure 1 also shows that AEP Ohio calculated the total in-state solar REC requirement based on an assumption of 160,000 MWh of state load. And, as shown on Table 1, page 9 of the 2010 LTFR supplement, as of December 8, 2010, there were a total of 22,680 MWh of in-state solar RECs.

Q. WAS ANY NEW IN-STATE SOLAR PV DEVELOPED IN 2011?

A. Yes. As Stipulating Parties witness Bellamy notes, "There were 20.84 MWs of certified in-state solar capacity built in 201l," including the 9.8 MW facility built by BNB Napoleon LLC. A 2 MW solar PV facility built by the City of Bryan, Ohio, came on-line on January 23, 2012.[26]

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[25] Castle Testimony, p. 10, lines 3-6.

[26] Bellamy Testimony, p. 4, lines 9-14.

Q. IS THERE ANY REASON TO BELIEVE THAT NO NEW SOLAR DEVELOPMENT WILL TAKE PLACE IN 2012 OR THEREAFTER?

A. No. In fact, the Stipulating Parties never explain why Turning Point itself would not be developed, but for a nonbypassable surcharge. For example, they provide no evidence as to why the developers of Turning Point could not sign a long-term PPA with AEP Ohio, as AEP Ohio did with Wyandot, and have AEP Ohio recover the cost of the RECs provided through its bypassable Alternative Energy Rider.

Q. WITH THE LOWER PUCO SOLAR BENCHMARKS AND NEW IN-STATE SOLAR DEVELOPMENT, IS THERE STILL A NEED FOR IN-STATE SOLAR RECS IN 2012?

A. No. As Mr. Castle states, "the need for additional in-state solar generation has shifted from 2012 to 2015 accounting for the solar generation certified in the state since December of 2010 and using the PUCO estimate of annual benchmarks, which are 10-20 percent lower than the basis used in the 2010 LTFR Supplement analysis."[27] In fact, with the Wyandot PPA, AEP Ohio currently has surplus in-state solar RECs**.**

Q. DOES EXHIBIT 2 OF SUPPLEMENTAL APPENDIX 1 IN THE 2010 LTFR SUPPLEMENT ACCURATELY FORECAST AEP OHIO'S NEED FOR SOLAR RECS?

A. No. For the year 2020 Exhibit 2 of Supplemental Appendix 1 shows a total solar REC requirement for AEP Ohio of just over 131,000 solar RECs, which implies an in-state requirement of half that amount, or 65,500 solar RECs. However, this greatly overestimates AEP Ohio's need for in-state solar RECs because it assumes far lower rates of retail shopping than have already occurred. As I discussed previously, the 2010 LTFR

[27] Castle Testimony, p. 10, lines 3-6.

Supplement (Appendix, Exhibit 2) assumes shopping levels that are between 9.3% and 11.3% over the years 2012 – 2020. That is why AEP Ohio projects its 131,000 solar RECs total and 65,500 in-state solar REC requirements in the year 2020.

However, in the Affidavit filed by AEP Ohio witness Allen on March 5, 2012, Mr. Allen states that actual and pending shopping load as of March 1, 2012 was 36.7% of total load, about four times larger than AEP Ohio's shopping assumption in the 2010 LTFR Supplement. Even if one assumes no additional retail switching by AEP SSO customers after March 1, 2012, that is, even if the percentage of shopping load remains at 36.7% through 2020, AEP Ohio's in-state solar REC requirement would fall to about 44,700 solar RECs. These calculations are shown in Exhibit JAL-4.

Q. IS IT REASONABLE TO ASSUME THAT THERE WILL BE NO MORE ACTUAL OR PENDING RETAIL SWITCHING AFTER MARCH 1, 2012?

A. No. Especially given the decrease in PJM wholesale market energy prices, in large measure because of low natural gas prices, it is reasonable to assume more AEP Ohio customers will switch to CRES providers. For example, according to the PUCO's "Summary of Switch Rates from EDUs to CRES Providers in Terms of Sales for the Month Ending December 31, 2011," switch rates for EDUs ranged between 51% (Dayton Power and Light) to 84% (Cleveland Electric). Based on these data, it would be unreasonable to assume that, of all the Ohio EDUs, only AEP Ohio will not experience any additional switching.

Q. HAS AEP OHIO ITSELF ASSUMED HIGHER SWITCHING RATES FOR ANY OTHER PURPOSE?

A. Yes. Mr. Allen's March 5, 2012 Affidavit discusses an assumption that, owing to rejection of the Stipulation, AEP was assuming that customer switching would increase to 65% of residential customer load, 80% of commercial customer load, and 90% of industrial customer load by the end of 2012, and remaining at that level throughout 2013.[28] This equates to an overall shopping load of about 79%, based on AEP Ohio's forecast of residential, commercial, and industrial sales. As shown in Exhibit JAL-5, this implies an overall in-state solar REC requirement for AEP Ohio of less than 10,000 solar RECs in 2020. In that case, AEP Ohio has no need for any additional in-state solar RECs at all, given that it has a 20-year power purchase agreement with the Wyandot solar facility, which began commercial operation in May 2010, is now providing it over 15,000 in-state solar RECs.[29]

Q. WHAT DO YOU CONCLUDE ABOUT THE STIPULATING PARTIES CONFLATING THE "NEED" FOR TURNING POINT BASED ON THE REQUIREMENTS OF R.C. 4928.143(B)(2)(C) WITH THE RENEWABLE ENERGY REQUIREMENTS UNDER R.C. 4928.64?

A. First, as I discussed previously, Turning Point does not meet the "need" requirement under R.C. 4928.143(B)(2)(c), because AEP Ohio has no need for new generation and, even if it did, Turning Point is clearly not a below-market, least-cost resource.

Second, the Stipulating Parties have overestimated AEP Ohio's in-state solar REC requirement, because they have assumed retail shopping levels that are only one-fourth as much as has already taken place, as the Affidavit of Mr. Allen makes clear. Moreover, should shopping levels increase even further, which is likely, AEP Ohio's in-state solar

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28 Allen Affidavit, Par 9(g).

29 *See In the Matter of the 2009 Annual Filing of Columbus Southern Power Company and Ohio Power Company Required by Rule 4901:1-35-10, Ohio Administrative Code*, Case No. 10-1261-EL-UNC, Direct Testimony of Joseph Hamrock, September 1, 2010, page 23, lines 16-21.

REC requirement will drop even further. In fact, under Mr. Allen's assumption of 79% of total load shopping, AEP Ohio has no need for any new in-state solar resources at all through 2020.

Third, imposing a nonbypassable surcharge for Turning Point would be anticompetitive, unduly discriminatory, and conflict with the policy goals set forth in R.C. 4928.02.

Fourth, the Stipulating Parties provide no evidence that in-state solar PV will no longer be developed. Nor do they demonstrate why the developers of Turning Point would be unwilling to sign a long-term PPA with AEP Ohio, whose costs would be recovered through either the bypassable Fuel Adjustment Clause or the bypassable Alternative Energy Rider.

IV. REBUTTAL OF STIPULATING PARTIES' WITNESSES CASTLE AND BELLAMY

Q. CAN YOU SUMMARIZE THE ARGUMENTS MADE BY STIPULATING PARTIES' WITNESS CASTLE REGARDING WHY THE PUCO SHOULD APPROVE A NONBYPASSABLE CHARGE FOR THE TURNING POINT PROJECT?

A. Yes. Mr. Castle presents a completely static argument, as shown on the chart on page 8 of his testimony. Specifically, Mr. Castle assumes there will be no solar PV development whatsoever after 2012 and, based on that assumption, determines that there will be a shortage of in-state solar RECs by the year 2015 and thereafter. (Again, this is three years later than the "shortage" date assumed in AEP Ohio's 2010 LTFR Supplement.) As a result of this "shortage," Mr. Castle concludes that AEP Ohio should be allowed to impose a nonbypassable surcharge for the development of Turning Point, which would provide sufficient in-state solar RECs through the year 2019.[30]

Q. DOES MR. CASTLE HAVE ANY OTHER ARGUMENTS IN SUPPORT OF A NONBYPASSABLE CHARGE FOR THE TPS PROJECT?

A. Yes. Mr. Castle states:

> The analysis included in the 2010 LTFR Supplement shows that as of December 2010, solar generation that met the criteria required by the PUCO was in an amount roughly sufficient to satisfy state-wide requirements in 2011. Thus, all or most s-RECs generated by the capacity that was in-place would be consumed leaving a need for additional solar capacity to come on-line in 2011 in order to satisfy 2012 (and future) benchmarks.[31]

Mr. Castle's argument can be summarized as follows. First, the total in-state solar REC requirement will increase annually through the year 2025. That is certainly true. Second, if we assume that no new solar PV is built in Ohio, then the in-state solar REC requirement will not be met. That is also true. Three, Turning Point is "needed" and a nonbypassable surcharge should be imposed on all AEP Ohio customers to pay for it. It is Mr. Castle's logical "leap" from point two to point three that is problematic.

Q. WHY IS MR. CASTLE'S ARGUMENT PROBLEMATIC?

A. Mr. Castle's argument suffers from both logical and factual flaws.

Q. CAN YOU EXPLAIN THE LOGICAL FLAWS IN MR. CASTLE'S ARGUMENT?

A. Yes. Mr. Castle's assumption applies a static argument to a dynamic condition. In other words, he argues that, because Turning Point is the only known in-state solar project at this time, it must be built if the state is to meet its in-state solar REC goals

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30 Castle Testimony, p. 11, line 1.

31 Castle Testimony, p. 6, lines 16-21.

through the year 2025. Such logic is equivalent to arguing that, because the decommissioning fund for a new nuclear power plant is not fully funded on its first day of service, the fund is "deficient" and the entire decommissioning fund must be collected up front.

Mr. Castle has constructed a "strawman" argument, which he then proceeds to knock down. By assuming that no additional in-state solar will be approved and developed for the next 12 years, he is able to show that even with Turning Point there will still be an in-state s-REC "shortage" beginning in the year 2015.

The obvious fault with Mr. Castle's argument is that he offers no explanation as to the basis for his assumption of no additional solar PV development after March 5, 2012, but for Turning Point. In other words, Mr. Castle assumes that the PUCO will never again receive, or approve, any in-state solar PV applications. In light of the solar PV development that has already taken place in Ohio, this argument makes no factual sense.

Q. HAVE SOLAR PV APPLICATIONS TO THE PUCO DECLINED OR EVEN STOPPED ALTOGETHER?

A. No. As shown in the table below, the PUCO data shows a rapid increase in the number of in-state solar PV applications that have been approved by the PUCO since 2009.

Year	Ohio MW	Applications Approved
2009	13.41	14
2010	6.71	152
2011	22.20	342
2012 1/	3.46	109
TOTAL	**45.79**	**617**

1/ Through 2/27/2012. Source: PUCO Ohio Website, "Approved Facilities Report," March 10, 2012.

As this table shows, the number of approved in-state solar PV applications has grown steadily, from 14 in 2009 to 342 in 2011. In just the first two months of 2012, the PUCO approved 109 applications. If that rate holds constant, the number of approved applications in all of 2012 will be in excess of 600. Yet, despite this rapid increase in solar PV activity within Ohio, to justify his "need" argument for Turning Point, Mr. Castle assumes, without explanation, that all such activity will stop, and there will be no further solar PV applications made. His assumption has no basis and defies logic.

Q. DID AEP OHIO ALSO ASSUME THERE WOULD BE NO NEW SOLAR PV DEVELOPED BETWEEN 2012 AND 2020 IN ITS IRP?

A. No. Exhibit 2 to Mr. Castle's testimony is a copy of the AEP-East 2010 Integrated Resource Plan ("IRP"). As shown on Page 59 of that IRP (attached as Exhibit JAL-6), AEP assumed there would be 227 MW of solar PV developed between the years 2012 and 2020, and available to it to satisfy the company's internal goal of "10% of System energy (total East and West zones) from renewable resources by 2020."

Q. ARE YOU AWARE OF ANY OTHER PLANNED SOLAR PV FACILITIES FOR OHIO?

A. Yes. Exhibit JAL-7 shows that there are 215 MW of new, in-state solar PV facilities currently in the PJM generation queue, including the 60 MW for Turning Point.[32] These are in addition to the facilities that have been approved by the PUCO.

Q. ARE ALL RESOURCES IN THE PJM GENERATION QUEUE EVENTUALLY DEVELOPED?

A. No. There is no "guarantee" that all of the resources shown in Exhibit JAL-7 will be built. However, developers do not enter into the PJM generation queue lightly, because there are significant costs associated with completing the required interconnection studies. Thus, although not all of these resources may be developed, it is unreasonable to assume that none of them will be developed (except Turning Point), nor that any other solar PV resources will be developed to justify a nonbypassable charge for Turning Point.

Q. CAN YOU SUMMARIZE THE ARGUMENTS MADE BY STIPULATING PARTIES' WITNESS BELLAMY REGARDING WHY THE PUCO SHOULD APPROVE A NONBYPASSABLE CHARGE FOR THE TPS PROJECT?

A. Yes. Unlike Mr. Castle, Mr. Bellamy assumes there will be some future growth in the amount of in-state solar PV resources.

Mr. Bellamy presents four alternative scenarios with additions of between 8 MW and 20 MW of solar PV annually through the year 2025, both with and without the addition of the TPS project in 2015. Based on these projects, Mr. Bellamy concludes that, "[O]f the four scenarios analyzed, only the two scenarios which assume the addition

[32] The factor used to convert direct current (DC) capacity to alternating current (AC) capacity is 0.85. Thus, Turning Point's 60 MW of DC is equivalent to about 50 MW AC.

of a 10-12 MW facility annually have enough in-state solar MWs to achieve compliance through the term of the analysis."[33] Although Mr. Bellamy never creates a projection with 10-12 MW of solar PV added each year, it appears he determined that amount of new capacity annually is needed to meet Ohio's in-state solar REC requirement. Thus, whereas Mr. Bellamy recognizes that 20.04 MW of in-state solar PV was built in 2010 and 20.84 MW was built in 2011, he nevertheless constructs his 8 MW per year scenario because it "represents the amount added in 2010 and 2011 without the large 12 MW, 9.792 MW, and 2 MW facilities."[34] Using that 8 MW per year forecast, Mr. Bellamy concludes there will be too few in-state solar resources developed, which he argues justifies the "need" for Turning Point. [35]

Q. IS MR. BELLAMY'S EXCLUSION OF THE "LARGE" FACILITIES THAT HAVE ACCOUNTED FOR OVER 12 OF THE 20 MW OF SOLAR PV BUILT IN 2010 AND 2011 REASONABLE?

A. No. Because of economies of scale, it is more likely that developers will build larger solar facilities: with a lower installed cost per kW, developers can make more money. Furthermore, Mr. Bellamy offers no reasons why, if 20 MW of in-state solar PV was developed in 2010 and 2012, that only 40% of that quantity is likely to be developed from 2012 onward, especially given the presence of large solar PV resources in the PJM queue.

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[33] Bellamy Testimony, p. 7, lines 6-8.

[34] *Id.*, p. 5, lines 1-2. According to Mr. Bellamy, the 2 MW facility came on-line on January 23, 2012.

[35] *Id.*, p. 9, lines 4-14.

Q. DOES MR. BELLAMY DISCUSS ANY SPECIFIC SOLAR PV RESOURCES UNDER DEVELOPMENT IN OHIO?

A. No. He states that, "PUCO Staff is not aware of any other solar PV being developed in the state at this time."[36] However, as I previously discussed, there are numerous projects under development, and the PUCO has approved increasing numbers of applications each year. Moreover, there are a number of Ohio solar PV projects in the PJM generation queue.

Q. DO YOU AGREE WITH MR. BELLAMY'S PROJECTIONS REGARDING OUT OF STATE SOLAR CAPACITY FROM PENNSYLVANIA?

A. No. Mr. Bellamy believes that the termination of the Pennsylvania "sunshine" may limit out-of-state solar capacity in the future.[37] However, the data from Pennsylvania refutes this position. The PJM queue for Pennsylvania, attached as Exhibit JAL-8, shows 36 projects currently pending at a total of 194 MW, which suggests that the expiration of the sunshine program is not having the impact that Mr. Bellamy suggests.

Q. HAVE EITHER OF THESE TWO WITNESSES PROVIDED REASONABLE JUSTIFICATION FOR IMPOSING A NONBYPASSABLE SURCHARGE ON AEP OHIO CUSTOMERS?

A. No. Their arguments are unrealistic, simplistic, and at odds with observed facts.

First, AEP Ohio has grossly overestimated its own in-state solar REC requirement by assuming retail shopping loads will only be one-fourth as much as the current shopping load, as discussed in Mr. Allen's affidavit.

Second, Mr. Castle's assumption of no future solar PV development, except Turning Point, and Turning Point only if AEP Ohio can levy a nonbypassable charge, is

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[36] *Id*., p.3, lines 16-18.

[37] Bellamy Testimony, pp. 8-9.

unreasonable and unsupported. Mr. Bellamy's assumption that there will be an average of 8 MW of in-state solar PV development each year is more reasonable than an assumption of zero growth. However, Mr. Bellamy's 8 MW estimate does not anticipate future construction of large facilities and fails to incorporate any of the solar resources listed in the PJM queue into his analysis. Mr. Bellamy's 8 MW estimate is therefore unreasonable.

Third, the Stipulating Parties offer no evidence as to why AEP Ohio could not enter into a long-term PPA with Turning Point, similar to the long-term PPA AEP Ohio previously entered into with the Wyandot Solar Facility, and recoup the cost of the in-state solar RECs through its bypassable FAC (or the proposed Alternative Energy Rider in ESP II), as it now recoups the cost of the RECs supplied by Wyandot.

Finally, both witnesses wrongly conflate the definition of "need" under R.C. 4928.143(B)(2)(C) with the in-state renewable requirements under R.C 4928.64(B)(2). Their testimony is contrary to the clear position established by the PUCO in its December 14, 2011 Order regarding the Partial Stipulation, because AEP Ohio has provided no evidence that it attempted to secure in-state solar RECs using competitive methods, such as the FirstEnergy utilities did in their recent competitive solicitations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of Jonathan A. Lesser On Behalf Of FirstEnergy Solutions Corp.* was served this 21st day of March, 2012, via e-mail upon the parties below.

/s/ *N. Trevor Alexander*
One of the Attorneys for FirstEnergy Solutions Corp.

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Jonathan A. Lesser, Ph.D.

President

SUMMARY OF EXPERIENCE

Dr. Jonathan Lesser is the President of Continental Economics, Inc., and has over 25 years of experience working for regulated utilities, governments, and as an economic consultant. He has extensive experience in valuation and damages analysis, from estimating the damages associated with breaking commercial leases to valuing nuclear power plants. Dr. Lesser has performed due diligence studies for investment banks, testified on generating plant stranded costs, assessed damages in commercial litigation cases, and performed statistical analysis for class certification. He has also served as an arbiter in commercial damages proceedings.

He has analyzed economic and regulatory issues affecting the energy industry, including cost-benefit analysis of transmission, generation, and distribution investment, gas and electric utility structure and operations, generating asset valuation under uncertainty, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, cost of capital, depreciation, risk management, incentive regulation, economic impact studies of energy infrastructure development, and general regulatory policy.

Dr. Lesser has prepared expert testimony and reports in cases before utility commissions in numerous U.S. states; before the Federal Energy Regulatory Commission (FERC); before international regulators in Latin America and the Caribbean; in commercial litigation cases; and before legislative committees in Connecticut, Maryland, New Jersey, Ohio, Texas, Vermont, and Washington State. He has also served as an independent arbiter in disputes involving regulatory treatment of utilities and valuation of energy generation assets.

Dr. Lesser is the author of numerous academic and trade press articles. He is also the coauthor of *Environmental Economics and Policy*, published in 1997 by Addison Wesley Longman, *Fundamentals of Energy Regulation*, published in 2007 by Public Utilities Reports, Inc., and *Principles of Utility Corporate Finance*, published in 2011 by Public Utilities Reports, Inc. Dr. Lesser is also a contributing columnist and Editorial Board member for *Natural Gas & Electricity*.

AREAS OF EXPERTISE

- State, federal, and international rate regulation – cost of capital, depreciation, cost of service, cost allocation, rate design, incentive regulation, and regulatory framework design
- Commercial damages estimation and litigation
- Cost-benefit analysis
- Regulatory policy and market design
- Economic impact analysis and input-output studies
- Environmental compliance and litigation
- Market power analysis
- Load forecasting and energy market modeling
- Energy asset valuation and due diligence

SELECTED EXPERT TESTIMONY AND REPORTS

Suiza Dairy

- U.S. District Court, District of Puerto Rico, Civil Case No. 04-1840. (*Vacqueria Tres Monjitas and Suiza Dairy, Inc. v. Jose O. Laboy, in his Official capacity, as the Secretary of the Department of Agriculture for the Commonwealth of Puerto Rico, and Juan R. Pedro-Gordian, in his official capacity, as Administrator of the Office of the Milk Industry Regulatory Administration for the Commonwealth of Puerto Rico*)

Subject: Addition of a "country risk" premium for the fresh milk dairy industry in the Commonwealth of Puerto Rico

Southwestern Electric Cooperative

- FERC proceeding regarding wholesale distribution rate application of Ameren Illinois (*Re: Midwestern ISO and Ameren Illinois*, Docket No. ER11-2777-002, et al.)

Subject: Allowed rate of return and capital structure

Exelon Corporation

- Proceeding before the New Jersey Board of Public Utilities (Docket No. EO-11050309)

Subject: PJM Capacity Market, Capacity Procurement, and Transmission Planning

FirstEnergy Solutions Corp.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO)

  Subject: AEP Ohio energy security plan, benefits of retail market competition.

Industrial Energy Users of Ohio

- Proceeding before the Ohio Public Utilities Commission (Case No. 08-917-EL-SSO)

  Subject: Determination of cost associated with "provider-of-last-resort" (POLR) service and AEP Ohio's use of option pricing models.

Southwest Gas Corporation

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP10-1398-000)

  Subject: Development of risk-sharing methodology for unsubscribed and discount capacity costs.

Portland Natural Gas Shippers

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP10-729-000)

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP08-306-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Independent Power Producers of New York

- FERC proceeding (New York Independent System Operator, Inc., Docket No. ER11-2224-000)

Subject: Reasonableness of the proposed installed capacity demand curves and cost of new entry values proposed by the New York Independent System Operator.

Maryland Public Service Commission

- Merger application of FirstEnergy Corporation and Allegheny Energy, Inc. (I/M/O FirstEnergy Corp and Allegheny Energy, Inc., Case No. 9233)

  Subject: Proposed merger between FirstEnergy Corporation and Allegheny Energy. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power and merger synergies.

Alliance to Protect Nantucket Sound

- Proceeding before the Massachusetts Department of Public Utilities (Case No. D.P.U. 10-54)

  Subject: Approval of Proposed Long-Term Contracts for Renewable Energy With Cape Wind Associates, LLC.

Brookfield Energy Marketing, LLC

- FERC proceeding (*New England Power Generators Association, et al. v. ISO New England, Inc.,* Docket Nos. ER10-787-000, ER10-50-000, and EL10-57-000 (consolidated)).

  Subject: Proposed forward capacity market payments for imported capacity into ISO-NE.

Public Service Company of New Mexico

- Proceeding before the New Mexico Public Regulation Commission (Case No. 10-00086-UT)

  Subject: Load forecast for future test year, residential price elasticity study.

M-S-R Public Power Agency

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER09-187-000 and ER10-160-000)

Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

Financial Marketers

- FERC proceeding (*Black Oak Energy, LLC v PJM Interconnection, L.L.C.*, Docket No. EL08-014-002)

  Subject: Allocation of surplus transmission line losses under the PJM tariff.

Southwest Gas Corporation and Salt River Project

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP08-426-000)

  Subject: Analysis of proposed capital structure and recommended capital structure adjustments

New York Regional Interconnect, Inc.

- Proceeding before the New York Public Service Commission (Case No. 06-T-0650)

  Subject: Analysis of economic and public policy benefits of a proposed high-voltage transmission line.

Occidental Chemical Corporation

- FERC Proceeding (*Westar Energy, Inc.* ER07-1344-000)

  Subject: Compliance of wholesale power sales agreement with FERC standards

EPIC Merchant Energy, LLC, et al.

- FERC Proceeding (*Ameren Services Company v. Midwest Independent System Operator, Inc.,* Docket Nos. EL07-86-000, EL07-88-000, EL07-92-000 (Consolidated)

Subject: Allocation of revenue sufficiency guarantee costs.

Cottonwood Energy, LP

- Proceeding before the Public Utility Commission of Texas (*Application of Kelson Transmission Company, LLC for a Certificate of Convenience and Necessity for the Amended Proposed Canal to Deweyville 345 kV Transmission Line with Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, and Orange Counties*, Docket No. 34611, SOAH Docket No. 473-08-3341)

  Subject: Benefits of transmission capacity investments.

Redbud Energy, LP

- Proceeding before the Oklahoma Corporation Commission (*Request of Public Service Company of Oklahoma for the Oklahoma Corporation Commission to Retain an Independent Evaluator,* Cause No. PUD 200700418)

  Subject: Reasonableness of PSO's 2008 RFP design.

The NRG Companies

- FERC Proceeding (*ISO New England Inc. and New England Power Pool,* Docket No. ER08-1209-000)

  Subject: Compensation of Rejected De-list Bids Under ISO-NE's Forward Capacity Market Design

Dynegy Power Marketing, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages accruing to Dynegy arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in NYISO during the summer of 2002.

Constellation Energy Group

- FERC proceeding (*Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC*, Docket No. EL08-67-000)

  Subject: "Just and reasonableness" of PJM's Reliability Pricing Mechanism.

Government of Belize, Public Utility Commission

- Proceeding before the Belize Public Utility Commission, *In the Matter of the Public Utilities Commission Initial Decision in the 2008 Annual Review Proceeding for Belize Electricity Limited*.

  Subject: Arbitration and Independent Expert's report, in dispute between the Belize PUC and Belize Electricity Limited in an annual electric rate tariff review, as required under Belize law.

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

  Subject: Analysis of proposal to revise RTO capacity market design developed by the American Forest and Paper Association.

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.*, Case No. EO-2008-0046.

  Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

  Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Rate of return for an electric distribution company

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

  Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc*., Docket Nos. ER07-169-000 and ER07-170-000)
- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate rate of return for regulated milk processors in the Commonwealth of Puerto Rico.

DPL Inc.

- Proceeding before the Ohio Board of Tax Appeals (*DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio*, Case No. 2004-A-1437)

  Subject: Economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation

- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.

- Maryland Public Service Commission (Case No. 9063)

  Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of benefits of restructuring since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate rate of return for the natural gas pipeline industry.

BP Canada Marketing Corp.

- FERC proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER09-1521-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER08-1318-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER07-1213-000)

Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER06-1325-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

  Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc*., Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
  - Concurrent proceedings: *Re: Green Mountain Power Corp*., Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of service regulation, as well as under a proposed alternative regulation proposal.
  - *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy

to analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.

- *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC proceeding regarding the rate application of Northern Natural Gas Company (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- Arkansas Public Service Commission rate proceedings
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

  Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC rate proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.

- *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

  Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

COMMERCIAL LITIGATION EXPERIENCE

- *Lorali, Ltd., et al. v. Sempra Energy Solutions, LLC, et al*. Damages associated with abrogation of retail electric supply contract.
- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use for estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.
- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital insurance claims.
- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.
- *Lyubner v. Sizzling Platters, Inc.*. Performed an econometric analysis of damage claims based on sales impacts associated with advertising.
- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.
- *Nat'l. Association of Electric Manufacturers v. Sorrell.* Testified on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

ARBITRATION CASES

***TransCanada Hydro Northeast, Inc. v. Town of Littleton, New Hampshire*, (CPR File No. G-09-24).**

Subject: dispute regarding valuation for property tax purposes of a hydroelectric facility located on the Connecticut River.

Served as neutral on a three-person arbitration panel.

***Belize Electricity Limited v. Belize Public Utilities Commission* (Claim No. 512 of 2008)**.

Subject: Proceeding before the Supreme Court of Belize alleging that the Final Decision by the Belize Public Utilities Commission setting electric rates and tariffs for the 2008-2009 period were unreasonable and non-compensatory.

Prepared independent report on behalf of the Belize Supreme Court for arbitration of the dispute.

SELECTED BUSINESS CONSULTING EXPERIENCE

- For the COMPETE Coalition, prepared report on how electric competition creates economic growth.
- For an industry group, developed econometric model of the impacts of shale gas production on U.S. natural gas prices.
- For an environmental advocacy group, critically evaluated the financial implications of operating restrictions for an off-shore wind generating facility stemming from requirements under the U.S. Endangered Species Act.
- For a major investor-owned utility in the US, prepared a new system of short-term peak and energy forecasting models.
- For a major wholesale electric generation company, prepared comprehensive economic impact studies for use in FERC hydroelectric relicensing proceedings.
- For a major investor-owned utility in the Southwest US, prepared a detailed econometric model and wrote a comprehensive report on residential price elasticity that was required by regulators.
- For a major investor-owned utility in the Southwest US, developed a methodology to value nuclear plant leases that incorporated future uncertainty regarding greenhouse gas regulations.

- Faculty member, PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, 2008 – 2009. Courses taught:
    - Sector Issues: Basic Techniques–Energy
    - Sector Issues in Rate Design: Energy
    - Sector Issues in Rate Design: Energy–Case Studies
    - Transmission Pricing Issues
- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.
- For industrial customers in the State of Vermont, prepared a position paper on the impacts of demand side management funding on electric rates and competitiveness.
- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For electric utilities undergoing restructuring, developed comprehensive economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a major nuclear plant owner and operator in the U.S., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.

- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For a major nuclear plant owner and operator, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.
- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.
- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

EDUCATION

- PhD, Economics, University of Washington
- MA, Economics, University of Washington
- BSc, Mathematics and Economics (with honors), University of New Mexico

EMPLOYMENT HISTORY

- 2009–Present: Continental Economics, Inc., President.
- 2004–2009: Bates White, LLC, Partner, Energy Practice.
- 2003–2004: Vermont Dept. of Public Service, Director of Planning.
- 1998–2003: Navigant Consulting, Senior Managing Economist.
- 1996–1998: Adjunct Lecturer, School of Business, University of Vermont.
- 1993–1998: Green Mountain Power Corporation, Manager, Economic Analysis.

- 1990–1993: Adjunct Lecturer, Dept. of Business and Economics, Saint Martin's College.
- 1986–1993: Washington State Energy Office, Energy Policy Specialist.
- 1984–1986: Pacific Northwest Utilities Conference Committee, Energy Economist.
- 1983–1984: Idaho Power Corporation, Load Forecasting Analyst.

PROFESSIONAL ACTIVITIES

- Reviewer, *Energy*
- Reviewer, *The Energy Journal*
- Reviewer*, Energy Policy*
- Reviewer, *Journal of Regulatory Economics*

PROFESSIONAL ASSOCIATIONS

- Energy Bar Association
- International Association for Energy Economics
- Society for Benefit-Cost Analysis

PUBLICATIONS

Peer-reviewed journal articles

- Lesser, J., "Gresham's Law of Green Energy," *Regulation*, Winter 2010-2011, pp. 12-18.
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- Lesser, J., "Centralized vs. Decentralized Resource Acquisition: Implications for Bidding Strategies." *Public Utilities Fortnightly* (June 1990).
- Lesser, J., "Most Value—The Right Measure for the Wrong Market?" *The Electricity Journal* 2 (December 1989): 47–51.

Selected speaking engagements

- "Competitive Energy Markets: How are they Working?" Constellation Executive Energy Forum, November 2, 2011.
- "The Failures of Transmission Planning and Policy," Harvard Electric Policy Group, February 25, 2010.
- "Financing the Smart Grid," Energy Bar Association Seminar, Washington, DC, December 4, 2009.

- "Renewable Power: At the Crossroads of Economics and Policy," Presentation to the Utilities State Government Organization, Newport, Rhode Island, July 13, 2009.
- "The Stimulus Act and Laws they Didn't Teach You in Law School," presentation to the 27th National Regulatory Conference, Williamsburg, VA, May 19, 2009.
- "Rate Recovery for Capital Intensive Generation: Rate Base and Construction Work in Progress," Law Seminars International, Las Vegas, NV, February 5, 2009.
- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.
- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.
- "Energy and the Environment." Vermont Journal of Environmental Law, South Royalton, VT, March 10, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

Print

AEP Shares Plan For Compliance With Proposed EPA Regulations

Company advocates for more time and flexibility to reduce the negative impact of the proposed EPA rules on customers, jobs and the economy

COLUMBUS, Ohio, June 9, 2011 – American Electric Power (NYSE: AEP) today announced the company's plan for complying with a series of regulations proposed by the U.S. Environmental Protection Agency (EPA) that would impact coal-fueled power plants. Based on the regulations as proposed, AEP's compliance plan would retire nearly 6,000 megawatts (MW) of coal-fueled power generation; upgrade or install new advanced emissions reduction equipment on another 10,100 MW; refuel 1,070 MW of coal generation as 932 MW of natural gas capacity; and build 1,220 MW of natural gas-fueled generation. The cost of AEP's compliance plan could range from $6 billion to $8 billion in capital investment through the end of the decade. High demand for labor and materials due to a constrained compliance time frame could drive actual costs higher than these estimates. The plan, including retirements, could change significantly depending on the final form of the EPA regulations and regulatory approvals from state commissions.

The retirements and retrofits in the plan are in addition to more than $7.2 billion that AEP has invested since 1990 to reduce emissions from its coal-fueled generation fleet. Annual emissions of nitrogen oxides from AEP plants are 80 percent lower today than in 1990. Sulfur dioxide emissions from AEP plants are 73 percent lower than in 1990. The company currently owns nearly 25,000 MW of coal-fueled generation, approximately 65 percent of its total generating capacity. Coal would fuel approximately 57 percent of AEP's total generating capacity by the end of the decade.

"We support regulations that achieve long-term environmental benefits while protecting customers, the economy and the reliability of the electric grid, but the cumulative impacts of the EPA's current regulatory path have been vastly underestimated, particularly in Midwest states dependent on coal to fuel their economies. We have worked for months to develop a compliance plan that will mitigate the impact of these rules for our customers and preserve jobs, but because of the unrealistic compliance timelines in the EPA proposals, we will have to prematurely shut down nearly 25 percent of our current coal-fueled generating capacity, cut hundreds of good power plant jobs, and invest billions of dollars in capital to retire, retrofit and replace coal-fueled power plants. The sudden increase in electricity rates and impacts on state economies will be significant at a time when people and states are still struggling," said Michael G. Morris, AEP chairman and chief executive officer.

Although some jobs would be created from the installation of emissions reduction equipment, AEP expects a net loss of approximately 600 power plant jobs with annual wages totaling approximately $40 million as a result of compliance with the proposed EPA rules.

"We are deeply concerned about the impact of the proposed regulations on our customers and local economies. Communities that have depended on these plants to provide good jobs and support local services will face significant reductions in payroll and property taxes in a very short period of time. The economic impact will extend far beyond direct employment at power plants as thousands of ancillary jobs are supported by every coal-fueled generating unit. Businesses that have benefited from reasonably priced coal-fueled power will face the impact of electricity price increases ranging from 10 percent to more than 35 percent just for compliance with these environmental rules at a time when they are still trying to recover from the economic downturn," Morris said.

"Although discounted by some, the potential impacts on the reliability of the transmission system, particularly in the Midwest, are significant. The proposed timelines for compliance aren't adequate for construction of significant retrofits or replacement generation, so many coal-fueled plants would be prematurely retired or idled in just a few years. AEP's compliance plan alone would abruptly cut generation capacity in the Midwest by more than 5,400 MW. Depending on the year, another 1,500 MW to 5,200 MW of AEP generation would be idled or curtailed for extended periods as pollution control equipment is installed," Morris said.

AEP has shared its compliance plan with PJM Interconnection, Southwest Power Pool and North American Electric Reliability Corp. for use in their evaluation of the impacts of EPA's proposed rules.

"We will continue to work through the EPA process with the hope that the agency will recognize the cumulative impact of the proposed rules and develop a more reasonable compliance schedule. We also will continue talking with lawmakers in Washington about a legislative approach that would achieve the same long-term environmental goals with less negative impact on jobs and the U.S. economy," Morris said. "With more time and flexibility, we will get to the same level of emission reductions, but it will cost our customers less and will prevent premature job losses, extend the construction job benefits, and ensure the ongoing reliability of the electric system."

AEP's current plan for compliance with the rules as proposed includes permanently retiring the following coal-fueled power plants:

- Glen Lyn Plant, Glen Lyn, Va. – 335 MW (retired by Dec. 31, 2014);
- Kammer Plant, Moundsville, W.Va. – 630 MW (retired by Dec. 31, 2014);
- Kanawha River Plant, Glasgow, W.Va. – 400 MW (retired by Dec. 31, 2014);
- Phillip Sporn Plant, New Haven, W.Va. – 1,050 MW (450 MW expected to retire in 2011, 600 MW retired by Dec. 31, 2014); and
- Picway Plant, Lockbourne, Ohio – 100 MW (retired by Dec. 31, 2014).

AEP would retire generating units at the following locations but continue operating some generation at the sites:

- Big Sandy Plant, Louisa, Ky. – Units 1 and 2 (1,078 MW) retired by Dec. 31, 2014;
  Big Sandy Unit 1 would be rebuilt as a 640-MW natural gas plant by Dec. 31, 2015;
- Clinch River Plant, Cleveland, Va. – Unit 3 (235 MW) retired by Dec. 31, 2014; Units 1 and 2 (470 MW total) would be refueled with natural gas with a capacity of 422 MW by Dec. 31, 2014;
- Conesville Plant, Conesville, Ohio – Unit 3 (165 MW) retired by Dec. 31, 2012; Units 5 and 6 (800 MW total) would continue operating with retrofits;
- Muskingum River Plant, Beverly, Ohio – Units 1-4 (840 MW) retired by Dec. 31, 2014; Muskingum River Unit 5 (600 MW) may be refueled with natural gas with a capacity of 510 MW by Dec. 31, 2014, depending on regulatory treatment in Ohio;
- Tanners Creek Plant, Lawrenceburg, Ind. – Units 1, 2 and 3 (495 MW) retired by Dec. 31, 2014; Unit 4 (500 MW) would continue to operate with retrofits; and
- Welsh Plant, Pittsburg, Texas – Unit 2 (528 MW) retired by Dec. 31, 2014; Units 1 and 3 (1,056 MW) would continue to operate with retrofits.

The two coal-fueled generating units at Northeastern Plant (935 MW) in Oolagah, Okla., would be idled for a year or more while emission reduction equipment is installed. Both units would be idled beginning Jan. 1, 2016. One unit would return to service by Dec. 31, 2016. The other unit would return to service by Dec. 31, 2017.

AEP will complete construction of the Dresden Plant (580 MW natural gas) in Dresden, Ohio, in 2012.

In addition to the retrofits above, AEP would install or upgrade emissions reduction equipment at seven other coal-fueled power plants in Arkansas, Indiana, Louisiana, Ohio and Texas.

American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

This report made by American Electric Power and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, AEP's service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing AEP's ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material; electric load and customer growth; weather conditions, including storms, and AEP's ability to recover significant storm restoration costs through applicable rate mechanisms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of necessary generating capacity and the performance of AEP's generating plants; AEP's ability to recover Indiana Michigan Power's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process; AEP's ability to recover regulatory assets and stranded costs in connection with deregulation; AEP's ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; AEP's ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of AEP's plants; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including AEP's dispute with Bank of America); AEP's ability to constrain operation and maintenance costs; AEP's ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities; changes in the creditworthiness of the counterparties with whom AEP has contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of electric security plans and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by AEP's pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices and demand for power that AEP generates and sells at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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Exhibit JAL-3
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FirstEnergy's Ohio Utilities Meet Compliance Benchmarks Through Request for Renewable Energy Credits

FirstEnergy's (NYSE: FE) Ohio utilities – Ohio Edison, Cleveland Electric Illuminating Company and Toledo Edison – held a successful Request for Proposal (RFP) to secure 10-year Renewable Energy Credits (RECs) and Solar Renewable Energy Credits (SRECs) to help meet the renewable energy benchmarks established under Ohio's energy law.

With the successful subscription of this RFP, FirstEnergy's Ohio utilities have achieved their full compliance requirements for 2011, including the 2010 shortfall.

The RFP sought and procured the delivery of 5,000 SRECs and 20,000 RECs produced by generating facilities throughout Ohio for each calendar year beginning in 2011 and continuing through 2020.

"The robust participation in this RFP is evidence of a maturing renewable energy credit market throughout Ohio," says Dennis Chack, President of Ohio operations for FirstEnergy. "There were 28 qualified bids received, offering more than two times the required number of SRECs and over four times the required number of RECs, and many of the credits are originating in Toledo, Cleveland and other cities in our service area."

RECs and SRECs represent the environmental attributes of renewable and solar renewable electricity generation, respectively. For every megawatt hour of renewable or solar renewable electricity generated, an equivalent amount of RECs or SRECs are produced.

FirstEnergy is a diversified energy company dedicated to safety, reliability and operational excellence. Its 10 electric distribution companies comprise the nation's largest investor-owned electric system. Its diverse generating fleet features non-emitting nuclear, scrubbed baseload coal, natural gas, and pumped-storage hydro and other renewables, and has a total generating capacity of nearly 23,000 megawatts.

Forward-Looking Statement: This news release includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Actual results may differ materially due to: the speed and nature of increased competition in the electric utility industry, the impact of the regulatory process on the pending matters in the various states in which we do business including, but not limited to, matters related to rates, the status of the PATH project in light of PJM's direction to suspend work on the project pending review of its planning process, its re-evaluation of the need for the project and the uncertainty of the timing and amounts of any related capital expenditures, business and regulatory impacts from ATSI's realignment into PJM Interconnection, L.L.C., economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices and availability, financial derivative reforms that could increase our liquidity needs and collateral costs, the continued ability of FirstEnergy's regulated utilities to collect transition and other costs, operation and maintenance costs being higher than anticipated, other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water intake and coal combustion residual regulations, the potential impacts of any laws, rules or regulations that ultimately replace CAIR including the Cross-State Air Pollution Rule (CSAPR) and the effects of the EPA's recently released MACT proposal to establish certain mercury and other emission standards for electric generating units, the uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any NSR litigation or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to shut down or idle certain generating units), adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to, the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC, including as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant), issues that could delay the current outage at Davis-Besse for the installation of the new reactor vessel head, including indications of cracking in the plant's shield building currently under investigation, adverse legal decisions and outcomes related to Met-Ed's and Penelec's ability to recover certain transmission costs through their transmission service charge riders, the continuing availability of generating units and changes in their ability to operate at or near full capacity, replacement power costs being higher than anticipated or inadequately hedged, the ability to comply with applicable state and federal reliability standards and energy efficiency mandates, changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency mandates, the ability to accomplish or realize anticipated benefits from strategic goals, efforts, and our ability to improve electric commodity margins and the impact of, among other factors, the increased cost of coal and coal transportation on such margins, the ability to experience growth in the distribution business, the changing market conditions that could affect the value of assets held in FirstEnergy's nuclear decommissioning trusts, pension trusts and other trust funds, and cause

Exhibit JAL-3
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FirstEnergy to make additional contributions sooner, or in amounts that are larger than currently anticipated, the ability to access the public securities and other capital and credit markets in accordance with FirstEnergy's financing plan, the cost of such capital and overall condition of the capital and credit markets affecting FirstEnergy and its subsidiaries, changes in general economic conditions affecting FirstEnergy and its subsidiaries, interest rates and any actions taken by credit rating agencies that could negatively affect FirstEnergy's and its subsidiaries' access to financing or their costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees, the continuing uncertainty of the national and regional economy and its impact on the major industrial and commercial customers of FirstEnergy's subsidiaries, issues concerning the soundness of financial institutions and counterparties with which FirstEnergy and its subsidiaries do business, issues arising from the recently completed merger of FirstEnergy and Allegheny Energy, Inc. and the ongoing coordination of their combined operations including FirstEnergy's ability to maintain relationships with customers, employees or suppliers, as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect, the risks and other factors discussed from time to time in FirstEnergy's and its applicable subsidiaries' SEC filings, and other similar factors. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. FirstEnergy expressly disclaims any current intention to update any forward-looking statements contained herein as a result of new information, future events or otherwise.

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Table A: 2010 LTFR Data and AEP Ohio in-state Solar REC Requirement

Year	AEP Assumed Load at Generator (GWh)	System Losses (GWh)	AEP Ohio Total Distr. Meter Load (GWh)	Assumed Shopping Load Percentage	AEP Ohio Assumed Shopping Load (GWh)	AEP Ohio Net SSO Load (GWh)	Economic Adjustment Load (GWh)	AEP Ohio Net SSO Load (GWh)	AEP Obligation Basis (MWh)	In-State SREC Percentage	AEP Ohio In-State SREC Requirement (MWh)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
2012	51,718	3,766	47,952	9.26%	4,441	43,511	3,909	39,602	41,590	0.030%	12,477
2013	51,932	3,722	48,210	10.38%	5,006	43,204	3,909	39,295	40,569	0.045%	18,256
2014	51,888	3,728	48,160	10.50%	5,056	43,104	3,909	39,195	39,853	0.060%	23,912
2015	51,739	3,729	48,010	10.63%	5,104	42,906	3,909	38,997	39,364	0.075%	29,523
2016	51,621	3,761	47,860	10.76%	5,151	42,709	3,909	38,800	39,162	0.090%	35,246
2017	51,532	3,733	47,799	10.88%	5,199	42,600	3,909	38,691	38,997	0.110%	42,897
2018	51,490	3,705	47,785	10.98%	5,248	42,537	3,909	38,628	38,829	0.130%	50,478
2019	51,302	3,676	47,626	11.12%	5,297	42,329	3,909	38,420	38,706	0.150%	58,060
2020	50,932	3,666	47,266	11.31%	5,345	41,921	3,909	38,012	38,580	0.170%	65,585

Notes:

[1] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1 (net of DSM).
[2] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1.
[3] Equals [1] - [2].
[4] Equals [5] / [3].
[5] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1.
[6] Equals [3] - [5].
[7] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1.
[8] Equals [6] - [7].
[9] Equals average of three previous years' net SSO load.
[10] Source: R.C. 4928.64.
[11] Equals [9] x [10].

Table B: Recalculation of AEP Ohio in-state Solar REC Requirement Assuming 2012 Actual Shopping Level of 36.7%

Year	AEP Assumed Load at Generator (GWh)	System Losses (GWh)	AEP Ohio Total Distr. Meter Load (GWh)	Assumed Shopping Load Percentage	AEP Ohio Assumed Shopping Load (GWh)	AEP Ohio Net SSO Load (GWh)	Economic Adjustment Load (GWh)	AEP Ohio Net SSO Load (GWh)	AEP Obligation Basis (MWh)	In-State SREC Percentage	AEP Ohio In-State SREC Requirement (MWh)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
2012	51,718	3,766	47,952	36.70%	17,598	30,354	3,909	26,445	41,590	0.030%	12,477
2013	51,932	3,722	48,210	36.70%	17,693	30,517	3,909	26,608	36,183	0.045%	16,282
2014	51,888	3,728	48,160	36.70%	17,675	30,485	3,909	26,576	31,238	0.060%	18,743
2015	51,739	3,729	48,010	36.70%	17,620	30,390	3,909	26,481	26,543	0.075%	19,907
2016	51,621	3,761	47,860	36.70%	17,565	30,295	3,909	26,386	26,555	0.090%	23,900
2017	51,532	3,733	47,799	36.70%	17,542	30,257	3,909	26,348	26,481	0.110%	29,129
2018	51,490	3,705	47,785	36.70%	17,537	30,248	3,909	26,339	26,405	0.130%	34,327
2019	51,302	3,676	47,626	36.70%	17,479	30,147	3,909	26,238	26,358	0.150%	39,537
2020	50,932	3,666	47,266	36.70%	17,347	29,919	3,909	26,010	26,308	0.170%	44,724

Notes:

[1] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1 (net of DSM).
[2] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1.
[3] Equals [1] - [2].
[4] Based on 2012 shopping, as reported in Allen Affidavit, 3/7/2012.
[5] Equals [4] x [4].
[6] Equals [3] - [5].
[7] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1.
[8] Equals [6] - [7].
[9] Equals average of three previous years' net SSO load.
[10] Source: R.C. 4928.64.
[11] Equals [9] x [10].

Table C: Recalculation of AEP Ohio in-state Solar REC Requirement with 79% shopping load (2013 - 2020)

Year	AEP Assumed Load at Generator (GWh)	System Losses (GWh)	AEP Ohio Total Distr. Meter Load (GWh)	Assumed Shopping Load Percentage	AEP Ohio Assumed Shopping Load (GWh)	AEP Ohio Net SSO Load (GWh)	Economic Adjustment Load (GWh)	AEP Ohio Net SSO Load (GWh)	AEP Obligation Basis (MWh)	In-State SREC Percentage	AEP Ohio In-State SREC Requirement (MWh)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
2012	51,718	3,766	47,952	36.70%	17,598	30,354	3,909	26,445	41,590	0.030%	12,477
2013	51,932	3,722	48,210	79.00%	38,086	10,124	3,909	6,215	36,183	0.045%	16,282
2014	51,888	3,728	48,160	79.00%	38,046	10,114	3,909	6,205	24,441	0.060%	14,664
2015	51,739	3,729	48,010	79.00%	37,928	10,082	3,909	6,173	12,955	0.075%	9,716
2016	51,621	3,761	47,860	79.00%	37,809	10,051	3,909	6,142	6,198	0.090%	5,578
2017	51,532	3,733	47,799	79.00%	37,761	10,038	3,909	6,129	6,173	0.110%	6,790
2018	51,490	3,705	47,785	79.00%	37,750	10,035	3,909	6,126	6,148	0.130%	7,992
2019	51,302	3,676	47,626	79.00%	37,625	10,001	3,909	6,092	6,132	0.150%	9,198
2020	50,932	3,666	47,266	79.00%	37,340	9,926	3,909	6,017	6,116	0.170%	10,397

Notes:

[1] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1 (net of DSM).
[2] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1.
[3] Equals [1] - [2].
[4] Based on 2012 shopping, as reported in Allen Affidavit, 3/7/2012.
[5] Equals [4] x [4].
[6] Equals [3] - [5].
[7] Source: 2010 LTFR Supplement, Supplemental Appendix 1, Exhibit 1.
[8] Equals [6] - [7].
[9] Equals average of three previous years' net SSO load.
[10] Source: R.C. 4928.64.
[11] Equals [9] x [10].

6.3.5 Renewable Alternatives—Economic Screening Results

AEP has established an internal renewable target of 10% of System energy (total East and West zones) from renewable resources by 2020 (see **Appendix E**). Based on current AEP renewable resources, and considering an additional 1,000 MW of renewable resources committed to by the year-end 2014, together with the prospective renewable projects listed in **Exhibit 6-7**, included in the 2010 IRP (AEP-East and SPP), this internal commitment is projected to be satisfied. Note that the 2014 target represents an approximate 3-year shift in prior (2009 IRP) planned commitments of 2,000 MW of System-wide renewable resources by the end of *2014*; however, as recent unfavorable regulatory decisions in both Virginia and Kentucky surrounding cost recovery of planned wind purchase transactions has resulted in this "extension" of that prior goal.

Exhibit 6-7: Renewable Sources Included in AEP-East and AEP-SPP 2010

AEP-System
Existing and Projected Renewables for 2010 IRP

Unit, Plant, or Contract	Unit Type: Solar	Unit Type: Wind	Unit Type: Biomass	Size (MW)	First Full Energy Year	Renewable as % of Sales	Notes
Wind (SW Mesa)		X		31	Existing	0.1%	Existing (RECs only)
Wind (Weatherford)		X		147	Existing	0.5%	Existing
Wind (Blue Canyon II)		X		151	Existing	0.9%	Existing (RECs only until 2013)
Wind (Sleeping Bear)		X		95	Existing	1.2%	Existing
Wind (Camp Grove)		X		75	Existing	1.4%	Existing
Wind (Fowler Ridge I & III)		X		200	2010	1.8%	Executed PPA
Wind (Grand Ridge II & III)		X		101	2010	2.0%	Executed PPA
Wind (Fowler Ridge II)		X		150	2010	2.4%	Executed PPA (Add'l take)
Wind (Majestic)		X		80	2010	2.8%	Executed PPA (RECs only until 2012)
Wind (Blue Canyon V)		X		99	2010	2.9%	Executed PPA (RECs only until 2013)(Add'l take)
Wind (Beech Ridge)		X		101	2011	3.1%	Executed PPA(PSC-Apprvd)
Wind (Elk City)		X		99	2011	3.3%	Executed PPA (RECs only until 2013)(Add'l take)
Solar (Wyandot)	X			10	2011	3.4%	Executed PPA
Solar (Ohio)	X			10	2011	3.4%	w/ ITC
Biomass (Ohio units)			X	44	2011	3.5%	Ohio Units 10% Co-Fire
Wind (East)		X		100	2012	3.6%	w/ PTC
Wind (Minco)		X		100	2012	3.9%	Minco (PSO)
Solar (Ohio)	X			10	2012	3.9%	w/ ITC
Wind (East)		X		100	2013	4.1%	w/ PTC
Solar (Ohio)	X			10	2013	4.1%	w/ ITC
Biomass (East)			X	50	2014	4.4%	RECs PPA or Unit Co-Fire (No New Capacity)
Wind (East)		X		300	2014	5.0%	No PTC
Solar (Ohio)	X			26	2014	5.0%	w/ ITC
Wind (East)		X		400	2015	5.9%	No PTC
Wind (West)		X		200	2015	6.4%	No PTC
Solar (Ohio)	X			26	2015	6.4%	w/ ITC
Solar (Distributed)	X			25	2015	6.5%	(E&W) No ITC
Biomass (Ohio units)			X	(44)	2016	6.3%	Retirement of Ohio Units 10% Co-Fire
Wind (West)		X		200	2016	6.9%	No PTC
Wind (East)		X		250	2016	7.4%	No PTC
Solar (Ohio)	X			26	2016	7.4%	No ITC
Wind (West)		X		200	2017	7.9%	No PTC
Wind (East)		X		150	2017	8.2%	No PTC
Solar (Ohio)	X			26	2017	8.3%	No ITC
Solar (Ohio)	X			26	2018	8.3%	No ITC
Wind (East)		X		50	2018	8.4%	No PTC
Biomass (East)			X	100	2018	8.9%	RECs PPA or Unit Co-Fire (No New Capacity)
Wind (East)		X		100	2019	9.1%	No PTC
Solar (Ohio)	X			26	2019	9.1%	No ITC
Wind (West)		X		300	2020	9.9%	No PTC
Wind (East)		X		150	2020	10.2%	No PTC
Solar (Ohio)	X			26	2020	10.2%	No ITC

Source: AEP Resource Planning

Exhibit JAL-7

Transmission Construction Status

Queue	Queue Date	PJM Substation	MW	MWC	MWE	Status	Feas	Imp	Fac	ISA	CSA	St	In Service	Fuel
V3-028	08/31/2009	East Lima-Marysville 345kV	20	7.6	20		●	●				OH	2011 Q4	
V4-073	01/29/2010	Yankee 12.5kV	3	0.95	2.5		●	●	⊗	⊗	⊗	OH	2010 Q2	
W2-040	06/29/2010	Camden 69kV	0	7.6	20		●	●	⊗	●	●	OH	2017 Q2	
W3-111	10/29/2010	S. Cumberland 69kV	20	7.6	20		●	●	○			OH	2012 Q4	
W3-112	10/29/2010	S. Cumberland 69kV	20	7.6	20		●	●	○			OH	2013 Q4	
W3-113	10/29/2010	S. Cumberland 69kV	20	7.6	20		●	●	○			OH	2014 Q4	
W3-170	10/29/2010	Buckskin 69kV	12	0	12		●	○				OH	2011 Q3	
W4-036	12/28/2010	Buckskin 69kV	12	0	12		●	●	○			OH	2011 Q4	
X1-033	03/17/2011	NCEC Sycamore 69/12.47kV	12	0	12		○					OH	2012 Q1	
X2-085	07/29/2011	Barberton-Seiberling 23kV	14	0	14		●	○				OH	2012 Q4	
X3-001	08/01/2011	West Melrose 34.5kV	2	0.69	1.82		●	●	⊗	⊗	⊗	OH	2012 Q4	
X3-002	08/01/2011	Greenville 12kV	3	1.28	3.38		●	●				OH	2012 Q3	
X3-053	09/29/2011	Homer-Seville 69kV	18	6.72	17.68		●	○				OH	2013 Q3	
X3-059	10/10/2011	Roberts 34.5kV	20	7.6	20		●					OH	2012 Q3	
X4-030	12/30/2011	Freemont 69kV	14	5.23	13.75		○					OH	2013 Q2	
Y1-023	02/28/2012	Felicity 69kV	20	7.6	20		○					OH	2013 Q4	
Y1-024	02/28/2012	Felicity 12.5kV	5	1.9	5		○					OH	2013 Q4	

Total 215 MW

Turning Point is highlighted.

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Transmission Construction Status

Queue	Queue Date	PJM Substation	MW	MWC	MWE	Status	Feas	Imp	Fac	ISA	CSA	St	In Service	Fuel
T20	08/30/2007	Falls	3	1.1	3.3		●	●	⊗	●	●	PA	2008 Q4	
U4-014	11/24/2008	Siegfried-Hauto 69kV	10	3.8	10	◆	●	●	●	●	●	PA	2012 Q4	
V3-040	09/17/2009	Siegfried-Hauto 69kV	10	3.8	10	◆	●	●	⊗	●	●	PA	2014 Q2	
V3-062	10/30/2009	McConnellsburg-Guilford 138kV	20	7.6	20		●	●	⊗			PA	2011 Q4	
V4-027	12/07/2009	Quarryville	5	1.9	5	◆	●	●	⊗	⊗	⊗	PA	2012 Q3	
V4-075	01/29/2010	Warwick 12kV	2	0.76	2	◆	●	●	⊗	⊗	⊗	PA	2012 Q1	
V4-076	01/29/2010	Carlisle Pike 23kV	5	2	5.3	◆	●	●	⊗	⊗	⊗	PA	2011 Q2	
V4-077	01/29/2010	Montgomery Avenue 12.47kV	13	4.9	13	◆	●	●	⊗	⊗	⊗	PA	2012 Q2	
W1-045	03/04/2010	Roxbury 23 kV	14	5.13	13.5		●	●	⊗			PA	2011 Q3	
W1-046	03/04/2010	Face Rock 69kV	15	5.7	15	▼	●	●	⊗	●	●	PA	2015 Q2	
W1-075	04/28/2010	Hunterstown 115kV	20	7.6	20		●	●	○	⊗	⊗	PA	2012 Q4	
W1-104	04/30/2010	Bellefonte 12kV	1	0.25	0.65		●	●	⊗	⊗	⊗	PA	2011 Q4	
W1-105	04/30/2010	Reamstown	3	1.14	3	◆	●	●	⊗	⊗	⊗	PA	2014 Q2	
W1-106	04/30/2010	West Carlisle	5	1.9	5	◆	●	●	⊗	⊗		PA	2014 Q2	
W1-107	04/30/2010	Grove City road 12kV	2	0.74	2		●	●	⊗	⊗	⊗	PA	2011 Q4	
W1-114	04/30/2010	Port Carbon	3	1.14	3	◆	●	●	⊗	⊗		PA	2012 Q4	
W1-115	04/30/2010	Tamanend	3	1.14	3	◆	●	●	⊗	⊗		PA	2012 Q4	
W2-092	07/30/2010	Hunterstown 115kV II	20	7.6	20		●	●	○			PA	2013 Q2	
W2-093	07/30/2010	Hunterstown 115kV III	20	7.6	20		●	●	○			PA	2013 Q2	
W2-094	07/30/2010	Straban 13.2 kV	3	1.1	3		●	●				PA	2012 Q2	
W2-098	07/30/2010	Hunterstown 115kV IV	20	7.6	20		●	●	○			PA	2013 Q2	
W3-008	08/06/2010	Mercersburg 34.5kV	20	7.6	20		●	●	○			PA	2012 Q3	
W3-072	09/30/2010	St. Thomas-Guilford 34.5kV	20	7.6	20		●	●	○			PA	2012 Q3	
W3-167	10/29/2010	Nottingham II	10	3.8	10		●	●				PA	2011 Q4	
W4-042	12/30/2010	McConnellsburg 34.5kV	15	5.7	15		●	●				PA	2012 Q3	
X1-035	03/24/2011	Piney 34.5kV I	2	0.76	2		●	●	⊗			PA	2011 Q4	
X1-036	03/24/2011	Piney 34.5kV II	2	0.76	2		●	●	⊗			PA	2011 Q4	
X2-007	05/12/2011	Peckville-Varden 69kV	15	5.7	15		●	●	○			PA	2012 Q2	
X2-034	06/03/2011	Laplume	0	0	0.032		●	●				PA		
X3-022	08/29/2011	Hunterstown-Jackson 130kV	100	38	100		●					PA	2014 Q4	
X3-062	10/11/2011	Upton 34.5kV	20	7.6	20		●					PA	2012 Q4	
X4-001	11/02/2011	St. Thomas-Guilford 34.5kV	20	7.6	20		○					PA	2012 Q4	
X4-002	11/02/2011	St. Thomas-Guilford 34.5kV	20	7.6	20		○					PA	2012 Q4	

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X4-009	11/17/2011	Cumberland - W. Shore #1 69kV	20	7.6	20							PA	2012 Q4	
X4-010	11/17/2011	Cumberland - W. Shore #2 69kV	20	7.6	20							PA	2012 Q4	
X4-011	11/17/2011	Mercersburg-Milner 34.5kV	20	7.6	20							PA	2012 Q4	
Y1-022	02/28/2012	Cooper	10	3.8	10							PA	2013 Q4	

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Summary: Testimony of Jonathan A. Lesser electronically filed by Mr. Nathaniel Trevor Alexander on behalf of FirstEnergy Solutions Corp.