BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals	))))	**Case No. 10-2376-EL-UNC**
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan	))))))	**Case No. 11-346-EL-SSO** **Case No. 11-348-EL-SSO**
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	))))	**Case No. 11-349-EL-AAM** **Case No. 11-350-EL-AAM**
In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders	))))	**Case No. 10-343-EL-ATA**
In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders	))))	**Case No. 10-344-EL-ATA**
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**
In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Ordered Under Ohio Revised Code 4928.144	)))))	**Case No. 11-4920-EL-RDR**

DIRECT TESTIMONY OF
JONATHAN A. LESSER
ON BEHALF OF FIRSTENERGY SOLUTIONS CORP.

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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 destroyed 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 previously filed testimony in Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM and 11-350-EL-AAM.

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

A. I will address several facets of the Stipulation between Columbus Southern Power Company ("CSP") and Ohio Power Company ("OPC") (collectively, "AEP Ohio") and various signatories to the Stipulation and Recommendation ("Stipulation"), dated September 7, 2011, and testimony in support of that stipulation filed on September 13, 2011.

Q. WHAT ROLE DOES AEP OHIO'S ELECTRIC SECURITY PLAN ("ESP") PLAY IN OHIO'S COMPETITIVE MARKET FOR RETAIL ELECTRIC GENERATION SERVICE?

A. The Stipulation is intended to allow AEP Ohio to provide a Standard Service Offer ("SSO") using an ESP – in what Ohio has said should otherwise be a diverse and innovative market for CRES.[1] More than ten years ago, Ohio declared that retail electric generation and aggregation services, among others, would be competitive services in Ohio.[2] Ohio also directed electric distribution utilities such as AEP Ohio to offer consumers an SSO to which they always may default from the CRES market. AEP Ohio has the option of providing an SSO either through an ESP or a Market Rate Offer ("MRO"), which uses a competitive bidding process to establish the SSO price. In either case, because the SSO is a default option for consumers, the SSO under the Stipulation either must fairly represent market pricing (the MRO) or be more favorable in the aggregate than market pricing (the ESP).

As part of the Stipulation, AEP Ohio proposes to update its existing ESP, rather than develop an MRO. To be consistent with state policy, the ESP proposed in the Stipulation must still provide consumers with unbiased choices over the selection of electricity supplies and suppliers, encourage market access for cost-effective supply of retail electric service and ensure effective competition in the provision of retail electric service. Therefore, the ESP proposed in the Stipulation should not unfairly foreclose market competition or generate market deficiencies. It also should not degrade Ohio's effectiveness in the global economy by erecting barriers to market competition. As I discuss below, in fact, the Stipulation <u>will</u> foreclose market competition and create market inefficiencies, contrary to state policy.

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[1] *See* R.C. 4928.02(C), (D). "It is the policy of this state to do the following throughout this state: (C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies … (D) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service …"

[2] *See* R.C. 4928.03.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE ESP.

First, in Section II, I address the proposal by AEP Ohio to charge CRES providers $255/MW-day for capacity, a price that is neither cost-based nor market-based, and is almost four times the average PJM RPM market price for capacity over the period of the proposed ESP. As I show, this capacity price will allow AEP Ohio to double-recover costs which it had previously agreed to forgo as part of the transition to competition starting in 2001. Moreover, contrary to the testimony of AEP Ohio witness Allen,[3] charging the RPM market price to a subset of customers instead of AEP Ohio's claimed full embedded cost capacity price of $355.72/MW-day will <u>not</u> provide $856 million in present value savings to ratepayers. Mr. Allen erroneously presumes that AEP Ohio is <u>entitled</u> to collect all of its embedded capacity costs, but it cannot justify charging anything more than the RPM price. As part of the transition to competition, AEP Ohio's ability to recover generation transition costs ("GTCs") expired at the end of 2005, and its ability to recover regulatory transition costs ("RTCs") expired at the end of 2008. As AEP Ohio has already had over 10 years to make the "transition to competition," there is simply no economic basis for allowing it to continue that "transition" for the term of the proposed ESP. Indeed, because all shopping customers unfortunate enough to be denied the RPM set-aside capacity will have to pay $255/MW-day for capacity, the Stipulation imposes a cost on customers that, if all shopped, would <u>increase</u> the present value <u>cost</u> of the Stipulation by $1.27 billion. I also show that, because the price AEP Ohio charges for capacity is what economists call a "transfer" price, the economically efficient price for capacity is, in fact, the PJM RPM market price. Finally, I show that, if AEP Ohio is not required to charge the RPM price for capacity, then the appropriate capacity charge, based solely on AEP Ohio's net, undepreciated pre-2001 (pre-transition)

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[3] Direct testimony of William D. Allen in support of the Stipulation and Recommendation on behalf of Columbus Southern Power Company and Ohio Power Company, September 13, 2011 ("Allen Testimony").

embedded generation plant investment, with appropriate offsets for all revenues that contribute to that generation plant investment, is $57.35/MW-day.

Next, in Section III, I address the adverse competitive impacts of the proposed ESP's rate design. Other than the provision requiring AEP to provide capacity at the RPM market price immediately for a subset of customers, the proposed rate design has no regulatory basis and is discriminatory, in that it increases rates the most on residential customers who are less likely to take service from CRES providers, while decreasing rates on commercial and industrial customers who are most likely to take service from CRES providers. Furthermore, AEP Ohio's proposal under the Stipulation to allocate future capacity costs using a cost-based approach belies its use of "market prices" to set SSO retail rates for all customer classes. I next discuss why the proposal of a nonbypassable Market Transition Rider ("MTR") and shopping credit is anticompetitive, in that it clearly subsidizes selected rate classes at the expense of other rate classes, including other customers who purchase electricity from CRES providers. Similarly, the proposed nonbypassable Generation Resource Rider ("GRR"), under which AEP proposes to include the costs of its proposed Turning Point Solar Facility and a new 500 MW combined-cycle generating plant at Muskingum River ("MR6") is anticompetitive. Not only does the proposed nonbypassable rider foreclose competition, it places the financial risks of generating resource development back onto ratepayers, which is economically inefficient and one of the guiding reasons for establishing competitive electric markets. The GRR also presumes that AEP Ohio can always "beat the market," which has no basis in fact. And, because of how the Stipulation will allow AEP Ohio to bid energy from GRR facilities into the market, AEP Ohio will be guaranteed a return on those facilities that is greater than a risk-comparable value, contrary to long-established regulatory principles. Finally, because AEP Ohio has not established the costs of the GRR at this time, there is no basis for allowing AEP to incorporate it at this time.

Finally, in Section IV, I address the adverse impact on jobs in the State of Ohio over the term of the proposed ESP. Again, whereas AEP Ohio touts the economic benefits of the

Stipulation, allowing AEP Ohio to continue charging above-market prices for capacity and foreclosing competition through the nonbypassable MTR and GRR riders will damage the Ohio economy and lead to lost jobs.

II. AEP OHIO'S CAPACITY COST PROPOSAL IS EXCESSIVE, ALLOWS IT TO DOUBLE-COLLECT REVENUES, AND FAILS TO PROPERLY REFLECT MARKET PRICING.

Q. PLEASE SUMMARIZE YOUR OBJECTIONS TO THE $255/MW-DAY CAPACITY PRICE IN THE STIPULATION.

A. Except for a set-aside amount, the Stipulation proposes that CRES providers be charged $255/MW-day for capacity over the first 41 months of the ESP and that the capacity price be the PJM RPM market price in the last 12 months of the ESP. AEP Ohio provides no justification for this capacity price, which is neither cost-based nor market-based. AEP further claims that, by agreeing to set its capacity costs to $255/MW-day and by limiting lower-cost RPM capacity to a minority of customers, the Stipulation will provide a "steady path to fully competitive markets for supplying electricity to AEP Ohio's customers."[4]

As I discuss below, the capacity price AEP Ohio charges CRES providers can be thought of as what economists call a "transfer price." The economically efficient transfer price is, in fact, the PJM market price. To charge, as the Stipulation proposes, a price that is four times larger than the average PJM RPM market price is economically inefficient and unduly discriminatory. Furthermore, because AEP Ohio previously agreed to forego collection of stranded costs, the company should not be allowed to collect any above-market capacity costs. And, even if, *arguendo*, a non-market, cost-based price were appropriate, I show below that it should not include generating plant investment made after the January 1, 2001 transition date for market competition, nor allow AEP Ohio to double-recover revenues from off-system energy sales,

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[4] Direct testimony of Joseph Hamrock in support of the Stipulation and Recommendation on behalf of Columbus Southern Power Company and Ohio Power Company, September 13, 2011 ("Hamrock Testimony").

which the Stipulation will allow AEP Ohio to do. There is simply no economic reason for an additional three-year, five-month, "transition" period to competition, which serves only to allow AEP Ohio to recover embedded generation costs that, under the terms of the Stipulation AEP Ohio signed over 10 years ago as part of its Electric Transition Plan ("ETP") proceeding, it no longer is allowed to recover.

A. <u>The Only Economically Efficient Capacity Price is the PJM RPM Price.</u>

Q. WHY IS THE CAPACITY PRICE AEP OHIO CHARGES A TRANSFER PRICE?

A. A transfer price is a price that one part of a firm charges another part. In some cases, there is no external market for the commodity or service sold internally. In other cases, there is an external market. For example, suppose a firm has an upstream and downstream division. The upstream division generates electricity, all of which supplies the downstream division's electric arc furnace for manufacturing steel. The electric generating division "sells" the electricity it generates to the steel manufacturing division. The transfer price is the sales price of electricity "sold" by the generating division to the steel manufacturing division. In the same way, AEP Ohio's capacity price can be thought of as an internal transfer price of capacity sold to SSO customers and CRES providers. Rather than purchasing capacity from the market, which in this case is the PJM RPM, SSO customers and CRES providers must purchase capacity from AEP Ohio.

Q. IS THE $255/MW-DAY CAPACITY PRICE THAT CUSTOMERS WILL BE CHARGED AN ECONOMICALLY EFFICIENT TRANSFER PRICE?

A. No. A standard economic result associated with transfer pricing is to determine the economically efficient price. When there is an external market for the good being "transferred" internally, the most efficient price is the external market-clearing price. If the transfer price is higher than the market price, then the "downstream" division would be better off buying the commodity directly from the market. If the price is set lower than the market price, then the upstream division is losing money by subsidizing the downstream division's purchase of the commodity.

Q. WHY ARE CRES PROVIDERS CAPTIVE CUSTOMERS OF AEP OHIO FOR CAPACITY?

A. A CRES provider who wishes to sell energy to AEP Ohio's retail customers must also obtain sufficient capacity reserves. These capacity reserves can be obtained in one of two ways. First, under the FRR alternative, a CRES provider can obtain its capacity from AEP Ohio, which elected the FRR alternative to self-supply capacity, to serve retail customers. Because AEP Ohio has elected the FRR option for all retail load in its region through May 31, 2015, Ohio CRES providers sell retail customers energy at a negotiated rate that includes AEP Ohio's approved capacity charge for shopping load. Effectively, CRES providers are buying the capacity they need from AEP Ohio at the PUCO-approved rate and providing it to the departing load it now serves.

Alternatively, by giving PJM three years' advance notice before the applicable Base Residual Auction for a specific delivery year, a CRES provider can supply its own capacity. This means that, presently, a CRES provider in AEP Ohio's service territory could not self-supply capacity until the 2015/16 planning year, which begins on June 1, 2015. To self-supply in early 2012 at the start of the proposed ESP, a CRES provider would have had to made this election in early 2008 at a time when AEP Ohio was relying on RPM to price capacity. If no election is made three years in advance, the CRES provider effectively is locked-in to obtaining capacity from AEP Ohio for the delivery year. CRES suppliers must rely on AEP Ohio to provide their capacity requirements for the next three years. Therefore, until 2015, CRES providers are captive customers of AEP Ohio who must purchase capacity as an "input" to sell their market commodity: retail electricity. That is why the price AEP Ohio charges CRES providers for capacity is a transfer price, and why AEP Ohio's proposal to charge CRES providers $255/MW-day is economically inefficient.

B. <u>The Proposed $255/MW-Day Capacity Price Imposes an Over One Billion Dollar Cost on AEP Ohio Ratepayers.</u>

Q. DO YOU AGREE WITH AEP OHIO WITNESS ALLEN'S ESTIMATE THAT, BY CHARGING $255/MW-DAY FOR CAPACITY, THE STIPULATION PROVIDES A PRESENT VALUE BENEFIT OF $856 MILLION TO AEP OHIO RATEPAYERS?

A. No. Mr. Allen's calculation is based on a strawman comparison, because it presumes that AEP Ohio is <u>entitled</u> to charge the full embedded cost rate that AEP has advanced for its capacity resources. Thus, he concludes that ratepayers "benefit" by not having to pay AEP's claimed full embedded cost. However, as I discuss below, AEP Ohio is not so entitled and, as a consequence, Mr. Allen's "benefit" calculation is specious. Moreover, as I discuss in Section II.C, the embedded cost calculation performed by AEP Ohio witness Pearce, on which the "Full Capacity Cost" market prices shown on page 3 of Exhibit LJT-1 are based, are themselves erroneous and are based on an assumption that AEP Ohio should be allowed to double-recover costs.

Q. HAVE YOU COMPARED THE COST TO AEP OHIO RATEPAYERS FROM BEING FORCED TO PAY THE $255/MW-DAY PRICE FOR CAPACITY IN THE STIPULATION VERSUS PAYING THE PJM RPM MARKET RATE?

A. Yes. For my analysis, I have used the data from AEP Ohio witness Allen Exhibit WAA-4 and his workpapers and AEP Ohio witness Thomas Exhibit LJT-1. The results of my analysis are shown in Table 1 below. The "market prices" shown in lines [2] – [4] of Table 1 are those derived by AEP Ohio witness Thomas. To derive an estimated ESP benefit of $856 million, Mr. Allen compared the spread between Ms. Thomas' "market price" using a capacity cost of $355.72/MW-day and her "market price" using RPM pricing.

Q. DO YOU AGREE WITH THE MARKET PRICES SHOWN IN EXHIBIT WAA-4 THAT ARE BASED ON THE PRICES SHOWN IN EXHIBIT LJT-1?

A. No. Mr. Schnitzer's testimony discusses the many flaws in the ESP v. MRO price comparisons performed by AEP witness Thomas, including the "market prices" she derives. The only "market price" that begins to approximate actual market pricing is that price that uses RPM capacity pricing. The other so-called "market prices" are not market at all. Charging less than $355.72/MW-day for capacity can only be a benefit of the Stipulation if shopping customers would have had to pay this amount under an MRO, which is not a reasonable assumption. Because AEP Ohio cannot justify charging more than the RPM price for capacity, charging this price to a subset of customers has a net present value benefit to customers of $0. Moreover, charging an above-market price for capacity to all other customers would result in a substantial net present value cost.

Q. WHAT DOES TABLE 1 SHOW?

In Table 1, I show that AEP Ohio witness Allen's capacity charge "benefit" estimate is based on an entirely false comparison, even assuming, *arguendo*, the market prices he bases that comparison on are valid.

Table 1: Present Value Cost of Above-Market Capacity Charges

Line	Item	Year			
		2012	2013	2014	2015
[1]	Connected Load (GWh)	47,676	47,896	47,843	19,688
[2]	Market Price at Full Capacity Cost	$77.03	$81.04	$84.06	$86.22
[3]	Market Price @ $255/MW-Day	$70.53	$74.66	$77.69	$79.85
[4]	Market Price @ RPM ($/MW-Day)	$57.16	$58.68	$66.64	$72.32
[5]	Difference	($13.37)	($15.98)	($11.05)	($7.53)
[6]	Assumed Shopping Level	21%	31%	41%	41%
[7]	Shopping Load (GWh)*	9,875	14,848	19,616	8,072
[8]	Non-shopping load (GWh)	37,148	33,048	28,227	11,616
[9]	Above-market Costs Paid (Million$)	($496.7)	($528.1)	($311.9)	($87.5)
[10]	**Present Value of Excess Costs Paid (Million$)**	**($1,269.8)**			

Notes:

[1] Source: Allen workpapers supporting Exhibit WAA-4.
[2] Source: Allen workpapers supporting Exhibit WAA-4.
[3] Source: Allen workpapers supporting Exhibit WAA-4.
[4] Source: Allen workpapers supporting Exhibit WAA-4.
[5] Equals [3] - [4].
[6] Source: Allen workpapers supporting Exhibit WAA-4.
[7] Source: Allen workpapers supporting Exhibit WAA-4. * For 2012 Allen assumed shopping load based upon 21% of 47,023 GWh
[8] Equals [1] - [7]. (See also note to [7] for 2012 amount.)
[9] Equals [5] x [8] / 1000.
[10] Discount rate of 6.0% used by Allen.

In Table 1, I compare Ms. Thomas' "market price" using the Stipulation's above-market capacity price of $255/MW-day to her "market price" using RPM clearing prices, and I then allocate this difference to AEP Ohio's load that is denied market pricing by the Stipulation. To determine the additional costs imposed on remaining load that does not fall under the assumed set-asides shown in Table 1, consider the following two alternatives. First, suppose all of the remaining "non-shopping" load in line [8] of Table 1 were to shop. Under the Stipulation, those customers would pay $255/MW-day under the stipulation. Therefore, the resulting cost to AEP Ohio ratepayers (and CRES providers) would be an additional $1.27 billion. Second, suppose that none of the other load shops, but instead continues to take SSO service. Within the base generating cost used by AEP Ohio witness Roush to determine the "market" rates SSO customers will pay, AEP Ohio must be implicitly charging those customers at least the $255/MW-day price it proposes to charge for capacity associated with additional shopping loads. Otherwise, AEP Ohio would be unfairly discriminating against CRES providers—charging CRES providers a higher price for capacity than it charges its own SSO customers. Therefore, all other non-shopping load in Table 1, whether it actually takes SSO service or all shops, and any combination of additional shopping and SSO service in between, must be paying at least $255/MW-day for capacity. This means that AEP Ohio is not providing an $856 million benefit to shopping customers, but rather is imposing a $1.27 billion cost on all customers who are not eligible to obtain market capacity prices.

Q. HOW DOES YOUR ESTIMATE OF THE ADDITIONAL CAPACITY COSTS THAT WILL BE PAID BY RATEPAYERS UNDER THE STIPULATION AFFECT THE QUANTIFIABLE BENEFITS OF THE ESP?

A. Correcting Mr. Allen's strawman comparison changes the $1,118 million present value benefit of the ESP shown in his Exhibit WAA-4 to a present value cost of over $1 billion, as shown in Table 2.

Table 2: Recalculation of Exhibit WAA-4 (Millions$)

Line	Item	NPV @ 6%	Year						
			2012	2013	2014	2015	2016	2017	2018
[1]	ESP Price Benefit for Non-Shopping Customers	$130	$21	$41	$51	$38			
[2]	Value of Discounted Capacity Provided to CRES Providers	($1,270)	($497)	($528)	($312)	($87)			
[3]	Reduced PIRR Carrying Costs	$104	$35	$32	$28	$24	$18	$12	$4
[4]	Partnership With Ohio Initiative	$10	$3	$3	$3	$3	$1		
[5]	Ohio Growth Fund Initiative	$17	$5	$5	$5	$5	$2		
[6]	Total Quantifiable ESP Benefits	($1,009)	($433)	($447)	($224)	($17)	$22	$12	$4

Table 2 assumes, *arguendo*, that all of the other estimated "benefits" shown in Exhibit WAA-4 are valid, even though these "benefits" are shown to be erroneous in Mr. Schnitzer's testimony. Thus, applying the correct perspective on AEP Ohio's being allowed to charge an above-market capacity price shows that the Stipulation would impose present value costs of over $1 billion on AEP ratepayers.

C. If AEP Ohio Does Not Charge the Market Price for Capacity, It Should Charge a Cost-Based Price that Includes Only Pre-Transition Embedded Costs

Q. WHAT IS AEP OHIO'S ARGUMENT FOR WHY CRES PROVIDERS SHOULD PAY A FULL EMBEDDED-COST RATE FOR CAPACITY?

A. AEP Ohio witness Pearce states that "By CRES providers paying a rate that is based upon average [embedded] costs, they are neither subsidizing nor being subsidized by CSP and OPCo."[5] For the merged company, the average embedded capacity cost calculated by Dr. Pearce is $355.72/MW-day, including transmission losses.[6]

[5] Direct testimony of Kelly D. Pearce in support of the Stipulation and Recommendation on behalf of Columbus Southern Power Company and Ohio Power Company, September 13, 2011 ("Pearce Testimony").

[6] *See* Exhibit KDP-4.

Q. IS AVOIDING SUBSIDIES AN IMPORTANT FACTOR IN ENSURING SUCCESSFUL COMPETITIVE MARKETS?

A. Yes. Subsidies can damage competitive markets in several ways. First, subsidies foreclose competition. For example, one of the issues that has been debated at PJM and FERC is some states effectively forcing local distribution utility customers to subsidize new generating facilities so those facilities can be bid into the PJM RPM and, as a result, artificially lower market-clearing prices. Such an outcome drives out legitimate competitors and eventually leads to higher market prices, as investors perceive greater risks of entering the market and developing new generating resources. Second, subsidies misallocate resources and thus reduce what economists call "allocative efficiency." For example, suppose a manufacturer is given "free" electricity to use in its manufacturing process. The manufacturer will have no incentive to use the electricity efficiently because the price is zero. This will lead to the manufacturer using too much electricity, reducing overall economic efficiency. Thus, for competitive markets to develop and thrive, it is critically important to avoid subsidies.

Q. IF AEP OHIO'S EMBEDDED CAPACITY COST IS MUCH HIGHER THAN THE PJM RPM MARKET PRICE, DOES CHARGING THE MARKET PRICE MEAN THAT CRES PROVIDERS ARE RECEIVING SUBSIDIZED CAPACITY?

A. No. Based on Dr. Pearce's logic, any price that CRES providers pay that is below AEP Ohio's embedded cost is a subsidy, including the proposed $255/MW-day capacity price CRES providers would pay under the Stipulation through May 2015.[7] Of course, starting in June 2015, CRES providers will presumably pay a market price for capacity that is well below AEP Ohio's claimed embedded costs, but that lower market price will <u>not</u> be a subsidy. Such illogic is the result of Dr. Pearce's definition of a subsidized rate. In reality, AEP wishes CRES providers, and their own SSO customers, <u>to pay AEP Ohio an above-market subsidy</u>. A competitive market price is <u>not</u>, as Dr. Pearce appears to believe, a subsidized one.

[7] In his deposition, Dr. Pearce states that the $255/MW-day price represents a subsidy. *See* Deposition of Kelly D. Pearce, 9/23/2011, at 48:2 - 49:10.

Q. HOW DID AEP DETERMINE THE "MARKET PRICE AT FULL CAPACITY COST" VALUES SHOWN ON LINE [2] OF YOUR TABLE 1?

A. The estimates shown in Line [2] of Table 1 were derived by AEP Ohio witness Thomas based on what is called a "formula rate" for the capacity price component. (The actual formula rate capacity price of $355.72/MW-day was developed by AEP Ohio witness Pearce.) A formula rate is a methodology by which a cost-based revenue requirement is calculated, in this case for the fixed costs of AEP Ohio's generating units, which are listed on page 4 of Exhibit WAA-1. The revenue requirement, **RR**, can be written as:

RR = O&M + DEPR +TAXES + (RETURN) *x* (RATE BASE) - $REV,

where:

O&M	=	fixed operation and maintenance expenses
DEPR	=	annual depreciation expense
TAXES	=	income and other tax payments
RETURN	=	overall rate of return on invested capital
RATE BASE	=	net book value of generating assets, plus CWIP, plus regulatory assets, plus working capital, less deferred income taxes.
$REV	=	revenues from sales for resale of energy, capacity, and ancillary services

The resulting revenue requirement is called the fixed (or embedded) production cost, and is the claimed basis for AEP's capacity cost estimates. The specific details of AEP Ohio's formula rate calculations are shown in AEP Ohio witness Pearce's Exhibits KDP-1 (CSP) and KDP-2 (OPC).

Exhibit KDP-4 summarizes the resulting costs and calculates the combined AEP Ohio embedded capacity cost. Dr. Pearce calculates CSP's embedded capacity costs to be $477.1 million for OPC's embedded capacity costs to be $660.5 million, for a total embedded capacity cost of $1,137.6 million. Combining that total with an overall 5CP average demand of 9,060.8 MW, he derives an overall $355.72/MW-day embedded capacity cost, which is used by AEP Ohio witness Thomas in her "market price" calculations on page 3 of Exhibit LJT-1.

Q. DOES THE $355.72/MW-DAY VALUE DR. PEARCE CALCULATES INCLUDE TRANSMISSION SYSTEM LOSSES?

A. Yes.

Q. DOES THE $255/MW-DAY CAPACITY PRICE UNDER THE STIPULATION INCLUDE LOSSES?

A. When asked that question in his deposition, Dr. Pearce stated he did not know the answer.[8]

Q. WHY DOES IT MATTER IF THE $255/MW-DAY VALUE DOES NOT INCLUDE LOSSES?

A. If it does not, it is one more reason why the ESP v. MRO comparisons prepared by Ms. Thomas (Exhibit LJT-1) are wrong, because the "Maximum RPM Rate" values developed by Dr. Pearce and shown in his Exhibit KDP-5 include losses. It is not valid to compare an ESP price that excludes losses with MRO prices that include them.

D. Because AEP Ohio Previously Agreed to Forego Collection of Stranded Costs and to Recover Its Generation Costs in the Competitive Markets, It Should not be Allowed to Impose an Above-Market Capacity Price.

Q. WHAT IMPACT DID S.B. 3 HAVE ON THE ABILITY OF ELECTRIC UTILITIES TO IMPOSE ABOVE-MARKET PRICES IN ORDER TO RECOVER THEIR FULL EMBEDDED COSTS FOR THEIR GENERATING CAPACITY RESOURCES?

A. Under S.B. 3, which unbundled retail electric generation service from distribution and transmission service beginning January 1, 2001, all generation plant investment after that date was to be recovered solely in the market. Under S.B. 3, each electric utility was given an opportunity during a transition period to recover any previously-sunk costs in their generating facilities (*i.e.*, costs incurred prior to the transition date of January 1, 2001) that would be

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[8] Deposition of Kelly Pearce, 9/23/2011, at 25:11-15.

uneconomic or "stranded" in competitive markets.[9] Because S.B. 3 provided a clear demarcation date between pre-transition and post-transition generation costs, any cost-based capacity charges levied by AEP Ohio could apply only to generating plant that was in-service on or before December 31, 2000, the day before the transition date of January 1, 2001, and only then if AEP Ohio had not waived recovery and/or already fully recovered these costs during the transition period. As I discuss below, that transition period is long over.

Q. WHAT ARE STRANDED COSTS AND WHY ARE THEY RELEVANT TO AEP OHIO'S CAPACITY COST ESTIMATE?

A. Stranded costs are defined as the difference between the market value of an asset and its net undepreciated book value. For example, if a generating unit's market value is estimated at $500 million and its net book value is $600 million, then the unit has stranded costs of $100 million. Stranded costs are relevant to the capacity charge AEP Ohio proposes to charge all customers for two reasons. First, stranded costs hinge on the net undepreciated book value of generating plant-in-service ("GPIS"). If the market value of a generating asset is greater than its net GPIS, then there are no stranded costs associated with that asset. Second, because, as discussed below, Revised Code Section 4928.01(A)(28) defined the starting date of competitive retail electric service as January 1, 2001, all generating plant investment subsequent to that date must be recovered from the market, rather than in cost-based rates.[10] Thus, the only legitimate embedded capacity costs AEP Ohio could have recovered as stranded costs were those costs related to generating plant that was in service prior to the start of competitive retail service.

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[9] *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1730-EL-ETP and 99-1731-EL-ETP (the "ETP Proceeding").

[10] S.B. 221 offers a limited opportunity for cost-based rates for post-1-1-2009 capital investment, but this exception is not applicable here.

Q. HOW WERE STRANDED COSTS TO BE RECOVERED UNDER S.B. 3?

A. Under S.B. 3, stranded cost recovery took two forms, which became known as Generation Transition Costs ("GTCs") and Regulatory Transition Costs ("RTCs"). An electric utility could recover GTCs through a transition charge during the transition period, provided the costs satisfied statutory requirements.[11] At the end of the transition period, which was December 31, 2005, unless modified by the Commission as part of a utility's transition plan, S.B. 3 stated that, "the utility shall be fully on its own in the competitive market."[12] Similarly, an electric utility could recover its RTCs both during the transition period and for several years thereafter, but in any case no later than December 31, 2010.[13] For AEP Ohio, the transition period for recovering RTCs ended as of December 31, 2008.[14] Thus, AEP Ohio's ability to recover stranded costs of its generating facilities – meaning, any costs that would not be fully recovered through the competitive market after the transition period – ended almost six years ago for GTCs and almost three years ago for RTCs. As I understand, under the transition provisions of S.B. 3, the PUCO was, and is, prohibited from authorizing "the receipt of transition revenues or any equivalent revenues by an electric utility except as expressly authorized."[15] Moreover, an electric

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[11] R.C. 4928.39 provided for recovery of "just and reasonable transition costs of the utility, which costs the commission finds meet all of the following criteria:

(A) The costs were prudently incurred.

(B) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.

(C) The costs are unrecoverable in a competitive market.

(D) The utility would otherwise be entitled an opportunity to recover the costs."

[12] R.C. 4928.38.

[13] R.C 4928.40.

[14] ETP Proceeding, Stipulation, Attachment 1 (May 8, 2000). Under the Stipulation, CSP could recover its RTCs through December 31, 2008, while OPC could recover its RTCs through December 31, 2007.

[15] R.C. 4928.38.

utility is barred from including any transition costs in an ESP or MRO.[16] Yet, under the proposed ESP, AEP Ohio will be recovering above-market transition costs until June 1, 2015.

In the transition plan proceeding filed by CSP and OPC in 1999, the two companies estimated stranded costs of between $894 million and $953 million.[17] As part of the stipulation approved by the PUCO in that case, CSP and OPC waived the recovery of stranded generation costs through GTCs or other equivalent revenues through any mechanism other than competitive market pricing.[18]

CSP and OPC also agreed that their opportunity to recover RTCs would be limited to $616 million, which CSP would recover over eight years and OPC would recover over seven years, and that this was sufficient to recover all regulatory assets.[19] Thus, as of no later than January 1, 2009, AEP Ohio had committed to recover its sunk costs (as well as its variable costs) only in the competitive market.

Q. WHAT IS THE RELEVANCE OF S.B. 3 TO AEP OHIO'S PROPOSAL TO CHARGE A NEGOTIATED, BUT ABOVE-MARKET, CAPACITY PRICE AS PART OF THE STIPULATION?

A. Because S.B. 3 provided a clear demarcation date between pre-transition and post-transition generation costs, any cost-based capacity charges levied by AEP Ohio could apply only to generating plant that was in-service on or before December 31, 2000, the day before the transition date of January 1, 2001, and only then if AEP Ohio had not waived recovery and/or already fully recovered these costs. Thus, AEP Ohio's claims that the Stipulation benefits

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[16] R.C. 4928.141 ("A standard service offer under section 4928.142 or 4928.143 of the Revised Code shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the utility's rate plan.").

[17] ETP Proceeding, Supplemental Direct Testimony of John H. Landon on Behalf of Columbus Southern Power Company and Ohio Power Company, filed April 18, 2000, at 3.

[18] ETP Proceeding, Opinion and Order at 15-16, 18 (September 28, 2000); ETP Proceeding, Stipulation at pp. 3, 10 (May 8, 2000).

[19] ETP Proceeding, Stipulation at 4, 10 (May 8, 2000).

ratepayers in this proceeding because the proposed RPM set-aside capacity and the $255/MW-day capacity charge are less than the $355.72/MW-day value AEP witness Pearce calculated using a cost-based, formula rate approach based on generating plant in service as of December 31, 2010 – is wrong for three reasons. First, the transition period during which AEP Ohio was allowed to recover stranded generation costs is long over, and AEP Ohio is not entitled to any other cost-based recovery. Second, as I demonstrate below, AEP Ohio has already recovered all of its stranded generation costs. And, third, AEP includes in its capacity charges generating plant investment made by AEP Ohio between January 1, 2001 and December 31, 2010 – ten years' worth of investment that, under S.B. 3, should be recovered only from market-based sales.

Q. WHAT MARKET MECHANISMS CAN AEP OHIO USE TO COLLECT GENERATION CAPACITY COSTS?

A. AEP Ohio can, and has, used the off-system and pool sales it makes every year to recover its capacity costs.[20] Similarly, AEP Ohio can recover, and has recovered, a portion of its capacity costs from sales into the PJM RPM auctions.[21] In addition to these market mechanisms, AEP Ohio also has collected an unknown and, according to AEP Ohio, unknowable portion of its capacity costs for many years through its base generation rates charged to its SSO customers.[22]

Q. HOW DID YOU DETERMINE THE AMOUNT BY WHICH THE NET BOOK VALUE OF AEP OHIO'S GENERATING PLANTS SINCE THE ETP PROCEEDING DECREASED BETWEEN JANUARY 1, 2001 AND DECEMBER 31, 2010?

A. Using the original cost (gross plant) and accumulated depreciation values for generation plant published in CSP's and OPC's respective FERC Form-1 filings, I first determined the net

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[20] *See* Columbus Southern Power Company's and Ohio Power Company's Response to OCC's 4th set INT-136, 139, 140, 143, and OCC 4-143 Attachment 1 (attached as Exhibit JAL-2).

[21] *See* Columbus Southern Power Company's and Ohio Power Company's Response to OCC's 4th set INT-146, 147 (attached as Exhibit JAL-3).

[22] Columbus Southern Power Company's and Ohio Power Company's Response to FES 4th set INT 4-005 (attached as Exhibit JAL-4).

undepreciated GPIS for both companies as of January 1, 2001. I then applied the annual depreciation rates shown in Exhibit JHL-2 of the testimony of AEP Ohio witness John Landon in the ETP Proceeding to calculate the net undepreciated GPIS values for each company as of December 31, 2010. The results of my analysis are shown in Table 3.

Table 3: Reduction in Net Undepreciated GPIS Since 12/31/2000

Line No.	Item	CSP	OPC	TOTAL
[1]	Gross GPIS, December 31, 2000	$1,558,721,963	$2,739,392,759	$4,298,114,722
[2]	Accumulated Depreciation, December 31, 2000	$641,160,834	$1,526,498,824	$2,167,659,658
[3]	Net GPIS, December 31, 2000	$917,561,129	$1,212,893,935	$2,130,455,064
[4]	Generation Plant Depreciation Rate	3.2%	3.4%	3.33%
[5]	Annual Depreciation of 12/31/2000 GPIS	$49,879,103	$93,139,354	$143,018,457
[6]	Reduction in Net GPIS (12/31/2000 - 12/31/2010)	**$498,791,028**	**$931,393,538**	**$1,430,184,566**
[7]	**Remaining GPIS, 12/31/2010**	**$418,770,101**	**$281,500,397**	**$700,270,498**

Notes:

[1] Source: CSP, OPC 2000 FERC Form-1, pp.204-07.

[2] Source: CSP, OPC 2000 FERC Form-1, p. 219.

[3] Equals: [1] - [2]

[4] Source: ETP Proceeding, Landon Supplemental Direct, Revised Exhibit JHL-2.

[5] Equals: [1] x [4]

[6] Equals: - (10 x [5])

[7] Equals: [3] - [6]

Table 3 shows that, using the generation depreciation rates assumed by AEP witness Landon in the ETP proceeding for his calculation of stranded generation costs, an additional $498 million of CSP's GPIS on December 31, 2000 was depreciated through December 31, 2010. Similarly, an additional $931 million of OPC's GPIS on December 31, 2000 was depreciated through December 31, 2010. Thus, as shown on Line [6] of Table 3, over the 10-year period between December 31, 2000 and December 31, 2010, AEP Ohio accrued $1.43 billion of depreciation related to its GPIS as of December 31, 2000 (ignoring all subsequent capital additions that would further add to the overall depreciation accrual). Because stranded generation costs are defined as the difference between the market value of an asset (i.e., the net present value of future generation plant cash flows) and net undepreciated book value, these additional depreciation accruals represent a reduction in the initial estimates of CSP's and OPC's stranded generation costs. In other words, because the remaining undepreciated book value of pre-2001 generating plant investments necessarily decreases over time, so do stranded costs.

Q. HOW WERE THE STRANDED GENERATION COSTS FOR CSP AND OPC ESTIMATED IN THE ETP PROCEEDING?

A. CSP and OPC relied on a revenue-based approach, developed by AEP Ohio witness Landon, in which the net present value of each generating unit was estimated based on forecasts of future market prices and costs over the generating plant's remaining lifetime.[23] AEP Ohio also identified "regulatory assets" as costs that are distinct from stranded costs related to generation assets or the transition to competition. These "regulatory assets" are deferred expenses, including deferred taxes, from which ratepayers have already benefited but which had not been collected only because of past Commission orders and practices.[24]

Q. WHAT IS THE RELATIONSHIP BETWEEN THE EMBEDDED CAPACITY COSTS OF AEP OHIO'S GENERATING UNITS AND THE ESTIMATE OF ITS STRANDED COSTS?

A. The stranded generating cost estimates determined by AEP Ohio witness Landon in the ETP Proceeding for CSP and OPC were based on projections of future generation revenues, less future O&M costs (including fuel), taxes, and insurance, less the generating plants' overall net undepreciated book value as of December 31, 2000. In comparison, the embedded generation costs estimated by AEP Ohio in its capacity cost filing are a one-year snapshot of fixed costs that include a return on the undepreciated value of all of its generating plant, including all generating plant capital investment made on or after January 1, 2001, as of December 31, 2010.

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[23] ETP Proceeding, Direct Testimony of John Landon on behalf of Columbus Southern Power Company and Ohio Power Company, December 30, 1999 ("ETP Landon Direct"), at 25-26.

[24] *Id.* at p. 9.

Q. WHAT WERE THE STRANDED COST ESTIMATES DETERMINED BY MR. LANDON IN THE ETP PROCEEDING?

A. According to Exhibit JHL-2 of Mr. Landon's testimony, he estimated stranded costs of $517.5 million for CSP and $139.4 million for OPC under his "Base Environment, Low Gas" scenario.[25] Under his "High Gas, Alternative Environment" scenario, he estimated stranded costs of $476.7 million and $45.9 million for CSP and OPC, respectively. In Supplemental Direct testimony, Mr. Landon revised these estimates to $539.8 million and $558.7 million for CSP, and $353.8 million and $394.4 million for OPC under Low and High gas price scenarios.[26] The aggregate stranded cost estimate derived by Mr. Landon for AEP Ohio was therefore between $893.6 million and $953.1 million.

Q. BASED ON MR. LANDON'S ESTIMATES, DO YOU CONCLUDE THAT AEP HAS RECOVERED ITS STRANDED GENERATION-RELATED COSTS?

A. Yes. Mr. Landon's highest estimate of stranded generation costs for AEP Ohio was $953.1 million. Because AEP Ohio recovered almost $1.43 billion in depreciation costs between December 31, 2000 and December 31, 2010 for GPIS, as shown in Table 3 above, it is reasonable to conclude that AEP Ohio has fully recovered all stranded generation costs. These depreciation accruals have eliminated from CSP's and OPC's books the stranded costs estimated by Mr. Landon, leaving only costs that are "un-stranded" and, thus, may be recovered through competitive markets at market pricing.

Q. WHAT IS THE SIGNIFICANCE OF YOUR CONCLUSION THAT AEP OHIO HAS RECOVERED ALL OF ITS STRANDED GENERATION COSTS?

A. In addition to the fact that AEP Ohio waived, and is not entitled to receive, any additional recovery of stranded costs, AEP Ohio has no basis for charging CRES customers a negotiated

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[25] ETP Landon Direct at 44:12-14.

[26] ETP Proceeding, Supplemental Direct Testimony of John Landon, April 18, 2000, at 8. For his revised estimates, Mr. Landon assumed only one environmental regulation scenario.

above-market price for capacity or including an above-market price for capacity in its Competitive Benchmark Price, because AEP Ohio has recovered all of its stranded generation costs. Nor does AEP Ohio have any basis for claiming that the Stipulation provides $856 million in present value benefits by not charging customers a $355.72/MW-day claimed full embedded cost for capacity. (As I discuss in Section II.E, below, this value is itself flawed.) In other words, under the Stipulation, AEP Ohio would be allowed to double-recover up to an additional $1.27 billion in present value <u>costs</u> from ratepayers for above-market capacity, costs for which AEP Ohio has no legitimate claim to recover. Therefore, allowing AEP Ohio to recover these costs as part of the proposed ESP would clearly violate the principle that the Stipulation must benefit ratepayers, will allow AEP Ohio to double recover costs, and will be contrary to Ohio's policy towards creating a competitive electric market.

E. <u>AEP Ohio's Formula Rate Estimates of its Capacity Costs are Wrong and Greatly Inflated.</u>

Q. PLEASE EXPLAIN WHY AEP OHIO'S FORMULA RATE CAPACITY COST ESTIMATES THAT IT USES AS A COMPONENT OF THE COMPETITIVE BENCHMARK PRICE ARE INCORRECT.

A. As explained above, AEP Ohio uses a formula rate to calculate what it alleges is a cost-based revenue requirement for the fixed costs of AEP Ohio's generating units. There are two reasons why AEP Ohio's capacity cost estimates, as shown in Exhibits KDP-1 and KDP-2, are incorrect and greatly inflated. First, AEP Ohio's formula rate capacity cost estimates wrongly double-recover capacity costs, because they fail to include the contributions to embedded capacity costs from <u>energy-related</u> sales for resale. In other words, in setting the formula rate capacity costs, AEP Ohio keeps all of the profits from its energy-related sales. Second, even if, *arguendo*, one accepted AEP Ohio's contention that it is entitled to levy a formula rate-based capacity charge, then the formula rate estimate should reflect only generating plant investment that was in-service prior to the January 1, 2001 transition date. As such, it is necessary to adjust the rate base, return on rate base, depreciation expense, and income tax values in AEP Ohio's capacity cost filing to reflect only pre-transition date generating plant.

Q. PLEASE EXPLAIN WHY FIXED COSTS RECOVERED FROM ENERGY-RELATED SALES FOR RESALE MUST ALSO BE SUBTRACTED FROM AEP OHIO'S CAPACITY COST ESTIMATE?

A. In its formula rate estimates of 2010 capacity costs, AEP Ohio subtracts out only those revenues from capacity-specific sales for resale. AEP Ohio ignores the fact that it also recovers a portion of its fixed costs when it makes energy-related sales for resale because revenues received from those sales that exceed AEP Ohio's variable O&M plus fuel costs recover a portion of its embedded capacity costs. Thus, AEP Ohio has established a formula rate to recover all of its embedded costs. However, when AEP Ohio makes energy-related sales, the profits from those sales help recover those same embedded costs, and provide an additional return on embedded rate base. Thus, AEP Ohio recovers a portion of its embedded costs twice: first, through its embedded capacity cost and second through off-system energy sales. Regardless of whether AEP Ohio's assumption that it is entitled to recover its full embedded costs is valid, the company is clearly <u>not</u> allowed to double recover those costs. Such an outcome is incompatible with basic rate regulation. Thus, AEP Ohio is required to subtract all revenues from sales for resale that contribute to the recovery of embedded generation capacity costs.

Q. HOW DO YOU ESTIMATE THE CONTRIBUTION TO EMBEDDED CAPACITY COSTS FROM ENERGY SALES FOR RESALE?

A. All of the revenues from energy sales for resale that exceed variable (or marginal) costs contribute to embedded costs by definition. For example, suppose that AEP Ohio's energy revenues from energy sales for resale total $200 million more than total fuel and variable O&M expenses recorded for these sales. In that case, AEP Ohio has now earned $200 million of profits that also recover its embedded capacity costs and contribute to its return on rate base. If AEP Ohio does not subtract this $200 million profits from energy-related sales from its formula rate capacity cost estimate, the company's "Annual Production Cost" estimates, which are what AEP Ohio uses to set the capacity prices that it proposes to use to charge customers for PJM-related capacity costs, will be overstated by $200 million. Thus, I have estimated the actual profits from energy-related sales for resale made by AEP Ohio in 2010, using the CSP and OPC 2010 FERC Form-1 Reports.

Q. WHAT REVENUES DID AEP OHIO EARN FROM ENERGY-RELATED SALES FOR RESALE IN 2010?

A. According to data published in CSP's and OPC's respective FERC Form-1 filings for 2010, the revenues from CSP's total non-requirements ("non-RQ") energy-related sales for resale were $295,218,916.[27] OPC's revenues from energy-related sales for resale were $778,113,468.[28] The difference between these revenues and each utility's respective variable O&M and fuel costs associated with those off-system energy-related sales represents dollars that, by definition, recover embedded generating costs and provide AEP Ohio with an additional return on that capacity investment.

Q DOES THE FORMULA RATE INCLUDE AN ALLOWED RETURN ON RATE BASE?

A. Yes. Thus, suppose AEP Ohio did not sell any of the energy generated by its generating resources, and only sold capacity. In that case, the $355.72/MW-day formula rate value estimated by Dr. Pearce would provide AEP with an allowed 11.15% return on equity and an overall 8.62% return on capital investment for OPC generating resources.[29] By retaining all or a portion of the profits from energy sales, AEP Ohio's realized return on equity and actual return on investment will be higher than the 11.15% allowed return in the formula rate.

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[27] Source: CSP FERC Form-1 2010, p. 311, and Exhibit KDP-3, page 4, line 6.

[28] Source: OPC FERC Form-1 2010, p. 311, and Exhibit KDP-4, page 4, line 6.

[29] *See* Exhibit KDP-2, page 11. For CSP, the return on investment is shown as 8.63% because of a slight difference in capital structure. *See* Exhibit KDP-1, page 11.

Q. WHY IS EARNING A HIGHER RETURN PROBLEMATIC?

A. The 11.15% return on equity and 8.62% presumably are set on the basis of risk-comparability. For regulated firms, that is a long-standing requirement.[30] What this means is that a regulated firm, such as an electric utility, is allowed to earn a return on its investment that is comparable to other firms facing the same level of business and financial risks. Under AEP Ohio's proposed formula rate, which allows for that comparable return plus additional revenues not counted by the formula, the company essentially has guaranteed itself an above-market return. Moreover, as I discuss below, AEP Ohio is also seeking to recover costs of resources that it previously agreed <u>not</u> to collect as part of the original transition to competition that began on January 1, 2001. Again, therefore, equating a "benefit" to CRES customers from not recovering monies for which it has no right to collect in the first place, is specious. One might as well argue that the thief who stole your wallet, but not your watch, "benefitted" you, because he could have stolen the watch, too.

Q. HAVE YOU ESTIMATED THE REVENUES FROM ENERGY-RELATED SALES FOR RESALE THAT CONTRIBUTED TO AEP OHIO'S EMBEDDED GENERATION COSTS?

A. Yes. The details of my calculations for CSP and OPC are shown in Table 5, below. For each company, I began by determining the total variable costs associated with its power production expenses, using the FERC accounts shown in Table 4, which are the accounts AEP Ohio classifies as variable costs.[31]

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[30] *Federal Power Comm'n. v Hope Natural Gas Co*., 323 U.S. 591 (1944).

[31] *See* Exhibit KDP-1, page 15.

Table 4: FERC Energy-Related Power Production Expense Accounts

FERC Account	Account Description
Steam Power Generation	
501	Fuel
503	Steam from Other Sources
504	Steam Transfers (credit)
509	Emissions Allowances
510	Maintenance Supervision and Engineering
512	Maintenance of Boiler Plant
513	Maintenance of Electric Plant
Hydraulic Power Generation	
544	Maintenance of Electric Plant
Other Power Generation	
547	Fuel

Using the CSP's and OPC's FERC Form-1 filings for the year ended December 31, 2010, I determined total energy-related power production expenses. I then determined an average energy-related cost/MWh of generation, based on reported total generation, as shown in the Electric Energy Accounts, page 401a of each company's FERC Form-1. Using this value as the energy-only cost per MWh, I then calculated total energy-related power production expenses associated with sales for resale, based on the total non-requirement energy-related sales for resale, as recorded in Account No. 447. I then subtracted this value from the energy sales revenues reported by AEP Ohio for CSP and OPC in Exhibits KDP-1 and KDP-2. Because two of CSP's generating plants—Waterford and Darby—were constructed after the January 1, 2001 transition date, I adjusted the net contribution to embedded costs from energy sales from these plants. In that way, my revised capacity cost estimate is consistent with incorporating only pre-transition GPIS.

Using this approach, and as shown in more detail in Table 5 below, I estimated that CSP's pre-2001 generating plants contributed $75,234,340 towards recovery of embedded costs, and that OPC's generating plants contributed $176,771,506 towards recovery of embedded costs, or $252,005,846 of embedded cost recovery in the aggregate, for which AEP Ohio would double-recover by charging its reported embedded cost capacity value. Because AEP Ohio is clearly not allowed to double-recover embedded costs, it is wrong to claim that ratepayers "benefit" if AEP Ohio does not do so.

Table 5: Contribution to Embedded Capacity Costs from Energy Sales for Resale (2010)

Line No.	Type	FERC Account	CSP	OPC	TOTAL
	Steam Power Generation				
[1]	501	Fuel	$ 367,086,593	$ 992,562,492	$ 1,359,649,085
[2]	503	Steam from Other Sources	$ -	$ -	$ -
[3]	504	Steam Transfers (credit)	$ -	$ -	$ -
[4]	509	Emissions Allowances	$ 5,727,736	$ 8,473,508	$ 14,201,244
[5]	510	Maintenance Supervision and Engineering	$ 2,327,198	$ 12,473,218	$ 14,800,416
[6]	512	Maintenance of Boiler Plant	$ 44,791,005	$ 107,219,065	$ 152,010,070
[7]	513	Maintenance of Electric Plant	$ 7,662,253	$ 22,984,446	$ 30,646,699
	Hydraulic Power Generation				
[8]	544	Maintenance of Electric Plant	$ -	$ 2,051,934	$ 2,051,934
	Other Power Generation				
[9]	547	Fuel	$ 2,928,243	$ -	$ 2,928,243
[10]	**Total Energy-related Production Costs**		**$ 430,523,028**	**$ 1,145,764,663**	**$ 1,576,287,691**
[11]	**Total Power Production (MWh)**		12,521,147	48,768,500	$ 61,289,647
[12]	*Power production - post-2001 GPIS (MWh)*		641,627	-	641,627
[13]	**Net pre-2001 GPIS power production (MWh)**		**11,879,520**	**48,768,500**	**60,648,020**
[14]	**Average energy-only production costs ($/ MWh)**		$ 34.3837	$ 23.4939	$ 25.7187
[15]	**Total Reported Energy Sales for Resale (MWh)**		6,397,937	25,595,610	$ 31,993,547
[16]	**Estimated Variable Production Costs, Sales for Resale**		$ 219,984,576	$ 601,341,962	$ 821,326,538
[17]	**Total Reported Energy-related Revenues from Sales for Resale**		$ 295,218,916	$ 778,113,468	$ 1,073,332,384
[18]	**Net Contribution to Embedded Generation Costs**		**$ 75,234,340**	**$ 176,771,506**	**$ 252,005,846**
[19]	**Adjustment for post-2001 GPIS production**		**$ 3,855,269**	**$ -**	**$ 3,855,269**
[20]	**Net Contribution to Embedded Generation Costs, pre-2001 GPIS**		**$ 71,379,072**	**$ 176,771,506**	**$ 248,150,578**

Notes:

[1] Source: 2010 FERC Form-1 Report, pp. 320-21.
[2] Source: Table 5, line 20.
[3] Source: 2010 FERC Form-1 Report, pp. 320-21.
[4] Source: 2010 FERC Form-1 Report, pp. 320-21.
[5] Source: 2010 FERC Form-1 Report, pp. 320-21.
[6] Source: 2010 FERC Form-1 Report, pp. 320-21.
[7] Source: 2010 FERC Form-1 Report, pp. 320-21.
[8] Source: 2010 FERC Form-1 Report, pp. 320-21.
[9] Source: 2010 FERC Form-1 Report, pp. 320-21.
[10] Equals: [1] + [2] + ... + [9].
[11] Source: 2010 FERC Form-1 Report, p. 401a.
[12] Source: 2010 FERC Form-1 Report, p. 403.1.
[13] Equals: [11] - [12].
[14] Equals: [10] / [11].
[15] Source: 2010 FERC Form-1 Report, p. 311. (Non-requirements only)
[16] Equals: [14] x [15].
[17] Source: 2010 FERC Form-1 Report, p. 311. (Non-requirements only)
[18] Equals: [17] - [16].
[19] Equals: ([12] / [11]) x [18].
[20] Equals: [18] - [19].

Q. PLEASE DESCRIBE HOW YOU REVISED AEP OHIO'S FORMULA RATE ESTIMATE OF ITS CAPACITY COSTS TO ACCOUNT FOR PRE-2001 GENERATING PLANT.

A. In addition to correcting for double-recovery of embedded generation costs, I recalculated the capacity cost based on depreciation for pre-2001 GPIS only. I also accounted for the additional depreciation of existing generating plant that was in service on January 1, 2001 to determine the net undepreciated value of that generating plant as of December 31, 2010, because it is the undepreciated value that determines the "rate base," and return on that rate base.[32] I then adjusted the income tax payments because, with a lower return on rate base, the income tax paid on that return would also decrease. Finally, I adjusted the investment tax credit CSP and OPC receive.

Q. WHAT ARE YOUR REVISED CAPACITY COST ESTIMATES FOR CSP AND OPC?

A. The revised capacity cost estimates I calculate are shown in Table 6. As can be seen, the resulting capacity cost estimate for CSP is $179.60/MW-day. The estimate for OPC is ($44.88)/MW-day, which means that OPC's revenues from off-system capacity and energy sales are greater than its remaining embedded capacity costs. The overall average embedded capacity cost value for AEP Ohio is $57.35/MW-day, which is slightly lower than the $63.22/MW-day average of the PJM RPM market-clearing prices for the period January 2012 – May 2015. It is that $57.35/MW-day amount ($59.31/MW-day including AEP Ohio's 3.4126% loss factor) that AEP Ohio is entitled to receive under a formula rate, not $355.72/MW-day as Dr. Pearce estimates.

[32] To be conservative, I did not further reduce the value of AEP Ohio's net undepreciated generating assets as of December 31, 2000 by ADIT, which is far larger than cash working capital. For example, Page 6 of Exhibits KDP-1 and KDP-2 shows that ADIT was $352.8 million for CSP and $914.8 million for OPC. Page 5 of Exhibits KDP-1 and KDP-2 shows that the demand-related cash working capital amounts for the two companies was $13.9 million and $34.9 million, respectively.

Table 6: Revised Embedded Capacity Cost Estimates

Line No.	Item	CSP	OPC	TOTAL
[1]	Annual Production Fixed Cost, as Reported	$477,093,822	$660,504,310	**$1,137,598,132**
[2]	(Energy-only contribution to embedded costs adjustment)	($71,379,072)	($176,771,506)	**($248,150,578)**
	Depreciation Expense Adjustment			
[3]	*Depreciation Expense , as Reported*	$59,590,281	$256,957,852	**$316,548,133**
[4]	*Annual Depreciation Expense, GPIS 12/31/2000*	$49,879,103	$93,139,354	**$143,018,457**
[5]	***Calculated Depreciation Rate Adjustment***	***($9,711,178)***	***($163,818,498)***	***($173,529,676)***
	Return on Rate Base Adjustment			
[6]	*Return on Rate Base, as Reported*	$129,071,540	$311,327,830	**$440,399,370**
[7]	*Allowed Return*	8.63%	8.62%	
[8]	*Return on Net GPIS 12/31/2000, as of 12/31/2010*	$36,139,860	$24,265,334	**$60,405,194**
[9]	***Calculated Return on Rate Base Adjustment***	***($92,931,680)***	***($287,062,496)***	***($379,994,176)***
	Income Tax Adjustment			
[10]	*Income Tax Expense , as Reported*	$45,891,012	$123,339,938	**$169,230,950**
[11]	*ITC, as Reported*	($1,658,786)	($407,172)	**($2,065,958)**
[12]	*Income Tax Rate*	36.8399%	39.7482%	
[13]	*Income Tax on Adjusted Return on Rate Base*	$13,313,888	$9,645,034	**$22,958,922**
[14]	*ITC, Revised Based on 12/31/2000 GPIS*	($1,658,786)	($407,172)	($2,065,958)
[15]	***Calculated Income Tax Adjustment***	***($32,577,124)***	***($113,694,904)***	***($146,272,028)***
[16]	**Total Adjustments to Annual Production Cost, as Reported**	**($206,599,054)**	**($741,347,405)**	**($947,946,459)**
[17]	**Revised Annual Production Costs**	**$270,494,768**	**($80,843,095)**	**$189,651,673**
[18]	5 CP Coincident Peak Demand (MW)	4,126.2	4,934.6	9,060.8
[19]	**Revised Daily Capacity Cost ($/MW-day)**	**$179.60**	**($44.88)**	**$57.35**

Notes:

[1] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[2] Source: Table 5, line 20.
[3] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[4] Source: Table 3, line 5.
[5] Equals: [4] - [3].
[6] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[7] Source: Exhibit KDP-3, p. 5 and KDP-4, p. 5.
[8] Equals: [Table 3, line 7] x [7].
[9] Equals: [8] - [6].
[10] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[11] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[12] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[13] Equals: [12] x [8].
[14] No material change to ITC estimate.
[15] Equals: {[13] - [10] } + {[14] - [11]}.
[16] Equals: [2] + [5] + [9] + [15].
[17] Equals: [1] + [16]
[18] Source: Exhibit KDP-3, p. 2 and KDP-4, p. 2.
[19] Equals: [17] / [18] / 365.

Q. HOW DOES YOUR AVERAGE CAPACITY VALUE OF $57.35/MW-DAY RECONCILE WITH MR. SCHNITZER'S "MAXIMUM ABOVE-MARKET" CAPACITY PRICE?

A. Mr. Schnitzer estimates a "maximum above-market" capacity price of $162/MW-day based on a 2010 test year. Mr. Schnitzer arrived at this price by subtracting out energy and ancillary service revenues from AEP Ohio's formula rate and cost information, just as PJM does to determine the cost of new entry ("CONE") for a hypothetical generating facility and as the Independent Market Monitor ("IMM") does to determine the maximum prices at which individual generating units can be offered into the RPM, but does not include additional, required adjustments I make here. Whereas the capacity price I show above reflects a necessary reduction in AEP Ohio's inflated capacity cost estimate, Mr. Schnitzer's "maximum above-market" price represents the maximum price that AEP Ohio could charge for capacity without double-recovering generation costs it recoups elsewhere.

Q. CAN YOU SUMMARIZE YOUR OVERALL CONCLUSIONS REGARDING THE $255/MW-DAY CAPACITY PRICE FOR THE STIPULATION, WHICH IS ALSO USED BY AEP OHIO WITNESS THOMAS TO PERFORM HER ESP V. MRO TEST?

A. Yes. First, because AEP Ohio agreed to forego guaranteed recovery of its stranded generation costs, the MRO-ESP price comparison shown in Exhibit LJT-2 should be based solely on "market prices" that base the capacity prices on the PJM RPM market-clearing prices. Thus, even if one were to accept, *arguendo*, the other components of AEP Ohio witness Thomas's market price build-up, the appropriate market prices would be those shown on page 2 of Exhibit LJT-1. Second, my analysis shows that, even if AEP Ohio had not agreed to forego recovery of stranded generation costs, it has recovered all of those costs over the 10-year period between December 31, 2000 and December 31, 2010.[33] Again, therefore, AEP Ohio should charge a market price for capacity. Third, even if, *arguendo*, AEP Ohio could charge an embedded cost-based rate for capacity using a formula rate approach, that cost should not allow AEP Ohio to double-recover energy sales revenues that offset embedded costs and should reflect only capacity costs associated with pre-transition generating resources (*i.e.*, those in-service before January 1, 2001). I calculate an average capacity cost for those resources of $57.35/MW-day, which is

[33] *See* Table 3, above, and discussion thereafter.

slightly lower than the average RPM market-clearing price for capacity over the term of the proposed ESP and almost five times lower than the $255/MW-day capacity price in the Stipulation.

III. AEP OHIO'S RATE DESIGN UNDER THE PROPOSED ESP IS UNREASONABLE AND ANTICOMPETITIVE.

Q. WHAT SPECIFIC ASPECTS OF AEP OHIO'S RATE DESIGN DO YOU ADDRESS IN THIS SECTION?

A. In this section, I address three primary issues. First, I address the proposed "market-based" allocation of costs to the different rate classes, which I conclude is not market-based and forecloses competition. Second, I address the proposed nonbypassable Market Transition Rider ("MTR"), which AEP Ohio proposes as a way to mitigate rate increases for certain customers, which also forecloses competition. Third, I address the proposed nonbypassable Generation Resource Rider ("GRR"), which AEP Ohio proposes to use to recover the costs of constructing and operating generating facilities it plans to develop, including the Turning Point solar facility and a new combined-cycle generating plant, Muskingum River 6, to replace the Muskingum River 5 coal-fired unit, which AEP Ohio intends to retire.

A. Based on AEP Ohio's Claimed Embedded Costs, the Base Generation Rate reflects an Artificial Subsidy for SSO Customers.

Q. WHAT IS THE PURPOSE OF THE GSR?

A. AEP Ohio states that the Standard Offer Generation Service Rider ("GSR") includes all base generation charges from its Standard Service Offer tariffs. It will apply to all non-shopping customers.[34] The GSR lists the summer and winter rates paid by each customer class for "base" generation, which, in the aggregate, equate to the Base Generation Rate or "g."

Q. IS THE BASE GENERATION RATE "G" INTENDED TO RECOVER AEP OHIO'S NON-FUEL GENERATING COSTS?

A. Yes. In the ESP Proceeding that led to the Stipulation, AEP Ohio witness Roush stated that he "hoped" the base generation rate would recover the company's generation costs.[35] However, he explained that he could not say what the capacity price is that would be charged to SSO customers under the proposed ESP.[36] He also could not identify what portion of revenue from the GSR goes to capacity, what portion goes to energy, and what portion goes to ancillary services.[37] He did, however, agree that if energy and ancillary services revenues could be determined, the remainder would be what AEP Ohio is charging SSO customers for capacity.[38]

Q. IS THE GSR "BUILT UP" FROM BASE GENERATION COSTS, FUEL COSTS, AND ENVIRONMENTAL CARRYING COSTS?

A. No, just the opposite. According to AEP Ohio witness Roush, the GSR was developed by first determining "the market-based price relationships for various types of customer usage"[39] using the methodology developed by AEP Ohio witness Thomas. Next, Mr. Roush states that "the proposed total generation rates were designed to produce average generation prices consistent with the Stipulation."[40]

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[34] Direct testimony of David M. Roush in support of the Stipulation and Recommendation on behalf of Columbus Southern Power Company and Ohio Power Company, September 13, 2011 ("Roush Testimony") at 5:15-19.

[35] Deposition of David M. Roush, August 5, 2011, at 42.

[36] *Id.* at 43.

[37] *Id.* at 44.

[38] *Id.* at p. 45.

[39] Roush Testimony at 8:10-11.

[40] *Id*. at 8:13-15. The actual rates are set forth in Section IV.1.f of the Stipulation. The detailed breakdown of these rates by customer class is shown in Exhibit DMR-1.

Q. WHAT RELATIONSHIP DOES THE GSR HAVE TO THE PRICE-TO-COMPARE ("PTC")?

A. In the Proposed Stipulation, the GSR charge, plus charges imposed under the Fuel Adjustment Clause Rider ("FAC"), establish the PTC for each customer class. (The FAC also currently includes costs for alternative energy compliance. However, under the Stipulation, AEP Ohio will develop a separate, bypassable Alternative Energy Rider ("AER")). In order for a customer to save money through shopping, a CRES supplier's rate has to be lower than the PTC over time. Thus, the level at which AEP Ohio fixes its GSR can have a substantial impact on competition in AEP Ohio's service territory.

Q. IS THE GSR COST-BASED?

A. No, it is not. As discussed above, AEP Ohio witness Roush states that the GSR is designed so that, upon subtracting out AEP Ohio's FAC charge, the base generation rate equals that set in the Stipulation. Under the Stipulation, the basis for how that base generation rate was set is not known. AEP Ohio should have to demonstrate that the GSR is not set so as to unfairly harm market competition.

Q. WHY DOES KNOWING HOW THE BASE GENERATION RATE IS SET MATTER FOR PURPOSES OF APPROVING THE ESP?

A. Although there is no requirement that SSO pricing be cost-based or market-based, rates under an ESP cannot be set in a way that unfairly restricts or forecloses competition. However, if one believes the embedded capacity cost values developed by AEP witness Pearce, this is exactly what the Stipulation will do. The Stipulation sets the base generation rates in each year. Based on forecast non-shopping loads for each year of the ESP, AEP Ohio will then recover those base generation costs from the different customer classes based on its arbitrary determination of "market price" relationships. The result of this is that residential customers, who are least likely to take service from CRES providers, face significant rate increases, whereas commercial and industrial customers, who are more likely to shop, will see lower rates.

Q. HOW DOES AEP OHIO'S OWN ESTIMATE OF ITS CAPACITY AND ANCILLARY SERVICE COSTS COMPARE WITH THE PROPOSED 2012 BASE GENERATION REVENUES?

A. According to the workpapers of AEP Ohio witness Roush, AEP Ohio's current base generation revenues are $914,297,892. The 2012 base generation rates under the Stipulation will recover revenues of $1,065,819,564 for AEP Ohio, of which $459,376,746 will be recovered from CSP customers and $606,442,819 will be recovered from OPC customers.[41]

Based on the full capacity cost charge shown in Exhibit LJT-1, the amount of embedded capacity cost for non-shopping customers would otherwise be $949,093,471, as shown in Table 7. As this table shows, subtracting out AEP Ohio's embedded capacity costs and ancillary service costs leaves a remainder of $90,623,993 of energy-related production costs to be recovered from non-shopping customers (line [8]). Based on AEP Ohio's forecast of non-shopping loads, this equates to an overall average revenue recovery of $2.08/MWh. However, the allocation of that revenue recovery is highly skewed, with residential customers paying $3.29/MWh, or almost 10 times the $0.34/MWh to be paid by commercial customers.

[41] Roush Workpapers, "Stipulation Exhibit 1 to 5 and Workpapers.xls," worksheets CSP E-4 and OPC E-4.

Table 7: Non-Shopping Sales and Recovery of AEP Ohio Base Generation Costs

Line	AEP Ohio	Residential	Commercial	Industrial	Total
[1]	Non-Shopping Load (MWh)	14,831,500	10,472,700	18,199,300	43,503,500
[2]	Capacity Charge ($/MWh)	$28.17	$22.77	$16.09	$21.82
[3]	***Non-Shopping Embedded Capacity Costs***	***$417,803,355***	***$238,463,379***	***$292,826,737***	***$949,093,471***
[4]	Ancillary Service Cost ($/MWh)	$0.60	$0.60	$0.60	$0.60
[5]	***Non-Shopping Ancillary Service Costs***	***$8,898,900***	***$6,283,620***	***$10,919,580***	***$26,102,100***
[6]	***Subtotal Contribution to Base Generation Revenues***	***$426,702,255***	***$244,746,999***	***$303,746,317***	***$975,195,571***
[7]	Total 2012 Base Generation Revenues	$475,570,529	$248,352,169	$341,896,867	$1,065,819,564
[8]	Net Remaining BGR Revenues	$48,868,274	$3,605,170	$38,150,550	$90,623,993
[9]	Net Remaining BGR revenues ($/MWh)	$3.29	$0.34	$2.10	$2.08

Notes

[1] Source: Roush workpapers, tab: '2012 Market G'.
[2] Source: Thomas Exhibit LJT-1, page 3.
[3] Equals [1] x [2].
[4] Source: Thomas Exhibit LJT-1, page 3.
[5] Equals [1] x [4].
[6] Equals [3] + [5].
[7] Source: Roush workpapers, tab: '2012 Market G'.
[8] Equals [7] - [6].
[9] Equals [8] / [1].

Q. HAVE YOU CALCULATED THE NON-FUEL ENERGY-RELATED PRODUCTION COSTS FOR AEP OHIO?

A. Yes. To make this calculation, I used data from AEP Ohio witness Pearce's Exhibits KDP-1 and KDP-2. In theory, after subtracting the profits (margins) on off-system energy sales, the remaining non-fuel energy-related production costs would be recovered from non-shopping customers. AEP Ohio would not recover these energy-related production costs from shopping customers because those customers are not purchasing any energy from AEP Ohio.

The energy-related production costs can be determined using the basic revenue requirement formula shown previously on page 14. Thus, the total non-fuel, energy-related production costs equals the sum of energy-related O&M costs, energy-related A&G costs, energy-related depreciation expense, energy-related income taxes, energy-related return on rate base, and energy-related other taxes. These amounts are shown in Table 8.

Table 8: AEP Net Non-fuel Energy Costs (Excludes Purchased Power Costs)

Line	Item	CSP	OPC	AEP Ohio
[1]	Non-fuel energy O&M costs	$60,508,192	$153,202,171	$213,710,363
[2]	Energy-related A&G costs	$7,279,224	$25,231,894	$32,511,118
[3]	Energy-related General Plant Depreciation	$1,412,084	$4,647,135	$6,059,219
[4]	Energy-related Income Taxes	$2,650,258	$5,132,890	$7,783,148
[5]	Energy-related Return on Ratebase	$7,221,252	$12,922,739	$20,143,990
[6]	**Total Non-fuel, Energy-related Costs (excl. PP costs)**	**$79,071,009**	**$201,136,828**	**$280,207,837**
[7]	Total Generation (MWh)	12,521,147	48,768,500	61,289,647
[8]	Net Margins, energy-only off system sales	$68,521,068	$69,129,989	$137,651,058
[9]	Net Recoverable Non-fuel Energy-related Costs	**$10,549,941**	**$132,006,839**	**$142,556,780**
[10]	Energy sales for resale	6,397,937	25,595,610	31,993,547
[11]	Net own-use generation	6,123,210	23,172,890	29,296,100
[12]	Average Non-fuel, Energy-Related Cost ($/non-resold MWh)	$1.72	$5.70	$4.87

Notes

[1] Source: Exhibits KDP-1 and KDP-2, page 8, line 4.
[2] Source: Exhibits KDP-1 and KDP-2, page 8, line 5.
[3] Source: Exhibits KDP-1 and KDP-2, page 16, line 11.
[4] Source: Exhibits KDP-1 and KDP-2, page 18, line 5.
[5] Source: Exhibits KDP-1 and KDP-2, page 5, line 19.
[6] Equals: $\sum$ [1] … [5].
[7] Source: 2010 FERC CSP & OPC Form-1 Reports, p. 401a
[8] Source: Exhibits KDP-1 and KDP-2, workpapers "Input", line 321.
[9] Equals: [6] - [8].
[10] Source: 2010 FERC CSP & OPC Form-1 Reports, p.311 (non-reqts sales)
[11] Equals: [7] - [10].
[12] Equals: [9] / [11].

As line [6] of Table 8 shows, CSP's net non-fuel energy-related costs, excluding all purchase-power costs (which are recovered through the FAC rider), were $79,071,009 in 2010. Similarly, OPC's costs were $201,136,828. Thus, total non-fuel energy-related costs for AEP Ohio were $280,207,837. Next, I subtract the net profit margins on the two companies' off-system energy sales, which total $137,651,058. The remaining $142,556,780 is the net, energy-related production cost that would need to be recovered from AEP Ohio customers. However, as shown in Table 7, net remaining base generation revenues, after subtracting AEP Ohio's own estimate of its embedded capacity cost and its own estimate of the cost of ancillary services, are only $90,623,993. Thus, either AEP Ohio's remaining energy-related production costs are either over $50 million greater than the amount it intends to recover in 2012 through the proposed base generation rates for each customer class or AEP Ohio's capacity costs are much less than claimed. If the former is true, then AEP Ohio is providing an artificial and anticompetitive subsidy to SSO customers. Charging a lower capacity price to SSO customers than to CRES providers would mean AEP Ohio is foreclosing competition by artificially biasing comparisons between SSO prices and market prices.

Of course, as I have previously demonstrated, AEP Ohio's embedded capacity cost charge, as developed by AEP Ohio witness Pearce, double recovers stranded costs it previously had agreed to forego recovering except in the market. Moreover, Dr. Pearce's estimates wrongly exclude the contribution to embedded costs from the profits associated with off-system energy sales. Thus, in reality, AEP Ohio is unlikely to be subsidizing SSO customers.

B. AEP Ohio's Proposed "Market-Based" Cost Allocation is Flawed

Q. DOES AEP OHIO PROPOSE TO INCREASE BASE GENERATION REVENUES BY EQUAL PERCENTAGES FOR CSP AND OPC CUSTOMERS?

A. No. As shown in Table 9, AEP proposes to increase base generation revenues in 2012 from current levels by 30% for CSP customers and 8% for OPC customers.

Table 9: Change in Base Generation Revenues

Line	Item		CSP		OPC		Total AEP Ohio
[1]	**Current Revenues**	$	353,167,957	$	561,129,845	$	914,297,802
[2]	**Proposed 2012 Revenues**	$	459,376,746	$	606,442,819	$	1,065,819,564
[3]	**Difference**	$	106,208,789	$	45,312,974	$	151,521,762
[4]	**Pct Change**		30.07%		8.08%		16.57%

Notes:

[1] Source: Roush Workpapers, Worksheets CSP-4 and OPC-4.

[2] Source: Roush Workpapers, Worksheets CSP-4 and OPC-4.

[3] Equals [2] - [1].

[4] Equals { [3] / [1] } - 1.0

Q. ARE THESE INCREASED REVENUES REFLECTED IN SIMILAR CHANGES IN THE BASE GENERATION RATE CHANGES FOR EACH CUSTOMER CLASS?

A. No. The percentage changes in the base generation rates for each major customer class are shown in Table 10.

Table 10: Change in Base Generation Revenues – Major Rate Classes

Company/Rate Class	Current Base Rates	Proposed 2012	Difference	Pct Change
		CSP		
RR	$132,159,493	$208,732,621	$76,573,128	57.9%
GS-2	$45,420,946	$27,049,906	($18,371,040)	-40.4%
GS-3	$69,593,005	$70,160,966	$567,961	0.8%
GS-4/IRP-D	$34,820,356	$71,427,644	$36,607,288	105.1%
		OPC		
RS	$176,778,209	$234,297,187	$57,518,978	32.5%
GS-2	$79,145,141	$69,482,254	($9,662,887)	-12.2%
GS-3	$55,780,599	$60,903,688	$5,123,089	9.2%
GS-4/IRP-D	$84,060,456	$83,281,164	($779,292)	-0.9%

Source: Roush Workpapers, Worksheets CSP-4 and OPC-4

As can be seen in Table 10, AEP Ohio proposes to increase base generation revenues allocated to residential customers of CSP by almost 58%, and increase the allocation of base generation revenues to CSP residential customers by almost 33%. On the other hand, revenues allocated to GS-2 (Commercial) will decrease by over 40% for CSP customers and over 12% for OPC customers. Perhaps the strangest of all is that, for CSP, base generation revenues allocated to GS-4/IRP-D customers increase 105%, while GS-4/IRP-D customers of OPC see their allocation decrease by about 1%.

The proposed allocations of base generation revenues to the different rate classes defy any cost-based explanation. Instead, other than the incongruous increase in the base generation costs allocated to CSP's GS-4/IRP-D customers, it appears to be an attempt by AEP to foreclose market competition by reducing costs allocated to the large commercial and industrial customers who are most likely to switch to competitive electric suppliers, while increasing costs to residential customers who are least likely to switch.

Q. HAVE YOU IDENTIFIED ANY OTHER RATE DESIGN ISSUES WITH THE GSR?

A. Yes. AEP Ohio does not intend to allocate the costs of the GSR to different rate classes based on traditional ratemaking principles. According to AEP Ohio witness Roush, the company's rates, "reflect an amalgamation of very old cost relationships, including any historical levels of cross-subsidization among tariff classes."[42] Mr. Roush testifies that "the design of the Stipulated base generation prices rationalizes the rate relationships based upon the manner in which the market would price such loads using the same methodology used by Company witness Thomas to develop the competitive benchmark price and applying it to the class load shapes."[43]

What this means is that AEP Ohio established the relative rates customers in different rate classes should be charged based on AEP Ohio witness Thomas's "methodology" for estimating the competitive benchmark price. For example, Ms. Thomas determined that the average residential "market price" in 2012 should be 11% greater than the average commercial "market price," and 22% greater than the average industrial "market price," based on the stipulated capacity price of $255/MW-day.[44]

A fundamental flaw in Ms. Thomas's approach, however, is that the "market price relationships" she derives change, depending on the assumed capacity price. For example, if Ms. Thomas's "market prices" are based on the actual RPM market-clearing capacity prices, she concludes that the average residential "market price" in 2012 should be just 6% higher than the commercial "market price," and just under 12% higher than the industrial price. For the period June 2014 - May 2015, however, the residential "market price" should be 9% higher than the

[42] Roush Testimony at 9:9-11.

[43] *Id*. at 9:18-22.

[44] Exhibit LJT-1.

commercial "market price" and 15% higher than the industrial "market price." These changing relative "market prices" make no economic sense, and Ms. Thomas provides no explanation as to why "the market" as Mr. Roush refers to it, will change the relative pricing of energy depending on the price of capacity. Ms. Thomas offers no reasons why, if customers are to be charged rates that reflect market conditions, the relationships will change over time depending on the level of capacity prices assumed.

Q. DO YOU CONSIDER THE METHODOLOGY USED BY MS. THOMAS TO DEVELOP RELATIVE PRICES BY RATE CLASS A VALID METHODOLOGY FOR MR. ROUSH TO USE TO ALLOCATE COSTS BETWEEN RATE CLASSES?

A. No. The methodology used by Ms. Thomas to determine "benchmark" market prices by customer class suffers from irreparable methodological and data flaws, as discussed in Mr. Schnitzer's testimony. Because the resulting relative rates for Residential, Commercial, and Industrial customers are arbitrary, there is no rational basis for Mr. Roush to use these relative rates to allocate generation costs among those three rate classes. Nor does Ms. Thomas demonstrate that the publicly available information she relies upon is a legitimate method for allocating costs to different rate classes. As such, her approach to calculating components is irrelevant for allocating GSR costs and setting GSR rates for different customer classes. If the base generation revenues reflect AEP Ohio's overall costs, then they should be allocated to individual customer classes based on traditional cost-allocation methodologies used for Cost of Service ("COS") ratemaking. Mr. Roush, however, testifies that AEP Ohio's cost allocations are based on "very old cost relationships." If that is the case, then the solution is obvious: AEP Ohio should perform a new class cost-of-service study to determine how its costs can be properly allocated to each customer class. Because AEP Ohio has not allocated costs in this manner, but has instead based its allocation on arbitrary "market prices," the allocation of base generating costs under the Stipulation is unreasonable; it has no relationship to cost causation, which is a fundamental aspect of regulated pricing.

C. The Proposed Market Transition Rider is Unreasonable and Unfairly Subsidizes Certain Customers.

Q. PLEASE DESCRIBE THE MARKET TRANSITION RIDER ("MTR").

A. According to AEP Ohio witness Roush, "The MTR is a nonbypassable rider designed to limit the first, second, and third year changes in rates for all customer classes to uniformly accomplish 50% of the transition from current rates to market based rates."[45] The Stipulation states that "The MTR is designed to produce rate certainty and stabilized pricing during the transition to deregulation of generation service pricing."[46] Furthermore, the MTR is designed to recover $24 million of revenue to AEP Ohio during calendar year 2012, unless securitization is completed earlier. After that, the MTR is designed to be revenue neutral.

Q. HOW DO YOU INTERPRET THE MTR?

A. In my opinion, the MTR is designed to reduce the "rate shock" associated with AEP Ohio's proposal to reallocate generation costs based on its arbitrary "market pricing" relationships I discussed previously.

Q. IS THERE ANY REASONABLE BASIS FOR ESTABLISHING THE MTR AS A NONBYPASSABLE RIDER?

A. No. There is no rational economic basis either for forcing customers who take service from CRES providers to pay an additional MTR. Nor is there any rational economic basis for certain shopping customers to receive an MTR subsidy.

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[45] Roush Testimony at 11:13-15.

[46] Stipulation at 5, par. IV.1.c.

Q. WHY IS THERE NO RATIONAL ECONOMIC BASIS FOR FORCING CERTAIN SHOPPING CUSTOMERS TO PAY AN ADDITIONAL MTR OR TO RECEIVE AN MTR SUBSIDY?

A. The reason is that shopping customers are, by definition, paying "market prices." In other words, shopping customers shop because it makes economic sense to do so. Therefore, if, *arguendo*, AEP Ohio's rates proposed under the ESP truly reflect how markets price different classes of service, then those prices will allow AEP Ohio customers to make unbiased comparisons between the cost of SSO service and the cost of competitive alternatives. Instead, with the MTR, AEP Ohio will distort those very comparisons, damaging the "transition" to competition.

Q. DOES THE STIPULATION PROVIDE ANY EXPLANATION FOR WHY GS1 AND GS2 SCHOOLS WHO WERE SHOPPING AS OF SEPTEMBER 7, 2011, AND ALL GS2 CUSTOMERS WHO SHOP AFTER SEPTEMBER 6, 2011 WILL RECEIVE A SPECIAL $10/MWH SHOPPING CREDIT?

A. No. The Stipulation does not provide any reason for the special credit. However, load factors for schools are typically quite small. In other words, electric consumption peaks when school is in session during the day, but is much lower when school is not in session each day. Because of the low load factor, schools may be relatively high cost customers to serve compared to a high load factor customer, such as a factory or hospital that operates around the clock. Thus, by providing an additional $10/MWh shopping credit, AEP Ohio provides an incentive for schools to migrate to CRES providers, while AEP Ohio focuses on more profitable customers to serve. Furthermore, the GS2 rate class is called "General Service – Low Load Factor." Thus, again, AEP Ohio appears to be providing a subsidy to customers for whom it is more expensive to serve than customers having higher load factors.

Q. UNDER THE STIPULATION, WILL OTHER AEP OHIO RATEPAYERS BE FORCED TO PAY FOR THIS SPECIFIC SUBSIDY?

A. Yes. This is an example of an anticompetitive cross-subsidy. AEP Ohio offers no cost-basis for the shopping credit, nor shows that the additional credit is justified under what AEP Ohio refers to as "market-based" pricing. Indeed, if the reason were the latter, than AEP Ohio would presumably have revised the MTR to reflect that fact.

Q. DO THOSE OTHER RATEPAYERS BENEFIT BY BEING FORCED TO PAY FOR THE GS1/GS2 RATE SUBSIDY?

A. No. Forcing certain shopping customers to pay the MTR clearly forecloses competition, by making it that much more expensive to shop. Similarly, subsidizing certain classes of shopping customers, including the proposed $10/MWh "shopping credit" is anticompetitive.[47] For example, there is no economic basis for levying $23.40/MWh and $15.80/MWh MTR charges, respectively, on CSP's non-school GS1 and GS2 customers who wish to shop, while providing a $10/MWh credit to schools customers. Forcing one set of ratepayers to subsidize shopping by another set of ratepayers is completely incompatible with developing a competitive market.

D. The Nonbypassable Generation Resource Rider is Unreasonable and Will Foreclose Competition.

Q. PLEASE DESCRIBE THE GRR.

A. The Generation Resource Rider is a nonbypassable rider designed to collect AEP Ohio's investments in generating resources. Under the Stipulation, AEP Ohio agrees to only pursue approval for the Turning Point Facility and for MR6 during the term of the ESP. Moreover, AEP Ohio must demonstrate how these projects, and any other projects AEP Ohio wishes to develop under the GRR, meet the applicable requirements under R.C. 4928.143(B)(2). However, unlike

[47] Stipulation IV.1.c.

AEP Ohio's initial ESP filing in January, as supplemented with additional testimony filed July 1, 2011, AEP Ohio is not officially requesting a specific GRR value under the Stipulation. Rather, AEP Ohio wishes to establish the GRR as a matter of policy, and in a later proceeding specifically apply for recovery of the costs associated with the Turning Point facility and MR6.

Q. WHAT DOES R.C. 4928.143(B)(2)(C) REQUIRE FOR A DISTRIBUTION UTILITY TO OWN AND OPERATE A GENERATING RESOURCE WHOSE COSTS ARE RECOVERED THROUGH A NONBYPASSABLE CHARGE?

A. R.C. 4928.143(B)(2)(c) states (with emphasis added), in part:

> 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. 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. 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.

For AEP Ohio to build and operate a generating facility, and recover all of the costs of that facility, including a return on its investment, from all ratepayers, AEP Ohio must be able to show there is a need for the facility, that it will competitively bid out the facility, and that Ohio customers – including shopping customers – will benefit from that facility.

Q. WHY MUST SHOPPING CUSTOMERS BENEFIT, IN ADDITION TO SSO CUSTOMERS BENEFITING? ISN'T A GENERATING RESOURCE SOURCED UNDER R.C. 4928.143(B)(2)(C) JUST FOR THE BENEFIT OF SSO CUSTOMERS?

A. That is not how I interpret the language of the statute, which refers to Ohio consumers, not just SSO customers. Indeed, R.C. 4928.143(C)(1) makes this clear: "if the commission so approves an application that contains a surcharge under division (B)(2)(b) or (c) of this section, the commission shall ensure that the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge."

Q. IS THERE ANY REASON TO BELIEVE THAT A NONBYPASSABLE GRR BASED ON THE COSTS OF THE TURNING POINT FACILITY AND MR6 WOULD BE CONSISTENT WITH R.C. 4928.143(B)(2)(C)?

A. No. There is no evidence that the Turning Point and MR6 projects will satisfy the requirements of that section in order to obtain approval of a nonbypassable surcharge. Specifically, nothing in the Stipulation states that these two projects will be sourced using a competitive-bid process so as to obtain least-cost generation. In fact, in the case of the Turning Point facility, AEP Ohio's response to IEU-Ohio's INT-007 (attached as Exhibit JAL-5), admitted that its agreement with Turning Point was not sourced through a competitive bid process. Instead, AEP Ohio stated in its original ESP application that it had unilaterally entered into "highly confidential negotiations" with the project developers.[48] Furthermore, according to AEP Ohio witness Godfrey, who submitted testimony in support of the original ESP application, AEP Ohio also had been in bilateral negotiations with the proposed supplier of photovoltaic modules, Isofoton, S.A., based in Spain.[49] Bilateral negotiations do not meet the "competitive bidding" requirements for a nonbypassable rider, as described in R.C. 4928.143(B)(2)(b).

Q. HOW WOULD AEP OHIO DEMONSTRATE THERE IS A NEED FOR THE TURNING POINT FACILITY OR THE MR6 FACILITY?

A. In a resource planning sense, "need" for a resource is demonstrated by showing that it is a least-cost alternative to meeting the projected demand for electricity. Thus, AEP Ohio would have to demonstrate that the levelized cost of the Turning Point and/or MR6 facilities would be less than the forecast market price of energy. In other words, AEP Ohio must demonstrate that it

48 Application, p. 11.

49 Godfrey Supplemental at 16:3-4.

can "beat the market" over the long-term by building and operating generating facilities. The folly of this is precisely why Ohio moved to market-based pricing for competitive retail electric generation service beginning in 2001.

Q. HOW DOES THAT BENEFIT CUSTOMERS WHO TAKE SERVICE FROM CRES PROVIDERS?

A. Unless AEP Ohio provided a specific "credit" to shopping customers for their "share" of the benefits of the Turning Point or MR6 facilities that is greater than the GRR itself, then shopping customers will not benefit. They will continue to suffer economic harm and the GRR will continue to foreclose market competition, contrary to Ohio policy.

Q. BUT IN THE STIPULATION, SSO CUSTOMER LOAD WILL BE AUCTIONED OFF BEGINNING IN JUNE 2015. HOW WILL SPECIFIC GENERATING RESOURCES ACQUIRED UNDER THE GRR BENEFIT SSO CUSTOMERS?

A. That is unknown at this time. Section IV.1.r of the Stipulation merely states that "The manner in which to include any dedicated resources under Paragraph IV.1.d above in any auction-based SSO procurement process shall be developed in the stakeholder process identified above and addressed in any CBP." Thus, the Stipulation takes a "trust us" position.

Section IV.1.r of the Stipulation does state that, as part of the proposed competitive procurement process for SSO load that would begin June 1, 2015, resources acquired under the GRR "shall be bid into the PJM energy and capacity markets."[50] However, this points to a significant flaw in the GRR. Specifically, if the prevailing market prices for capacity and energy turn out to be lower than the embedded costs of a GRR resource that had previously been found to be prudent, then all customers – SSO and shopping – would presumably be liable for the above-market costs. This is precisely the type of financial risk placed on ratepayers that competitive electric markets have been developed to avoid. And, as I stated previously, there is

[50] Stipulation IV.1.r.

no guarantee that ratepayers taking service from CRES providers will be credited more than the GRR itself. Thus, again, shopping customers, and market competition, will be harmed.

Q. UNDER THE STIPULATION, WOULD AEP OHIO BE FORCED TO ABSORB ALL ABOVE-MARKET COSTS OF GRR RESOURCES THAT, HAVING BEEN FOUND TO BE PRUDENT, TURN OUT TO BE MORE COSTLY THAN THE MARKET?

A. No. There is no language in the Stipulation that would provide ratepayers with this protection from being forced to absorb above-market costs.

Q. THE STIPULATION ALSO STATES THAT AEP OHIO WILL PURSUE DEVELOPMENT OF UP TO 350 MW OF COMBINED HEAT AND POWER ("CHP"), WASTE ENERGY RECOVERY ("WER") AND DISTRIBUTED GENERATION RESOURCES.[51] WILL THE COST OF THOSE RESOURCES BE RECOVERED UNDER THE GRR?

A. That is unknown. The Stipulation merely states that the costs would be "recovered under an appropriate rider." AEP Ohio witness Hamrock has suggested that the "appropriate rider. . . might be a GRR type rider if it's an asset owned by the company" or might be through the Alternative Energy Rider.[52] In my opinion, under no circumstances should recovery occur through any nonbypassable rider, as that would further foreclose competition, contrary to state policy. Because these resources would be developed to support AEP Ohio's renewable energy benchmarks,[53] the costs should be recovered through a bypassable rider as required by R.C. 4928.64(E).

In addition, the Stipulation lacks any information regarding how these resources would be developed and the level of above-market costs SSO customers might be required to pay. AEP Ohio should include that cost in its ESP vs. MRO comparison.

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[51] Stipulation IV.2.c.

[52] Deposition of Joseph Hamrock, 9/21/2011, at p. 57.

[53] *Id.* at p. 58.

E. The DIR Is an Additional Cost of the ESP.

Q. PLEASE DESCRIBE THE DIR.

A. The Distribution Investment Rider is a nonbypassable rider intended to allow AEP Ohio to recover its property taxes, commercial activity tax, associated income taxes, and to earn a return on and of post-2000 plant-in-service.[54]

Q. HOW WILL APPROVAL OF THE DIR BE TAKEN INTO ACCOUNT IN AEP OHIO'S DISTRIBUTION RATE CASE?

A. This is unclear. AEP Ohio currently has pending an application for a distribution base rate increase in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR with a date certain of August 31, 2010. The Commission Staff filed separate reports for CSP and OPC in these dockets on September 15, 2011. Taken together, the average of the Staff Report's "Low" and "High" recommendations is an annual increase of $21.6 million, as shown in Table 12.

Table 12: AEP Ohio Requested Distribution Amounts and Staff Recommendations

Company	AEP Requested	Staff Recommended		
		Low	High	Average
CSP [1]	$34,211,000	($9,541,000)	($2,302,000)	($5,921,500)
OP [2]	$59,604,000	$23,220,000	$31,909,000	$27,564,500
TOTAL	$93,815,000	$13,679,000	$29,607,000	$21,643,000
Notes:				
[1] Source: Staff Report, Case No. 11-351-EL-AIR, Schedule A-1				
[2] Source: Staff Report, Case No. 11-352-EL-AIR, Schedule A-1				

The distribution amounts provided for recovery of all distribution plant-in-service as of the date certain. However, if the DIR is approved in the form set forth in the Stipulation, but the plant-in-service included in the DIR is also included in rate base supporting Staff's recommended annual increase of $21.6 million, then AEP Ohio will be double-recovering post-2000 costs through the date certain of August 31, 2011. In other words, the DIR reaches back an additional 10 years,

[54] Stipulation at 8, IV.1.n.

allowing AEP Ohio to double recover plant-in-service costs during those 10 years twice. Clearly, such double-recovery is incompatible with basic rate regulation.

Q. HOW DID YOU CALCULATE THE VALUE OF THE DIR OVER THE TERM OF THE ESP?

A. I assumed the increase in the cap for recovery of DIR from 2012 to subsequent years under the term of the ESP would capture the revenue requirement effect of increased net distribution investment after 2012 and that AEP Ohio would be able to recover those increased revenue requirements through filings of additional base rate increase cases. The amount of revenue increase permitted under the DIR is $18 million between 2012 and 2013, and $20 million annually between 2013 and the period 2014 through May 2015.[55] Under this assumption, the $64.4 million difference between the ESP and the MRO for 2012 would continue for the remainder of the ESP term. The $64.4 million of additional revenue recovery for 2012 equates to $219.9 million over the period January 1, 2012 through May 2015.

Q. DOES THE DIR IMPACT THE COMPARISON OF THE PROPOSED ESP AND THE EXPECTED RESULTS OF AN MRO?

A. Yes. The Commission should take into consideration the additional cost of the DIR because it is a part of the proposed ESP that would not necessarily be included in an MRO. If one takes into consideration the impact of the DIR, the proposed ESP will cost an additional $219.9 million more than an MRO over the term of the proposed ESP, as shown in Table 13.

[55] Stipulation at 9, IV.1.n.

Table 13: DIR Additional Cost Above MRO

Filing	2012	2013	2014	Jan - May 2015	41 Month Total
ESP Stipulation [3]					
Base	$86,000,000	$86,000,000	$86,000,000	$35,833,333	$293,833,333
Increase	$0	$18,000,000	$38,000,000	$15,833,333	$71,833,333
Total	$86,000,000	$104,000,000	$124,000,000	$51,666,667	$365,666,667
MRO Assumption [4]					
Base	**$21,643,000**	$21,643,000	$21,643,000	$9,017,917	$73,946,917
Increase	$0	$18,000,000	$38,000,000	$15,833,333	$71,833,333
Total	$21,643,000	$39,643,000	$59,643,000	$24,851,250	$145,780,250
ESP vs. MRO					
Net Increase	$64,357,000	$64,357,000	$64,357,000	$26,815,417	$219,886,417

Notes:

[3] Source: Rider DIR revenue caps from Stipulation in Case No. 11-346-EL-SSO

[4] Assumes 2012 increase based on midpoint of Staff Report recommended revenue increase from pending base distribution cases, 11-351-EL-AIR, 11-352-EL-AIR. January 2013 - May 2015 estimated revenues assume that AEP would file for, and receive, base distribution increases equal to the annual increases in Rider DIR caps.

Q. HOW DID YOU CALCULATE THE INCREASED COST OF THE DIR INCLUDED IN THE PROPOSED ESP?

A. I based the increase on the difference between what the proposed ESP provides for the DIR versus what amount the Commission Staff recommended in their Staff Reports. I assumed that the increase in these distribution rates would be effective January 1, 2012 and compared those costs against the annual cap amount AEP Ohio could recover under the Revised ESP's DIR of $86 million beginning January 1, 2012. That increases by $18 million to $104 million in 2013 and by $20 million over the 2013 amount to $124 million in 2014. I then prorated the $124 million annual value for the first 5 months of 2015, as shown in Table 13. Similarly, I assumed that the $21.6 million average increase under Staff's proposal would also increase in 2013 and 2014 by those same $18 million and $20 million values. Therefore, under the ESP, AEP Ohio would collect $64.4 million more in revenue in each year 2012-2014, and an additional $26.8

million during the first 5 months of 2015 than it would collect under an MRO if the Commission approved Staff's recommended mid-range increase.

Q. IS THIS A CONSERVATIVE ESTIMATE?

A. Yes. My analysis assumes that under an MRO, AEP Ohio would file annual base distribution rate increases that produce revenue increases equal to the amount of the annual increases for 2013 and 2014 through May 2015 under the DIR. However, based on the timing mechanism associated with establishment of the date certain in a distribution rate increase case, it would be highly unlikely for AEP Ohio to capture revenue increases of the same amount of $18 million in 2013 and an additional amount of $20 million revenue increase on January 1, 2014, as are contained in the ESP's DIR.

Q. SHOULD AEP OHIO TAKE THE DIR INTO CONSIDERATION IN DETERMINING WHETHER THE ESP IS BETTER THAN AN MRO?

A. Yes. By not doing so, AEP Ohio has understated the cost of the ESP compared to an MRO.

Q. DOES THE ADDITIONAL DIR COST AFFECT THE PRESENT VALUE "BENEFIT" CALCULATION PERFORMED BY MR. ALLEN?

A. Yes. Table 14 reproduces Table 2, except I have added the additional costs of the DIR and calculated the impact on the quantifiable ESP benefits. As line [6] of this table shows, including the excess DIR costs increases the present value cost by an additional $193 million. As a result, the overall present value cost of the proposed ESP to ratepayers increases from just over $1 billion to almost $1.2 billion.[56] Similarly, when combined with Mr. Schnitzer's estimates of

[56] Table 2 does not take into account Mr. Schnitzer's corrections to the "ESP Price Benefit" in row [1], which, if included, would further increase the present value cost of the ESP.

the costs of the ESP as compared to an MRO (on a non-NPV basis), the ESP fails under every scenario.[57]

Table 14: Recalculation of Exhibit WAA-4 with DIR Cost (Million$)

Line	Item	NPV @ 6%	Year 2012	2013	2014	2015	2016	2017	2018
[1]	ESP Price Benefit for Non-Shopping Customers	$130	$21	$41	$51	$38			
[2]	Value of Discounted Capacity Provided to CRES Providers	($1,270)	($497)	($528)	($312)	($87)			
[3]	Reduced PIRR Carrying Costs	$104	$35	$32	$28	$24	$18	$12	$4
[4]	Partnership With Ohio Initiative	$10	$3	$3	$3	$3	$1		
[5]	Ohio Growth Fund Initiative	$17	$5	$5	$5	$5	$2		
[6]	Excess Cost of DIR	($193)	($64)	($64)	($64)	($27)			
[7]	Total Quantifiable ESP Benefits	($1,174)	($497)	($512)	($289)	($44)	$22	$12	$4

IV. THE STIPULATION WILL DAMAGE THE OHIO ECONOMY.

Q. WILL THE STIPULATION BENEFIT THE OHIO ECONOMY?

A. No. Charging of capacity costs to CRES providers that are far greater than the PJM RPM market-clearing prices, coupled with nonbypassable GRR and MTR riders, will impose needless costs and foreclose market competition.

Q. CAN THE TURNING POINT PROJECT GO FORWARD EVEN WITHOUT GUARANTEED COST RECOVERY THROUGH A NONBYPASSABLE SURCHARGE?

A. Yes. The Participation Agreement ("PA") between Turning Point Solar, LLC and AEP Ohio,[58] shows that AEP Ohio can waive any of the requirements under Article 6.1 of the PA.

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[57] *See* Testimony of Michael M. Schnitzer filed Sept. 27, 2011, Exhibit MMS-4.

[58] Exhibit JFG-6 to Supplemental Direct Testimony of Jay F. Godfrey on Behalf of Columbus Southern Power Company and Ohio Power Company, filed July 1, 2011.

Q. ARE THERE PUBLISHED STUDIES OF THE ECONOMIC COSTS OF SUBSIDIZING RENEWABLE GENERATION?

A. Yes. There are a number of published studies. One of the most recent is the Ohio EPS Study that is attached as Exhibit JAL-6. The study estimated that, by the year 2025, the state's alternative energy portfolio standard would cause ratepayers in the state to pay $1.4 billion extra for electricity in that year and cause the loss of almost 9,800 jobs, roughly 700 jobs for every $100 million increase in electricity costs.

Several studies have examined the cost of renewable mandates in European countries. For example, a study published in Spain estimated that each green job created in Spain's wind and solar industries led to the loss of over two jobs in the rest of the Spanish economy and a required spend of over one million Euros ($1.4 million) for each wind industry job created.[59] A study conducted by researchers in Germany reached similar conclusions, finding that for each worker in Germany's solar PV industry, the subsidy averaged 175,000 Euros ($250,000).[60] In the case of Solyndra, the $535 million supported 1,100 jobs, for a cost of almost $500,000 per job.

Q. ARE YOU AWARE OF OTHER STATE UTILITY COMMISSIONS THAT HAVE CONCLUDED THAT UNECONOMIC GENERATION INVESTMENTS DESTROY JOBS?

A. Yes. In an April 2010 Order that rejected a proposed contract between Deepwater Wind and National Grid, the Rhode Island PUC stated:

> It is basic economics to know that the more money a business spends on energy, whether it is renewable or fossil based, the less Rhode Island businesses can

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[59] G. Calzada et al., "Study of the Effects on Unemployment of Public Aid to Renewable Energy Sources," Universidad Rey Juan Carlos, March 2009, published at: PROCESOS DE MERCADO. Volumen VII, Número 1, Primavera 2010. Available at: Hhttp://www.juandemariana.org/pdf/090327-employment-public-aid-renewable.pdfH .

[60] M. Frondel, N. Ritter and C. Vance, "Economic Impacts from the Promotion of Renewable Energies: The German Experience, Final Report," Rheinisch-Westfälisches Institut für Wirtschaft sforschung, October 2009. Available at: Hhttp://www.instituteforenergyresearch.org/germany/Germany_Study_-_FINAL.pdfH.

> spend or invest, and the more likely existing jobs will be lost to pay for these higher costs.[61]

Yet, AEP Ohio is advocating precisely that its business and residential customers be forced to pay higher prices for uneconomic generation so as to create jobs. The Rhode Island PUC realized this was economic nonsense. Because Ohio has far more manufacturing industry and is more electric-intensive than Rhode Island, lower cost electricity produced by economically-sourced generation is even more important for the future economic well-being of Ohio.

Q. WILL AEP OHIO'S PROPOSED ESP RAISE ELECTRICITY COSTS?

A. Yes. As Mr. Schnitzer testifies, AEP Ohio determines that its proposed ESP cost is below an MRO because the company underestimates and omits several cost categories, while overestimating the costs of procuring energy supplies, leading to an ESP that is more costly than would be achieved using market mechanisms. In addition, AEP Ohio's above-market $255/MW-day capacity charge will prevent some customers from accessing market pricing while over-charging others, which is equivalent to supporting uneconomic investments.

Q. WHY WILL HIGHER GENERATION PRICES RESULTING FROM AEP OHIO'S UNECONOMIC INVESTMENTS CAUSE JOB LOSSES?

A. The effects of AEP Ohio's shopping restrictions and nonbypassable riders will have widespread impacts on the Ohio economy, extending far beyond simply raising customers' monthly electric bills. For example, households forced to spend more money on subsidized generation will reduce their spending on other goods and services, affecting businesses that cater to those consumers. Similarly, businesses paying increased electric bills must either reduce their output, increase their prices, or both. These impacts will, in turn, lead to job loss, which will in turn further reduce consumer spending, causing even greater economic losses.

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[61] *In Re: Review of New Shoreham Project Pursuant to R.I. Gen Laws § 39-26.1-7*, Docket No. 4111, Report and Order, April 2, 2010, at 82 (emph. added). The Rhode Island PUC's decision was effectively overridden by subsequent legislation, but the point still stands.

Because of the interconnections among industries, and between industries and households, a change in the price of just one good or service can cause ripple effects throughout the Ohio economy. Positive ripple effects add jobs and increase disposable income as more workers are hired, more equipment and supplies are purchased from other local businesses, more wages are paid to employees, and more taxes are paid to government entities. Conversely, negative ripple effects result in job loss and decreased disposable income. These impacts are called multiplier effects or multipliers. In other words, the impacts of uneconomic generation investments would "ripple" through the entire Ohio economy, leading to job losses and reductions in economic output.

Q. HOW CAN THE IMPACTS OF UNECONOMIC GENERATION INVESTMENTS ON THE OHIO ECONOMY AND ON JOBS BE EVALUATED?

A. There are two general methods that are used to analyze economic impacts. The first method uses what is called a "computable general equilibrium" ("CGE") modeling framework. This is the type of model used in the Ohio EPS Study previously attached as Exhibit JAL-6. The second method, which I have used to analyze the impact of the Stipulation, is called an "input-output" ("I/O") modeling framework.

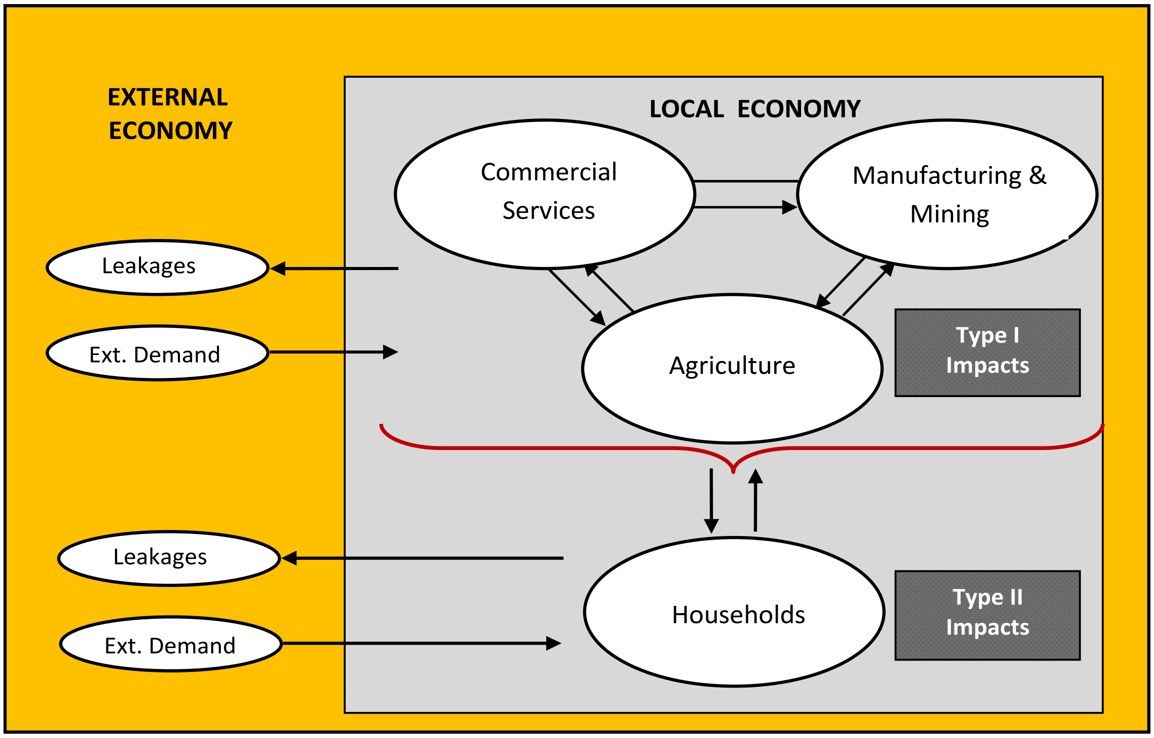
Q. PLEASE EXPLAIN HOW AN I/O MODEL WORKS.

A. Input-output analysis traces the interdependencies of an economy, specifically the sales and purchases of goods among all of the sectors of an economy.[62] For example, constructing a new high-voltage transmission line will require the purchase of concrete that will be used as foundations for transmission towers. But to manufacture that concrete, firms must purchase inputs including sand, gravel, and electricity. Similarly, transmission towers will be made of steel that is manufactured in steel mills that use iron ore, which is mined by other firms. Moreover,

[62] Nobel Prize winning economist Wassily Leontief is generally considered to be the "father" of Input-Output analysis. For an introduction to I/O modeling, see his treatise *Input–Output Economics*, 2nd Ed. (New York: Oxford University Press 1986).

construction requires the use of many workers who then spend their wages on all varieties of goods and services. An input-output framework is designed to trace all of those relationships. Figure 2 shows the general analytical framework for an I/O model.

Figure 1: I/O Model Structure



In an I/O model, a "local" economy, which can be a county, state, multi-county or multi-state region, etc., is broken down into manufacturing & mining, commercial services, and agriculture. There is also a household sector and, in some cases, a separate government sector. Purchases outside the local economy are considered "leakages." On the other hand, sales by business and industry of goods and services to outside the local economy are treated as external demand. External demand increases the level of economic activity within the local economy.

There are also household impacts. Households in the local economy purchase goods and services from local industries, as well as from the broader external economy. Moreover, external households purchase goods and services from firms within the local economy. If household impacts on the economies (e.g., the wages households earn that are spent on goods and services), are excluded from the economy, the resulting economic impacts are called "Type I impacts." If households are included, the resulting economic impacts are called "Type II impacts." For each sector of the economy modeled, the I/O model also traces employment and wages. Thus, concrete manufacturing within the local economy may require an average of, say, 10 employees for every million dollars of concrete produced, while grocery stores may employ 30 people for every million dollars of retail sales. Type II impacts include changes in household spending that result from policy changes, such as changes in income tax rates, as well as how changes in industrial output affect wages paid and expenditures households make on goods and services.

Q. PLEASE EXPLAIN HOW YOU ESTIMATE IMPACT OF AEP OHIO'S UNECONOMIC INVESTMENTS.

A. To perform this analysis, I have used one of the most well-known economic impact models, the **IM**pact for **PLAN**ning ("IMPLAN") model.[63] IMPLAN is the most well-known and widely used I/O model and is used by numerous government agencies at both the federal and state levels, including the Ohio Department of Development.

Q. PLEASE EXPLAIN HOW IMPLAN WORKS.

A. The IMPLAN model begins with the most current national transactions matrix developed by the current National Bureau of Economic Analysis Benchmark Input-Output Model. The model breaks down the U.S. economy into over 500 separate economic sectors in agriculture, manufacturing, commercial services, and government. Next, the model creates state and county-level values by adjusting the national level data, such as removing industries that are not present in a particular state or economy.

[63] IMPLAN was first developed in the late 1970s by the U.S. Forest service to analyze the economic impacts of different forestry policies. The current version of IMPLAN is maintained by MIG Inc., formerly known as the Minnesota IMPLAN group. MIG was founded in 1993 by Scott Lindall and Doug Olson as an outgrowth of their work at the University of Minnesota, which began in 1984. This developmental work closely involved the U.S. Forest Service's Land Management Planning Unit in Fort Collins, and Dr. Wilbur Maki at the University of Minnesota.

The model also estimates imports and exports using what are called regional purchase coefficients ("RPCs"). A RPC measures the proportion of the total supply of a commodity or service required to meet a particular industry's intermediate demands and final demands that are produced locally. The larger the RPC value, the greater the percentage of total regional demand that is met through local supplies, and the fewer expenditures that "leak out" of the local economy. The larger the local economy, e.g., an entire state rather than an individual county within a state, the larger will be the RPC values. RPCs are important for estimating the economic impacts of higher electricity prices, because the larger the leakages out of the Ohio economy, the less the overall impacts will be in the state.

One of the key features of IMPLAN (and all I/O models) is the calculation of "multipliers." Multipliers capture how the impacts of a policy change ripple through the local economy. For example, suppose electric prices in the state increase by $100 million because of a lack of retail electric competition and AEP Ohio's imposition of numerous nonbypassable riders. In that case, collectively, businesses and individuals will spend $100 million more on electricity and have $100 million less to spend on all other goods and services.

A business that is compelled to pay for AEP Ohio's uneconomic investment through a nonbypassable rider would likely reduce its output, increase the price of the goods and services it sells, or both. An electric-intensive business might even decide to relocate out-of-state; for example, aluminum smelting companies left the Pacific Northwest after their electric rates were increased and relocated to other countries offering lower price electricity. If the business reduced its production, it would purchase fewer supplies from other businesses, which, in turn, would respond to decreased demand for the goods and services they produce by purchasing fewer supplies from other businesses, and so forth. And, of course, all of those other businesses would also pay more for electricity. In other words, the impacts of uneconomic generation investments would ripple through the Ohio economy.

If the impacts on households were also considered, the multiplier would increase. Not only would businesses reduce their output because of the costs of uneconomic generation investments, but households would have less disposable income. Moreover, job losses at businesses affected by the costs of uneconomic generation investments would reduce wage payments, thereby reducing overall household income. Reduced wages would also mean that state and local governments would collect fewer tax revenues, causing them to reduce expenditures. The resulting Type II impacts on the Ohio economy, therefore, would be even greater.[64]

Q. PLEASE EXPLAIN HOW YOU ESTIMATED THE IMPACTS ON EMPLOYMENT IN OHIO RESULTING FROM AEP OHIO'S UNECONOMIC INVESTMENTS.

A. To model the economic impacts of uneconomic generation investments on the Ohio economy, I assumed that businesses and consumers would reduce their purchases of other goods and services by an equivalent amount, i.e., an individual household forced to spend \$100 more on electricity would consequently spend \$100 less on all other goods and services. I also assumed that households would continue to purchase the same proportions of those other goods and services. For example, if an individual had previously spent \$200 annually on haircuts and three times as much, or \$600, annually on clothes, I assumed he would continue to spend three times more for clothes as haircuts, but at lower levels, *e.g.*, \$190 on haircuts and \$570 (3 x \$190) on clothes. Similarly, businesses paying more for electricity would reduce purchases of all of the

[64] In addition to calculating standard Type I and Type II multipliers, IMPLAN can also calculate what are called "SAM multipliers." SAM stands for "Social Accounts Matrix," and is a more detailed breakdown of transactions within an economy. Specifically, whereas the typical input-output framework captures production and consumption, it leaves out some income transactions, such as taxes, savings, and transfer payments. IMPLAN allows users to capture these components as well, and thus derive what are called SAM multipliers. SAM multipliers are a form of Type II multiplier. Thus, SAM multipliers incorporate direct, indirect, and induced impacts, while accounting for the effects of savings, taxes, and transfer payments. Exhibit JAL-7 provides a mathematical description of an I/O model, including how multipliers are estimated.

other inputs they used to produce their goods and services by the same percentages, thus maintaining the same relative proportions of each.[65]

Next, I derived an overall employment multiplier for the Ohio economy, equal to the weighted average of the individual sector employment multipliers, excluding the electricity sector.[66] I then estimated an overall weighted average RPC value. That is, I determined the fraction of total expenditures that, on average, businesses and individuals spend at Ohio firms.[67] Next, I estimated the weighted average number of jobs per millions of dollars of output for all industries in the state. Then, I estimated a weighted average value for jobs per million$ of output in the Ohio economy. Finally, using the overall RPC value, the weighted average job multiplier, and the weighted average jobs per million$ of output, I was able to calculate the total job impacts of per million$ of increased generation costs in the state.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS?

A. For my analysis, I have focused on the above-market costs of capacity, which as shown in Table 1 will impose an additional cost of $1.27 billion on ratepayers over the 41-month period of the ESP through May 2015 for which the non-market-based capacity charge is planned prior to AEP Ohio joining RPM for the remaining period covered by the ESP.[68] The results are summarized in Table 15.

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[65] The Leontief input-output framework assumes what are called “fixed production coefficients.” This means that firms cannot substitute inputs, e.g., using more natural gas instead and less electricity, to produce the same output. The production coefficients are called “technical coefficients” in the I/O modeling framework. Although this assumption does not hold in the long-run, it is reasonable for short-run impact studies. See Exhibit JAL-7 for a discussion of how this analysis was performed.

[66] In IMPLAN, Sector 31 is “Electric power generation, transmission, and distribution.”

[67] It is also important to remember that a percentage of the wages individual employees are paid is transferred as payroll taxes. The assumed overall payroll tax rate is 15%, which includes both Social Security and Medicare.

[68] To be conservative, I did not include the additional costs imposed by the excess DIR costs.

Table 15: Annual Lost Jobs Caused by Above-Market Capacity Costs

Line No.	Item	Value
[1]	Above-Market Present Value Capacity Cost (Millions of 2012 $)	$1,269.8
[2]	2012 - 2009 Deflator	1.037
[3]	Above-Market Present Value Capacity Cost (Millions of 2009 $)	$1,224.7
[4]	Average Annual 2009$ Cost (41 mos ESP)	$358.46
[5]	Ohio Regional Purchase Coefficient	62.57%
[6]	Ohio Jobs Multiplier	2.882
[7]	Ohio Jobs / Million 2009$ Output	7.171
[8]	Annual Lost Jobs	4,635

Notes:

[1] Source: Table 1, line [10].
[2] Source: 2009-2010, U.S. Federal Reserve; 2010-2012: U.S. EIA, Annual Energy Review, 2010-2035.
[3] Equals [1] / [2].
[4] Equals [3] x 12 / 41.
[5] Source: IMPLAN, Ohio database and methodology shown in Exhibit JAL-XX
[6] Source: IMPLAN, Ohio database and methodology shown in Exhibit JAL-XX
[7] Source: IMPLAN, Ohio database and methodology shown in Exhibit JAL-XX
[8] Equals [4] x [5] x [6] x [7].

As Table 15 shows, the above-market capacity costs AEP Ohio intends to charge will, on average, result in the loss of over 4,500 jobs each year during the first 41 months of the proposed ESP. Thus, rather than promoting economic growth and job creation in Ohio, the Stipulation will destroy jobs. Moreover, the nonbypassable GRR, in addition to foreclosing retail electric competition, would create more financial uncertainty for customers and lead to higher electric prices, especially if AEP Ohio insists on including the high-cost Turning Point project in the GRR.

Q. CAN THESE ADVERSE ECONOMIC IMPACTS BE AVOIDED?

A. Yes. The best, and simplest, way to avoid these adverse economic impacts is either reject the Stipulation in its entirety or modify the ESP such that a fully competitive market starts in AEP Ohio's service territory on January 1, 2012. Competitive electric markets will provide far more long-term economic and job growth than artificial subsidies. If the Stipulation is not rejected in its entirety, then I recommend modifying it.

Q. WHAT MODIFICATIONS THE STIPULATION DO YOU RECOMMEND?

A. First, the Stipulation should be modified so that all CRES providers are charged the PJM RPM market-clearing price for capacity for the entirety of the ESP. That price is economically efficient and fair. Second, rather than using competitive auctions to provide SSO service beginning June 1, 2015, those auctions should begin on January 1, 2012, when the new ESP is scheduled to begin. Third, the nonbypassable GRR should be eliminated. Competitive wholesale electric markets are working well and there is surplus capacity. There is simply no reason to believe that AEP Ohio must build new generating resources, nor does it make economic sense to force all ratepayers, including those who take service from CRES providers, to bear the financial risks of generating resource development. Transferring those risks from ratepayers to generation suppliers, as occurs in competitive wholesale markets, was one of the key policy goals of developing those competitive markets in the first place. Approving the GRR as a place-holder, as requested by AEP Ohio, would not itself transfer those risks to ratepayers but would cast a cloud of uncertainty over competitive markets. Fourth, the nonbypassable MTR should be eliminated. Not only is there no economic reason to charge or subsidize shopping customers, who by definition have chosen to purchase market-priced electricity, but a nonbypassable MTR simply penalizes or rewards different groups of customers without justification. There is no economic basis for providing a $10/MWh shopping credit to GS1 and GS2 schools and certain GS2 customers, and no economic reason why other ratepayers should pay for that shopping credit. Fifth, the nonbypassable DIR should be eliminated or corrected to remove the double recovery of distribution plant investment costs. Finally, by implementing competitive auctions for SSO service immediately, there would be no need for the MTR.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

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

FirstEnergy Solutions Corp.

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

  Subject: AEO Ohio energy security plan.

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 and Vaquería Tres Monjitas, Inc.

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

PROFESSIONAL ASSOCIATIONS

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

PUBLICATIONS

Peer-reviewed journal articles

- Lesser, J., "Gresham's Law of Green Energy," *Regulation*, Winter 2010-2011, pp. 12-18.
- Lesser, J., and E. Nicholson, "Abandon all Hope? FERC's Evolving Standards for Identifying Comparable Firms and Estimating the Rate of Return," *Energy Law Journal* 30 (April 2009): 105-132.
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- Lesser, J., and L.R. Giacchino. *Fundamentals of Energy Regulation*, Vienna, VA: Public Utilities Reports, 2007.
- Lesser, J., and R. Zerbe. "A Practitioner's Guide to Benefit-Cost Analysis." In *Handbook of Public Finance*, edited by F. Thompson, 221–68. New York: Rowan and Allenheld, 1998.
- Lesser, J., D. Dodds, and R. Zerbe. *Environmental Economics and Policy*, Reading: MA: Addison Wesley Longman, 1997.

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- Lesser, J, "Short Circuit: Will Electric Cars Provide Energy and Environmental Salvation?" *Natural Gas & Electricity* (November 2009): 27-28.
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- Lesser, J., "Most Value—The Right Measure for the Wrong Market?" *The Electricity Journal* 2 (December 1989): 47–51.

Selected speaking engagements

- "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.

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-136. How are off-system sales (profits) treated in the current ESP filing for AEP Ohio?

RESPONSE

OSS profits are adjusted out of the Company's pro forma financial statements as shown on PJN Exhibit-3, page 7.

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-139. What was the actual total margin (profit) from all off-system sales each year, for the years 2000 through present for CSP and for OPCo?

RESPONSE

OPCo & CSP 's OSS margins ($000)

	OPCo	CSP
2010	81,304	73,533
2009	61,879	51,268
2008	181,498	146,560
2007	171,392	142,730
2006	199,737	133,501
2005	145,062	89,921
2004	96,988	64,849
2003	73,629	53,373
2002	77,282	57,333
2001	106,151	75,036
2000	136,352	89,001

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-140. What is the most recent estimate of the total margin (profits) from all off-system sales each year, for each year of the ESP term proposed for CSP and for OPCo?

RESPONSE

OSS Pre Tax Margins

Period	CSP ($000)	OPC ($000)	Total ($000)
2012	130,254	83,791	214,045
2013	147,378	107,615	254,993
Jan - May 2014	70,767	55,992	126,759

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-143. What percentage of OPCo's annual generation for the years 2000 through 2010, by year, was assigned to off-system sales?

RESPONSE

See OCC INT-143 Attachment 1.

Prepared By: Philip J. Nelson

OCC 4-143 Attachment 1

OPCO and CSP Annual Percentage of Generation Assigned to Off-System Sales

	OPCO	CSP
2000	15.40%	17.50%
2001	18.60%	19.90%
2002	19.90%	18.10%
2003	23.60%	24.90%
2004	19.90%	26.20%
2005	18.50%	23.40%
2006	20.20%	20.80%
2007	13.90%	27.30%
2008	11.40%	19.20%
2009	7.50%	15.30%
2010	8.90%	15.30%

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY

INT-146. In addition to megawatt-hours sales, what other off-system sales net revenues (i.e., capacity, ancillary services, etc.) were generated by CSP for the years 2000 through 2010? Were any of these net revenues used to lower rates charged to Ohio jurisdictional customers? If so, how was this done and what amounts were used to lower rates?

RESPONSE

CSP received its MLR share of OSS margins related to capacity sales made by the AEP East Pool into PJM's RPM market. Those OSS margins are included in the Company's response to OCC INT-139.

See Company's response to OCC INT-141 and OCC INT-142.

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-147. In addition to megawatt-hours sales, what other off-system sales net revenues (i.e., capacity, ancillary services, etc.) were generated by OPCo for the years 2000 through 2010? Were any of these net revenues used to lower rates charged to Ohio jurisdictional customers? If so, how was this done and what amounts were used to lower rates?

RESPONSE

OPCo received its MLR share of OSS margins related to capacity sales made by the AEP East Pool into PJM's RPM market. Those OSS margins are included in the Company's response to OCC INT-139.

See Company's response to OCC INT-141 and OCC INT-142.

Prepared By: Philip J. Nelson

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY

INT-4-005. In Exhibit LJT-2, does the "2011 Base ESP 'g' rate" include both energy and capacity costs?

RESPONSE:

The Company objects to this request as seeking information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections or any general objection the Company may have, the Company states as follows.

SB221 does not require rates for generation service, including capacity and energy, to be based on cost. AEP Ohio has not conducted a cost of service study for unbundled generation service. However, the 2011 Base ESP 'g' rate includes both energy and capacity.

Prepared By: Laura J. Thomas

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-007. Prior to entering into the Memorandum of Understanding ("MOU") with Turning Point Solar did AEP seek any competitive bids for this project?

RESPONSE

The selection of the project Developer was not competitively bid.

Exhibit JAL-6

American Tradition Institute

The Cost and Economic Impact of Ohio's Alternative Energy Portfolio Standard

AMERICAN TRADITION INSTITUTE
Washington, D.C. ◆ Raleigh ◆ Denver ◆ Bozeman

2020 PENNSYLVANIA AVENUE NW #186
WASHINGTON D.C. 20006

APRIL 2011

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Executive Summary

Ohio enacted its Alternative Energy Portfolio Standard (AEPS) legislation in May 2008. The law requires one-quarter of all electricity sales by Ohio utilities to come from "alternative energy" sources by the year 2025, with 12.5 percent required to come from sources identified as "renewable." While the law includes a provision cap electricity costs due to the mandate, it is unlikely that the cap would be breached due to its structure.

The American Tradition Institute commissioned the Beacon Hill Institute to apply its STAMP® (State Tax Analysis Modeling Program) to estimate the economic effects of the AEPS mandate. To account for excessively optimistic Energy Information Administration (EIA) measures of renewable electricity costs and capacity factors, we reviewed academic literature to provide three estimates of the cost of Ohio's AEPS mandates — low, average and high — using different cost and capacity factor estimates for electricity-generating technologies. Major cost findings include:

- The state's electricity consumers will pay $1.427 billion more for power in 2025, within a range of $262 million and $2.373 billion, because of the AEPS.
- Over the period of 2016 to 2025, Ohioans will pay an additional $8.629 billion over a baseline of no AEPS, within a range of $5.22 billion and $10.929 billion.
- Ohio's electricity prices in 2025 will increase by an average of 9.3 percent, within a range of 1.7 percent and 15.4 percent.

These increased energy prices will hurt Ohio's households and businesses and thus impair the state economy. According to the study, by 2025:

- Ohio will lose an average of 9,753 jobs, within a low-end estimate of 2,480 jobs and a high-end estimate of 15,523 jobs.
- The AEPS will reduce annual wages by an average of $334 per worker, within a range of $61 per worker and $556 per worker.
- Real disposable income will fall by $1.097 billion, within a range of $201 million and $1.824 billion.
- Net investment will fall by $79 million, within a range of $15 million and $132 million.
- The policy will cost families on average $123 per year, commercial businesses on average $867 per year, and industrial businesses on average $31,024 per year.
- From 2016 to 2025 the average household ratepayer will pay $756 in higher electricity costs; the average commercial ratepayer will pay an extra $5,350; and the average industrial ratepayer an extra $191,490.

Introduction

Beginning in May 2008, with the passage of Senate Bill 221, Ohio lawmakers began to dictate the generation technologies that utilities must use to produce the electricity sold in the state. The state passed an Alternative Energy Portfolio Standard (AEPS) that included a Renewable Portfolio Standard (RPS) and an Advanced Energy Sources (AES) requirement.

The RPS requires an increasing share of all retail electricity sold in Ohio to come from renewable sources, including solar, wind, biomass, geothermal, solid waste and hydroelectric facilities. Specifically, the law requires that beginning in 2009 at least 0.25 percent of all retail electricity sales derive from a renewable source. The share increases each year until it reaches 12.5 percent in 2025.[1] The RPS includes a provision requiring 0.5 percent of Ohio's total electricity supply derive from solar energy.[2] Moreover, half of all renewable energy production under the mandate, including solar, must be located in the state of Ohio.

The AES calls for an equal share of energy to be produced by 'Advanced Energy Sources', as has to be produced by the RPS, or 12.5 percent by 2025. AES are defined as nuclear, clean coal, fuel cells, any modification to current electric generating facilities that increases output but not emissions and demand side management practices. The AES does not contain any intermediate benchmarks prior to 2025.

The law includes cost containment provisions. Should a utility determine that their cost to comply with the AEPS would raise the price of electricity to all consumers by more than 3 percent, the utility can petition the Ohio Public Utility Commission (PUC) for a waiver. The AEPS also contains a force majeure provision that allows for non-compliance if circumstances are beyond the control of the utility. The law specifically places the burden of proof on the utility, to prove that after subtracting "unavoidable surcharge for construction or environmental expenditures of generation," the cost of generating electricity under the AEPS will be 3 percent more than without complying with the mandate.[3] However, since the law contains annual increases in the mandate, it allows the electricity costs due to the mandate to rise by 3 percent per year. Thus, the provision effectively allows electricity prices to rise by 60.5 percent between 2008 and 2025 due to the AEPS compliance costs. Furthermore the cost cap excludes the "unavoidable surcharge" in the calculation of AEPS costs, but includes them in the calculation of the non-compliance cost scenario, in effect pushing down the cost of compliance. These two factors render the cost control components of the AEPS ineffective and meaningless.

Most renewable electricity sources are more costly and unreliable than conventional energy sources such as coal and natural gas, and stand little chance of commercial success in a

[1] Ibid.
[2] Ibid. Also U.S. Energy Information Administration. Ohio Renewable Energy Profile. http://www.eia.gov/cneaf/solar.renewables/page/state_profiles/ohio.html.
[3] Ibid.

competitive market. In response, producers of renewable energy seek to guarantee a market through legislation similar to the AEPS. But whatever the market offers in terms of renewable energy, it will always be limited. In order to keep the electricity grid in equilibrium, intermittent resources such as wind and solar power need reliable back-up sources. If the wind dies down, or blows too hard (which trips a shutdown mechanism in commercial windmills), another power source must be ramped up instantly.

Not unlike taxes, higher electricity prices produce negative effects on economic activity, since one is paying a higher price for electricity without an increase in the value of that electricity. Prosperity and economic growth depend upon access to reliable and competitively priced energy. Consumers will have limited opportunity to avoid these costs. For low-income consumers, these higher electricity prices will force difficult choices between energy and other necessities such as such as clothing and shelter.

In this report, the American Tradition Institute commissioned the Beacon Hill Institute (BHI) to estimate the costs of the AEPS mandate and the economic impact of the legislation on the state economy. To that end, BHI applied its STAMP® models (State Tax Analysis Modeling Program) to estimate the economic effects of the state AEPS mandate.

Results

A wide variety of cost estimates exist for renewable electricity sources. The U.S. Energy Information Administration (EIA), a division of the Department of Energy, provides estimates for the cost of conventional and renewable electricity generating technologies. A literature review shows that in most cases the EIA's projected costs are at the low end of the range of estimates while the EIA's capacity factor for wind to be at the high end of the range.[4] The EIA appears to overlook the actual experience of existing renewable electricity power plants.

In measuring the effects of the AEPS on the Ohio economy, we account for the effects of the RPS and AES. The RPS mandate increases by 0.25 percent per year until it reaches 12.5 percent in 2025, which we calculate the cost for each year from 2016 to 2025. The AES does not ramp up similarly; it simply requires 12.5 percent of all electricity be produced from advanced energy sources by 2025. Due to the costs and lead times associated with implementation of AES, such as clean coal and nuclear, we follow the letter of the law and assume that the generation units are completed in 2025, when the full 12.5 percent is implemented.[5] We also assume the AES mandate is satisfied through clean coal and nuclear power generation, since these are the only sources that can produce electricity in industrial quantities.

[4] The capacity factor measures the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period.
[5] Details on the methodology used can be found in the Appendix.

In light of the wide divergence in the costs and capacity factor estimates available for the different electricity generation technologies, we provide three estimates of the effects of Ohio AEPS mandate using low, average and high cost projections of both renewable and conventional generation technologies. Each estimate represents the change that will take place in the indicated variable against the assumption that the AEPS mandate would not be implemented. The Appendix details our methodology. Table 1 displays our estimates.

Table 1: The Cost of the AEPS Mandate on Ohio (2010 $)

Costs Estimates	Low	Medium	High
Total Net Cost in 2025 ($ m)	262	1,427	2,373
Total Net Cost 2016-2025 ($ m)	5,220	8,629	10,929
Electricity Price Increase in 2025 (cents per kWh)	0.18	0.97	1.61
Percentage Increase	1.7%	9.3%	15.4%
Economic Indicators			
Total Employment (jobs)	(2,480)	(9,753)	(15,523)
Gross Wage Rates ($ per Worker)	(61)	(334)	(556)
Investment ($ m)	(15)	(79)	(132)
Real Disposable Income ($ m)	(201)	(1,097)	(1,824)

The results for the low cost scenario are substantially lower than the other two. This divergence is primarily due to the EIA's projections that costs of nuclear and clean coal will fall dramatically over the next 15 years. See Table 5 in the Appendix. The AEPS will impose costs of $1.427 billion in 2025, within a range of $262 million and $2.373 billion. For the period of 2016 – 2025 the AEPS mandate will cost $8.629 billion, with a low estimate of $5.22 billion and a high estimate of $10.929 billion. As a result, the AEPS mandate will increase electricity prices by 0.97 cents per kilowatt-hour (kWh), or by 9.3 percent, within a range of 0.18 cents per kWh, or by 1.7 percent, and 1.61 cents per kWh, or by 15.4 percent.[6]

Upon full implementation, the AEPS law will reduce economic output in Ohio. Ratepayers will face higher electricity prices, which will increase the cost of living and the cost of doing business in the state. By 2025 Ohio will employ 9,753 fewer workers than without the AEPS policy, within an estimated range of 2,480 and 15,523 workers.

The decrease in labor demand — as seen in the job losses — will cause gross wages to fall. In 2025 the Ohio AEPS will reduce annual wages by $334 per worker, within a range of $61 and $556 per worker.

[6] We converted the aggregate cost of the RPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, for 2025 under the average cost scenario above, we divided $1,427 million into 147,058 million kWhs for a cost of 0.97 cents per kWh.

The job losses and price increases will reduce real incomes as firms, households and governments are forced to allocate more resources to purchase electricity and less to purchase other items. In 2025 annual real disposable income will fall by $1.097 billion, within a range of $201 million and $1.824 billion under our low and high cost scenarios respectively.

Net investment will fall by $79 million in 2025, within a range of $15 million and $132 million. The relatively moderate investment losses will be offset by the investments required to build renewable power plants, transmission lines and reconfigurations to the electricity grid. However, these investments are not as productive as the ones based on conventional energy because the renewable mandate works its way through the production methods less efficiently. A good analogy would be applying a mandate to telecommunications. An AEPS is akin to requiring that 25 percent of all Internet access to comprise of dial-up service over telephone service lines. Business would indeed be good for dial-up modem manufacturers, and Internet Service Providers would need to retrofit their networks, but this investment would not increase productivity in the economy.

Table 2 shows how the AEPS will affect the annual electricity bills of households and businesses in Ohio. In 2025 the AEPS will cost families on average $123 per year; commercial businesses on average of $867 per year; and industrial businesses on average $31,024 per year. Between 2016 and 2025 the average household ratepayer will pay $756 in higher electricity costs; the average commercial ratepayer will spend an extra $5,350; and the average industrial ratepayer an extra $191,490.

Table 2: Effects of the AEPS on Electricity Ratepayers (2010 $)

Cost in 2025	**Low**	**Medium**	**High**
Residential Ratepayer ($)	22	123	204
Commercial Ratepayer ($)	159	867	1,441
Industrial Ratepayer ($)	5,695	31,024	51,596
Total over period (2016-2025)			
Residential Ratepayer ($)	402	756	1,013
Commercial Ratepayer ($)	2,841	5,350	7,166
Industrial Ratepayer ($)	101,685	191,490	256,507

One could justify the higher electricity costs if the environmental benefits, in terms of reduced GHG emissions, outweighed the costs. But it is unclear that the use of renewable energy resources, especially wind and solar, significantly reduces GHG emissions. Due to their intermittency, wind and solar require significant backup power sources that are cycled up and down to accommodate the variability in their production. As a result, wind power could actually increase pollution and greenhouse gas emissions, according to a recent study.[7] Thus the case for the heavy use of wind to generate "cleaner" electricity is undermined.

[7] See "How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market," BENTEK Energy, LLC. (Evergreen Colorado: May, 2010).

Conclusion

The rush to renewable energy found in AEPS mandates in states across the nation is flawed. The policy promotes certain forms of renewable energy — expensive ones — at the cost of other, more affordable and dependable sources. The Ohio law is no different. On the surface, the cost caps included in the Ohio law appear reasonable. However, a detailed examination reveals that the cost cap provision will allow Ohio's electricity prices to rise by 65.5 percent due to the AEPS. The cost caps will not protect electricity ratepayers from higher utility prices or the state economy from employment losses, diminished investment, and lower incomes. Moreover, the environmental benefits of wind and solar power are illusionary since both forms of energy require readily available backup power generation sources.

The Ohio AEPS law requires the state's Public Utilities Commission to file an annual compliance report that includes a section pertaining to "any strategy for utility and company compliance or for encouraging the use of alternative energy resources in supplying this state's electricity needs in a manner that considers available technology, costs, job creation, and economic impacts."[8] The evidence presented in this report shows that the impacts are decidedly negative.

The Ohio AEPS puts the state's competitiveness at risk. These costs will result in slower economic growth for Ohio in the future, and it will fall behind competitor states. Policymakers should pay careful attention to the real dangers posed by higher electricity prices and repeal the mandate at the first opportunity. At the very least, lawmakers should amend the law to require the PUC annual compliance report to include a cost/benefit analysis section.

[8] Ohio Revised Code, Title [49] XLIX PUBLIC UTILITIES, » Chapter 4928: COMPETITIVE RETAIL ELECTRIC SERVICE, paragraph D1, http://codes.ohio.gov/orc/4928.64 (accessed February 15, 2011).

Appendix

Electricity Generation Costs

As noted above, governments enact Renewable Portfolio Standard policies because most sources of renewable electricity generation are less efficient and thus more costly than conventional sources of generation. The RPS policy forces utilities to buy electricity from renewable sources and thus guarantees a market for the renewable source. These higher costs get passed on to all electricity consumers: residential, commercial and industrial.

The U.S. Department of Energy's Energy Information Administration (EIA) estimates the Levelized Energy Cost (LEC), or financial breakeven cost per MWh, to produce new electricity in its *Annual Energy Outlook*.[9] The EIA provides LEC estimates for conventional and renewable electricity technologies (coal, nuclear geothermal, landfill gas, solar photovoltaic, wind and biomass) assuming the new sources enter service in 2016. The EIA also provides LEC estimates for conventional coal, combined cycle gas, advanced nuclear and onshore wind only, assuming the sources enter service in 2020 and 2035.

While the EIA does not provide LEC for hydroelectric, solar photovoltaic and biomass for 2020 and 2035, it does project overnight capital costs for 2015, 2025 and 2035. We can estimate the LEC for these technologies and years using the percent change in capital costs to inflate the 2016 LECs. In its *Annual Energy Outlook*, the EIA incorporates many assumptions about the future price of capital, materials, fossil fuels, maintenance and capacity factor into their forecast. Table 3 on the following page shows over time the EIA projects that the LEC for all four electricity sources (coal, gas, nuclear and wind) fall significantly from 2016 to 2035. The fall in capital costs drives the drop in total system LEC over the period.

The EIA estimates that wind generation will benefit from lower transmission and maintenance costs. EIA forecasts that transmission costs for wind will drop from $8.4 per MWh in 2016 to $5.6 per MWh, or by 33 percent, between 2020 and 2035. Fixed operations and maintenance costs will drop from $11.4 per MWh to $8.9 per MWh, or by 22 percent, over the same period. The drop in capital, maintenance and transmission costs combine to reduce wind power cost from $149.3 per MWh to $78.9 per MWh, or by an astounding 47.2 percent over the period. By 2035, wind would become the third least expensive behind biomass and natural gas.

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[9] U.S. Department of Energy, Energy Information Administration, *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (accessed September 20, 2010).

Table 3: Levelized Cost of Electricity from Conventional and Renewable Sources (2008 $)

Plant Type	Capacity Factor	Levelized Capital Costs	Fixed O&M	Variable O&M (with fuel)	Transmission Investment	Total Levelized Cost
Advanced Coal - 2016	0.850	81.2	5.3	20.4	3.6	110.5
2020		77.1	5.3	19.6	3.6	105.6
2035		55.9	5.3	20.2	3.5	84.9
Gas - 2016	0.870	22.9	1.7	54.9	3.6	83.1
2020		21.4	1.6	53.7	3.6	80.3
2035		15.6	1.6	54	3.7	74.9
Nuclear -2016	0.900	94.9	11.7	9.4	3.0	119.0
2020		86.9	11.7	9.9	3.0	111.5
2035		60.9	11.7	11.6	3.0	87.2
Wind - 2016	0.344	130.5	10.4	0.0	8.4	149.3
2020		81.6	8.9	0.0	5.6	96.1
2035		64.4	8.9	0.0	5.6	78.9
Solar PV - 2016	0.217	376.8	6.4	0.0	13.0	396.1
2025						297.7
2035						208.6
Biomass -2016	0.830	73.3	9.1	24.9	3.8	111.1
2025						62.8
2035						47.5
Hydro -2016	0.514	103.7	3.5	7.1	5.7	119.9
2025						101.3
2035						83.4

Using the EIA change in overnight capital costs for solar and biomass produces reductions in LECs similar to wind from 2016 to 2035. The biomass LEC drops by 57.3 percent and solar by 47.3 percent over the period. These compare to much more modest cost reductions of 23.1 percent for coal, 9.9 percent for gas, and 26.7 percent for nuclear over the same period. EIA does provide overnight capital costs for renewable technologies under a "high cost" scenario. However, for each renewable technology the EIA "high cost" scenario projects capital costs to drop between 2015 and 2035.

Moreover the building of vast wind power plants will require large quantities of raw materials, particularly aluminum and other commodities. The rising demand for these commodities – from the construction of renewable energy plants and from fast growing emerging market economies – will certainly increase their prices and therefore costs for wind power plants. Aluminum prices have doubled over the past two years as the world economy struggles to emerge from the recession.[10] As a result capital and other costs are more likely to rise than fall over the next two decades.

Table 3 also displays capacity factors for each technology. The capacity factor measures the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period. In this case, the capacity factor measures the potential productivity of the generating technology. Solar, wind and hydroelectricity have the lowest capacity factors due to the intermittent nature of their power sources. EIA projects a 34.4 percent capacity factor for wind power, which, as we will see below, appears to be at the high end of any range of estimates.

Estimating a capacity factor for wind power is particularly challenging. Wind is not only intermittent but its variation is unpredictable, making it impossible to dispatch to the grid with any certainty. This unique feature of wind power argues for a capacity factor rating of close to zero. Nevertheless, wind capacity factors have been estimated to be between 20 percent and 40 percent.[11] The other variables that affect the capacity factor of wind are the quality and consistency of the wind and the size and technology of the wind turbines deployed. As the U.S. and other countries add more wind power over time, presumably the wind turbine technology will improve, but the new locations for wind power plants will likely have diminishing or less productive wind resources.

The EIA estimates of LEC and capacity factors paint a particularly rosy view of the future cost of renewable electricity generation, particularly wind. Other forecasters and the experience of current renewable energy projects portray a less sanguine outlook.

Today wind and biomass are the largest renewable power sources and are the most likely to satisfy future RPS mandates. The most prominent issues that will affect the future availability and cost of renewable electricity resources are diminishing marginal returns and competition for scarce resources. These issues will affect wind and biomass in different ways as state RPS mandates ratchet up over the next decade.

Both wind and biomass resources face land use issues. Conventional energy plants can be built within a space of several acres and can be located close to large population centers with high electricity demand. However, a wind power plant with the same nameplate capacity (not actual capacity) would require many square miles of land. According to one study, wind power would require 7,579 miles of mountain ridgeline to satisfy current state RPS mandates

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[10] MetalPrices.com, "LME Aluminum Price Charts," http://www.metalprices.com/FreeSite/metals/al/al.asp#MoreCharts (accessed January 2011).

[11] Renewable Energy Research Laboratory, University of Massachusetts at Amherst, "Wind Power, Capacity Factor and Intermittency: What Happens When the Wind Doesn't Blow?" Community Wind Power Fact Sheet #2a, http://www.ceere.org/rerl/about_wind/RERL_Fact_Sheet_2a_Capacity_Factor.pdf (accessed December, 2010).

and a 20 percent federal mandate by 2025.[12] Mountain ridgelines produce the most promising locations for electric wind production in the eastern and far western United States.

After taking into account capacity factors, a wind power plant would need a land mass of 20 by 25 kilometers to produce the same energy as a nuclear power plant that can be situated on 500 square meters.[13]

The need for large areas of land for situating wind power plants will require the purchase of vast areas of land by private wind developers and/or allowing wind production on public lands. In either case land acquisition/rent or public permitting processes will likely increase costs as wind power plants are built. Offshore wind is vastly more expensive than onshore wind power and suffers from the same type of permitting process faced by onshore wind power plants, as seen in the 10-year permitting process for the planned Cape Wind project off the coast of Massachusetts.

The swift expansion of wind power will also suffer from diminishing marginal returns as new wind capacity will be located in areas with lower and less consistent wind speeds. As a result, fewer megawatt hours of power will be produced from newly-built windmills. Moreover the new wind capacity will be developed in increasing remote areas that will require larger investments in transmission and distribution, which will drive costs even higher.

The EIA estimates of the average capacity factor used for onshore wind power plants, at 34.4 percent, appears to be at the higher end of the estimates for current wind projects. This figure is inconsistent with estimates from other studies.[14] According to the EIA's own reporting from 137 current wind power plants in 2003, the average capacity factor was 26.9 percent.[15] In addition, a recent analysis of wind capacity factors around the world finds an actual average capacity factor of 21 percent.[16] Moreover, other estimates find capacity factors in the mid teens and as low as 13 percent.[17]

Biomass is a more promising renewable power source. Biomass combines low incremental costs relative to other renewable technologies and reliability. Biomass is not intermittent and therefore it is distributable with a capacity factor that is competitive with conventional energy

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[12] Tom Hewson and Dave Pressman, "Renewable Overload: Waxman-Markey RES Creates Land-use Dilemmas," *Public Utilities Fortnightly* 61 (August 1, 2009).

[13] "Evidence to the House of Lords Economic Affairs Committee Inquiry into 'The Economics of Renewable Energy'," Memorandum by Dr. Phillip Bratby, May 15, 2008.

[14] Nicolas Boccard, "Capacity Factors for Wind Power: Realized Values vs. Estimates," *Energy Policy* 37, no. 7 (July 2009): 2680.

[15] Cited by Tom Hewson, Energy Venture Analysis, "Testimony for East Haven Windfarm," January 1, 2005, http://www.windaction.org/documents/720 (accessed December 2010).

[16] Boccard.

[17] See "The Capacity Factor of Wind, Lightbucket," http://lightbucket.wordpress.com/2008/03/13/the-capacity-factor-of-wind-power/, (accessed December 22, 2010) and National Wind Watch, FAQ, http://www.wind-watch.org/faq-output.php (accessed December 2010).

sources. Moreover biomass plants can be located close to urban areas with high electricity demand. But biomass electricity suffers from land use issues even more so than wind.

The expansion of biomass power plants will require huge additional sources of fuel. Wood and wood waste comprise the largest source of biomass energy today. Other sources of biomass include food crops, grassy and woody plants, residues from agriculture or forestry, oil-rich algae, and the organic component of municipal and industrial wastes.[18] Biomass power plants will compete directly with other sectors (construction, paper, furniture) of the economy for wood and food products and arable land.

One study estimates that 66 million acres of land would be required to provide enough fuel to satisfy the current state RPS mandates and a 20 percent federal RPS in 2025.[19] When the clearing of new farm and forestlands are figured into the GHG production of biomass, it is likely that biomass increases GHG emissions.

The competition for farm and forestry resources would not only cause biomass fuel prices to skyrocket, but also cause the prices of domestically-produced food, lumber, furniture and other products to rise. The recent experience of ethanol and its role in surging corn prices can be casually linked to the recent food riots in Mexico and the surge in hunger in the Darfur region of Sudan. These two examples serve as reminders of the unintended consequences of government mandates for biofuels. The lesson is clear: biofuels compete with food production and distort the market.

Calculation of the Net Cost of New Renewable Electricity

To calculate the cost of renewable energy under the AEPS, BHI used data from the Energy Information Administration (EIA), a division of the U.S. Department of Energy, to determine the percent increase in utility costs that Ohio residents and businesses would experience. This calculated percent change was then applied to calculated elasticities, as described in the STAMP modeling section.

We collected historical data on the retail electricity sales by sector from 1990 to 2008 and projected its growth through 2025 using its historical compound annual growth rate (3.6 percent).[20] To these totals, we applied the percentage of renewable sales prescribed by the Ohio AEPS. By 2025, renewable energy sources must account for 25 percent of total electricity sales in Ohio.

[18] Biomass Energy Basics, National Renewable Energy Laboratory, Biomass Basics, http://www.nrel.gov/learning/re_biomass.html (accessed December, 2010).
[19] Hewson, 61.
[20] U.S. Department of Energy, Energy Information Administration, Ohio Electricity Profile 2010, "Table 5: Electric Power Industry Generation by Primary Energy Source, 1990 through 2008," http://www.eia.doe.gov/cneaf/electricity/st_profiles/Ohio.html. (accessed January 2011).

Next we projected the growth in renewable sources that would have taken place absent the AEPS. We used the EIA's projection of renewable energy sources by fuel for the East Central Area Reliability Coordination Agreement Power Area through 2025 as a proxy to grow renewable sources for Ohio. We used the growth rate of these projections to estimate Ohio's renewable generation through 2025 absent the AEPS. [21]

We subtracted our baseline projection of renewable sales from the AEPS-mandated quantity of sales for each year from 2016 to 2025 to obtain our estimate of the annual increase in renewable sales induced by the AEPS in megawatt hours (MWhs). The AEPS mandate exceeds our projected renewable in all projected years (2016 to 2025). This figure also represents the maximum number of MWhs of electricity from conventional sources that are avoided, or not generated, through the AEPS mandate. We will revisit this shortly. Table 4 contains the results.

Table 4: Projected Electricity Sales, Eligible Renewables and Required under RPS

Year	Projected Electricity Sales MWhs (000s)	Eligible Renewable MWhs (000s)	RPS Requirement MWhs (000s)	Difference MWhs (000s)
2016	140,878	756	6,340	5,584
2017	142,792	756	7,854	7,098
2018	144,691	756	9,405	8,649
2019	143,779	756	10,783	10,028
2020	142,862	756	12,143	11,388
2021	141,942	756	13,484	12,729
2022	143,232	756	15,039	14,284
2023	144,515	756	16,619	15,863
2024	145,790	756	18,224	17,468
2025	147,058	756	18,382	17,626
Total	1,437,539	7,558	128,274	120,716

To estimate the cost of producing the additional extra renewable energy under an AEPS against the baseline, we used estimates of the LEC, or financial breakeven cost per MWh to produce the electricity.[22] However, as outlined in the "electricity generation cost" section above, the EIA numbers provide a rather optimistic picture of the cost and generating capacity

[21] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2010,* "Table 92: Renewable Electricity Generation by Fuel," http://www.eia.doe.gov/oiaf/archive/aeo10/aeoref_tab.html (accessed January 2010).
[22] U.S. Department of Energy, Energy Information Administration, *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (accessed September 2010).

of renewable electricity, particularly for wind power. A literature review provided alternative LEC estimates that were generally higher and capacity factors that were lower for renewable generation technologies than the EIA estimates.[23] We used these alternative figures to calculate our "high" LEC estimates and the EIA figures to calculate our "low" cost estimates and the average of the two to calculate our "average" cost estimates. Table 5 displays the LEC and capacity factors for each generation technology.

Table 5: LEC and Capacity Factors for Electricity Generation Technologies

	Capacity Factor (percent)	Total Production Cost (cents/MWh) 2010	2020	2025
Coal				
Low	74.0	67.41	64.82	63.53
Average	79.5	83.96	85.21	79.39
High	85.0	100.50	105.60	95.25
Gas				
Low	85.0	75.86	73.25	73.25
Average	86.0	79.48	76.77	75.42
High	87.0	83.10	80.30	77.60
Nuclear				
Low	90.0	76.94	59.20	49.33
Average	90.0	97.97	85.35	74.34
High	90.0	119.00	111.50	99.35
Biomass				
Low	83.0	113.90	103.54	98.36
Average	75.5	112.50	95.27	80.62
High	68.0	111.10	86.99	62.88
Wind				
Low	34.4	287.67	269.54	251.40
Average	26.9	201.22	188.54	175.85
High	15.5	148.78	96.10	87.50

[23] For coal, gas and nuclear generation we used the production cost estimates from the International Energy Agencies, Energy Technology Analysis Programs, "Technology Brief E01: Cola Fired Power, E02: Gas Fired Power, E03: Nuclear Power and E05: Biomass for Heat and Power," (April 2010), http://www.etsap.org/E-techDS/ (accessed December 2010). To the production costs we added transmission costs from the EIA using the ratio of transmissions costs to total LEC costs. For wind power we used the IEA estimate for levelized capital costs and variable and fixed O & M costs. For transmission cost we used the estimated costs from several research studies that ranged from a low of $7.88 per kWh to a high of $146.77 per kWh, with an average of $60.32 per MWh. The sources are as follows:
Andrew Mills, Ryan Wiser, and Kevin Porter, "The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies," Ernest Orlando Lawrence Berkeley National Laboratory, http://eetd.lbl.gov/EA/EMP (accessed December 2010); Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study, The Electric Reliability Council of Texas, April 2, 2008 http://www.ercot.com/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf (accessed December 2010); Sally Maki and Ryan Pletka, Black & Veatch, California's Transmission Future, August 25, 2010, http://www.renewableenergyworld.com/rea/news/article/2010/08/californias-transmission-future (accessed December 22, 2010).

We used the 2016 LEC for the years 2010 through 2018 to calculate the cost of the new renewable electricity and avoided conventional electricity, assuming that before 2016 LEC underestimates the actual costs for those years and for 2017 and 2018, the 2016 LEC slightly overestimates the actual costs. We assumed that the differences would, on balance, offset each other. For 2019 and 2020 we used the 2020 LEC. The assumption is that LEC will decline over time due to technological improvements over time.

We use the EIA's reference case scenario for all technologies. Since capital costs represent the large component of the cost structure for most technologies, we used the percentage change in the capital costs from 2016 to 2025 to adjust the 2016 LECs to 2025. For the technologies that the EIA does not forecast LECs in 2020, we used the average of the 2016 and 2025 LEC calculations, assuming a linear change over the period.

Once we computed new LECs for the years 2020 and 2025 we applied these figures to the renewable energy estimates for the remainder of the period.

For conventional electricity we assumed that the technologies are avoided based on their costs, with the highest cost combustion turbine avoided first. For coal and gas, we assumed they are avoided based on their estimated proportion of total electric sales for each year. Although hydroelectric and nuclear are not the cheapest technology, we assume no hydroelectric or nuclear sources are displaced since most were built decades ago and offer relatively cheap and clean electricity today.

We also adjusted the avoided cost of conventional energy to account for the lower capacity factor of wind relative to conventional energy sources. We multiplied the cost of each conventional energy source by the difference between its capacity factor and the capacity factor for the renewable source, and then by the ratio of the new generation of the renewable source to the total new generation of renewable under the AEPS. For example, for coal, we multiplied the avoided amount generation of electricity from coal (15.102 million MWhs in 2025) by the LEC of coal ($79.39 per MWh) and then by one minus the difference between the capacity factor of coal and the weighted average (using MWs as weights) capacity factor of wind (27 percent). This process is repeated for each conventional electricity resource.

These LECs are applied to the amount of electricity supplied from renewable sources under the AEPS, because this figure represents the amount of conventional electricity generation capacity that presumably will not be needed under the AEPS. The difference between the cost of the new renewable sources and the costs of the conventional electricity generation Ohio represents the net cost of the AEPS. Tables 6, 7 and 8 on the following pages display the results of our Average, Low and High Cost calculations respectively.

We converted the aggregate cost of the AEPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, in 2025 under the average cost scenario in Table 6, we divided $1.427 million into 147.058 million kWhs for a cost of 0.97 cents per kWh.

Table 6: Average Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	640,053	159,736	480,317
2017	813,605	203,052	610,553
2018	991,433	247,433	744,001
2019	1,149,449	286,869	862,580
2020	1,036,689	321,571	715,118
2021	1,158,790	359,446	799,345
2022	1,300,342	403,353	896,988
2023	1,444,168	447,967	996,201
2024	1,590,240	493,277	1,096,963
2025	1,604,669	497,753	1,106,916
Total	**11,729,439**	**3,420,456**	**8,308,983**

Table 7: Low Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	628,556	256,756	371,800
2017	798,991	326,379	472,612
2018	973,625	397,715	575,910
2019	1,128,802	461,104	667,699

2020	994,660	538,994	455,666
2021	1,111,811	602,476	509,335
2022	1,247,624	676,072	571,552
2023	1,385,620	750,850	634,770
2024	1,525,769	826,795	698,974
2025	1,539,614	834,297	705,316
Total	**11,335,073**	**5,671,438**	**5,663,634**

Table 8: High Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	658,952	101,244	557,708
2017	837,629	128,698	708,931
2018	1,020,708	156,828	863,881
2019	1,183,390	181,823	1,001,567
2020	1,073,642	212,553	861,089
2021	1,200,096	237,588	962,508
2022	1,346,693	266,610	1,080,082
2023	1,495,646	296,099	1,199,547
2024	1,646,925	326,048	1,320,876
2025	1,661,869	329,007	1,332,862
Total	**12,125,550**	**2,236,499**	**9,889,051**

The Advanced Energy Source (AES) section of the law was calculated using a slightly different methodology. The law does not include a step-up requirement, unlike the RPS section, but does include a language requiring 12.5 percent of energy be produced by advanced energy sources by 2025. For this reason, we only considered costs that would be incurred in 2025, leading to our results being a minimum should AES be required prior to 2025.

Using Ohio Public Utility Commission estimates, energy sales in 2025 would be 145,790,000 MWh, meaning that 18,223,750 MWh of energy would need to come from advanced energy sources, as defined by the AEPS laws.[24] Due to the raw size of this requirement, we believe that the source will likely come from two types of power plants that the law specifically mentions: new nuclear power and clean coal.

Our assumption is that each advanced power source would account for 50 percent of the mandate, or 9,111,875 MWH. Applying the same cost per MWh methodology as used for the RPS, we determined the cost, in 2025 of the AES section of the AEPS law. This cost was combined with the calculated cost of the RPS, to determine the percentage increase in the cost of electricity, which was then used to determine the ratepayer and economic effects.

Ratepayer Effects

To calculate the effect of the AEPS on electricity ratepayers, we used EIA data on the average monthly electricity consumption by type of customer: residential, commercial and industrial.[25] The monthly figures were multiplied by 12 to compute an annual figure. We inflated the 2008 figures for each year using the average annual increase in electricity sales over the entire period.[26]

We calculated an annual per-kWh increase in electricity cost by dividing the total cost increase – calculated in the section above — by the total electricity sales for each year. We multiplied the per-kWh increase in electricity costs by the annual kWh consumption for each type of ratepayer for each year. For example, we expect the average residential ratepayer to consume 12,629 kWhs of electricity in 2025 and we expect the average cost scenario to raise electricity costs by 0.97 cents per kWh in the same year in our average cost case. Therefore, we expect residential ratepayers to pay an additional $123 in 2025.

Modeling the AEPS using STAMP

We simulated these changes in the STAMP model as a percentage price increase on electricity to measure the dynamic effects on the state economy. The model provides estimates of the

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[24] Ohio Public Utility Commission. Estimated Quantification of Statewide Compliance Obligations Associated with Renewable Energy Component of the Alternative Energy Portfolio Standard. http://www.puco.ohio.gov/emplibrary/files/util/EnergyEnvironment/SB221/aeps%20estimate.pdf

[25] U.S. Department of Energy, Energy Information Administration, "Average electricity consumption per residence in MT in 2008," (January 2010) http://www.eia.doe.gov/cneaf/electricity/esr/table5.html, The 2008 consumption figures were inflated to 2010 using the increase in electricity demand from the EIA of 0.89 percent compound annual growth rate.

[26] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2010*, "Table 8: Electricity Supply, Disposition, Prices, and Emissions," http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html. (accessed December 22, 2010).

proposals' impact on employment, wages and income. Each estimate represents the change that would take place in the indicated variable against a "baseline" assumption of the value that variable for a specified year in the absence of the AEPS policy.

Because the AEPS requires Ohio households and firms to use more expensive "advance" power than they otherwise would have under a baseline scenario, the cost of goods and services will increase under the AEPS. These costs would typically manifest through higher utility bills for all sectors of the economy. For this reason we selected the sales tax as the most fitting way to assess the impact of the AEPS. Standard economic theory shows that a price increase of a good or service leads to a decrease in overall consumption, and consequently a decrease in the production of that good or service. As producer output falls, the decrease in production results in a lower demand for capital and labor.

BHI utilized its STAMP (State Tax Analysis Modeling Program) model to identify the economic effects and understand how they operate through a state's economy. STAMP is a five-year dynamic CGE (computable general equilibrium) model that has been programmed to simulate changes in taxes, costs (general and sector-specific) and other economic inputs. As such, it provides a mathematical description of the economic relationships among producers, households, governments and the rest of the world. It is general in the sense that it takes all the important markets, such as the capital and labor markets, and flows into account. It is an equilibrium model because it assumes that demand equals supply in every market (goods and services, labor and capital). This equilibrium is achieved by allowing prices to adjust within the model. It is computable because it can be used to generate numeric solutions to concrete policy and tax changes.[27]

In order to estimate the economic effects of the AEPS we used a compilation of six STAMP models to garner the average effects across various state economies: New York, North Carolina, Washington, Kansas, Indiana and Pennsylvania. These models represent a wide variety in terms of geographic dispersion (Northeast, Southeast, Midwest, The Plains and West) economic structure (industrial, high-tech, service and agricultural) and electricity sector makeup.

First, we computed the percentage change to electricity prices as a result of three different possible AEPS policies. We used data from the EIA from the state electricity profiles, which contains historical data from 1990-2008 for retail sales by sector (residential, commercial, industrial, and transportation) in dollars and MWhs and average prices paid by each sector.[28] We inflated the sales data (dollars and MWhs) though 2020 using the historical growth rates

[27] For a clear introduction to CGE tax models, see John B. Shoven and John Whalley, "Applied General-Equilibrium Models of Taxation and International Trade: An Introduction and Survey," *Journal of Economic Literature* 22 (September, 1984): 1008. Shoven and Whalley have also written a useful book on the practice of CGE modeling entitled Applying General Equilibrium (Cambridge: Cambridge University Press, 1992).

[28] U.S. Department of Energy, Energy Information Administration, Ohio Electricity Profile 2010, Table 8: Retail Sales, Revenue, and Average Retail Price by Sector, 1990 through 2008, http://www.eia.doe.gov/cneaf/electricity/st_profiles/Ohio.html (accessed January 2011).

for each sector for each year. We then calculated a price for each sector by dividing the dollar value of the retails sales by kWhs. Then we calculated a weighted average kWh price for all sectors using MWhs of electricity sales for each sector as weights. To calculate the percentage electricity price increase we divided our estimated price increase by the weighted average price for each year. For example, in 2025 for our average cost case we divided our average price of 10.47 cents per kWh by our estimated price increase of 0.97 cents per kWh for a price increase of 9.26 percent.

Using these three different utility price increases – 1 percent, 4.5 percent and 5.25 percent – we simulated each of the six STAMP models to determine what outcome these utility price increases would have on each of the six state's economy. We then averaged the percent changes together to determine what the average effect of the three utility increases. Table 9 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state of Ohio discussed above.

Table 9: Elasticities for the Economic Variables

Economic Variable	Elasticity
Employment	-0.022
Gross wage rates	-0.063
Investment	-0.018
Disposable Income	-0.022

We applied the elasticities to percentage increase in electricity price and then applied the result to Ohio economic variables to determine the effect of the AEPS. These variables were gathered from the Bureau of Economic Analysis Regional and National Economic Accounts as well as the Bureau of Labor Statistics Current Employment Statistics.[29]

[29] See the following: Bureau of Economic Analysis, "National Economic Accounts," http://www.bea.gov/national/; Regional Economic Accounts, http://www.bea.gov/regional/index.htm. See also Bureau of Labor Statistics, "Current Employment Statistics ," http://www.bls.gov/ces/.

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Introduction to the Input-Output Model Framework and how it is Used to Estimate the Economic Impacts of Increased Electric Costs in Ohio

1. Mathematics of the Input-Output Framework[1]

An input-output framework begins with observed transaction data for a particular region. For example, the IMPLAN model is constructed from data at the national, state, and county levels. The transactions are typically converted into dollar amounts, as that makes tracing economic flows much easier, since dollars are a uniform measure.

We assume that the economy is made of up of numerous sectors, e.g., manufacturing, mining, agriculture, services, government, and foreign trade. To construct an input-output table, we record how the output produced (supplied) by a given sector, such as steel, is purchased by (demanded) the other industry sectors (who then use those purchased inputs to manufacture other goods), plus external sales to government and consumers. Thus, if there the economy consists of N industries, the total output produced by an individual industry, X_k, will be purchased by the other N–1 industries, used by itself, and sold to final consumers. Thus,

$$X_k = z_{k,1} + z_{k,2} + z_{k,3} + \ldots + z_{k,N} + Y_k \tag{1}$$

where the $z_{i,n}$ are sales to each industry n, and Y_k equals sales for final demand (i.e., to consumers, the government, and for export). Since we have N industries, we can write the entire set of flows as

$$\begin{bmatrix} X_1 = z_{1,1} + z_{1,2} + \ldots + z_{1,k} + \ldots + z_{1,N} + Y_1 \\ X_2 = z_{2,1} + z_{2,2} + \ldots + z_{2,k} + \ldots + z_{2,N} + Y_2 \\ \vdots \\ X_k = z_{k,1} + z_{k,2} + \ldots + z_{k,k} + \ldots + z_{k,N} + Y_k \\ \vdots \\ X_N = z_{N,1} + z_{N,2} + \ldots + z_{N,k} + \ldots + z_{N,N} + Y_N \\ \end{bmatrix} \tag{2}$$

Each column of coefficients on the right-hand side of equation (2), i.e.,

[1] For a far more detailed discussion, see Leontief, *op. cit*. See also, R. Miller and P. Blair, *Input-Output Analysis: Foundations and Extensions*, (Englewood Cliffs, NJ: Prentice-Hall 1985), Chp. 2.

$$\begin{bmatrix} z_{1,k} \\ z_{2,k} \\ \vdots \\ z_{k,k} \\ \vdots \\ z_{N,k} \end{bmatrix}$$

represents the purchases from industry sector k to the N–1 other industry sectors, and to itself ($z_{k,k}$). In other words, industry k purchases inputs from all of the other industries to produce output X_k. When all of the N different columns are combined, they create an *input-output table*, with each selling sector a different row, and each purchasing sector a different column, as shown in Table 1.

Table 1: An Input-Output Table

		Purchasing industry sector					
		1	**2**	**…**	**K**	**…**	**N**
	1	$Z_{1,1}$	$Z_{1,2}$	…	$Z_{1,k}$		$Z_{1,N}$
Selling	**2**	$Z_{2,1}$	$Z_{2,2}$	…	$Z_{2,k}$		$Z_{2,N}$
Industry	⋮	⋮	⋮		⋮		⋮
Sector	**k**	$Z_{k,1}$	$Z_{2,k}$	…	$Z_{k,k}$		$Z_{N,k}$
	⋮	⋮	⋮		⋮		⋮
	N	$Z_{N,1}$	$Z_{N,2}$	…	$Z_{N,k}$		$Z_{N,N}$

Although the input-output table above incorporates all of the inter-industry sales and purchases, it does not account for the remainder of the economy. For example, final demand includes sales to consumers, state, local, and the federal government, investment, and exports. Moreover, in addition to buying outputs from other industries, each industry pays wages to its employees (W), pays for government services (in the form of taxes), pays for capital (in the form of interest payments, I), and profits. Together, these components are called *value-added*. On top of that, each sector imports goods and services from outside the economy. For example, if building a new high-voltage transmission line requires buying substation equipment from Germany, then the input-output model for the U.S. would consider that an import.

The input-output framework assumes that production coefficients are fixed. This means that there are specific quantities of inputs required to produce a given output. Thus, building a car—any car—is assumed to take (say) 2000 pounds of steel, 100 pounds of rubber, 200 pounds of glass, and so forth. Obviously, this assumption of fixed production coefficients does not hold true entirely—the amount of materials needed to build a large pick-up truck is greater than that needed to built a subcompact car—but for estimating short-run impacts, the overall assumption is reasonable: building more cars and trucks will clearly require more steel, producing more steel will require more iron ore, and so forth.

Because the input-output framework assumes fixed production coefficients (called a "Leontief production function"), the necessary inputs needed to produce a unit of output are all constant. If we divide the purchases made by industry k from every industry, i.e., the $z_{i,k}$, to produce output X_k, we derive the *technical coefficients,* $a_{i,k}$, for industry k. In other words,

$$a_{i,k} = \frac{Z_{i,k}}{X_k} \tag{3}$$

If we substitute equation (3) into equation (2), we obain:

$$\begin{bmatrix} X_1 = a_{1,1}X_1 + a_{1,2}X_2 + \ldots + a_{1,k}X_k + \ldots + a_{1,N}X_N + Y_1 \\ X_2 = a_{2,1}X_1 + a_{2,2}X_2 + \ldots + a_{2,k}X_k + \ldots + a_{2,N}X_N + Y_2 \\ \vdots \\ X_k = a_{k,1}X_1 + a_{k,2}X_2 + \ldots + a_{k,k}X_k + \ldots + a_{k,N}X_N + Y_n \\ \vdots \\ X_N = a_{N,1}X_1 + a_{N,2} + \ldots + a_{N,k}X_k + \ldots + a_{N,N}X_N + Y_N \end{bmatrix} \tag{4}$$

What equation (4) tells us is that some of the output produced by an industry is sold to all other industries and used in fixed quantities to produce those industries' outputs, and the remainder is sold as final demand to consumers, government, and as exports. As a final step, we isolate the final demands for the output from each industry, Y_k. Thus,

$$\begin{bmatrix} X_1 - a_{1,1}X_1 + a_{1,2}X_2 + \ldots + a_{1,k}X_k + \ldots + a_{1,N}X_N = Y_1 \\ X_2 - a_{2,1}X_1 + a_{2,2}X_2 + \ldots + a_{2,k}X_k + \ldots + a_{2,N}X_N = Y_2 \\ \vdots \\ X_k - a_{k,1}X_1 + a_{k,2}X_2 + \ldots + a_{k,k}X_k + \ldots + a_{k,N}X_N = Y_n \\ \vdots \\ X_N - a_{N,1}X_1 + a_{N,2} + \ldots + a_{N,k}X_k + \ldots + a_{N,N}X_N = Y_N \end{bmatrix} \tag{5}$$

Equation (5) lies at the heart of the economic impact analysis, because it allows us to answer the question, "If the demand for the output of industry k changes, by how much would the output of all of the other industries change?" For example, building a new high-voltage transmission line would increase the demand for concrete, steel, and so forth. How will these changes in demand ripple through the Ohio economy and what will be the final changes in output levels in all other industries, as well as the change in total labor (i.e., jobs) and income?

To answer this sort of question, we solve equation (5) for each of the X_i. This requires a bit of matrix algebra. It turns out that the solution can be written as

$$\mathbf{X} = (\mathbf{I} - \mathbf{A})^{-1}\mathbf{Y} \tag{6}$$

where

$$\mathbf{A} = \begin{bmatrix} a_{1,1} \cdots a_{1,N} \\ a_{2,1} \cdots a_{2,N} \\ \vdots \\ a_{k,1} \cdots a_{k,N} \\ \vdots \\ a_{N,1} \cdots a_{N,N} \end{bmatrix}, \qquad \mathbf{X} = \begin{bmatrix} X_1 \\ X_2 \\ \vdots \\ X_k \\ \vdots \\ X_N \end{bmatrix}, \qquad \mathbf{Y} = \begin{bmatrix} Y_1 \\ Y_2 \\ \vdots \\ Y_k \\ \vdots \\ Y_N \end{bmatrix}$$

The matrix $(\mathbf{I} - \mathbf{A})^{-1}$ is called the *Leontief inverse*. By changing the level of final demand in the output vector **Y** and knowing the technical coefficients $a_{i,k}$, we can determine the flows through the economy.

There are three types of economic impacts typically evaluated in an input-output study: *direct*, *indirect*, and *induced*. Direct effects are those that are a direct result of an increase in demand for good k. For example, building a new high-voltage transmission line will require concrete for the tower foundations. Thus, the demand for concrete will increase. That is a *direct* impact. Increasing the demand for concrete, however, will require concrete manufacturers to increased their purchases of all of the inputs used to manufacture concrete, including sand, gravel, electricity, and so forth, thus increasing the demand for all of those inputs. Thus, the *direct* increase in the demand for concrete *indirectly* increases the demand for all of these other products. Finally, all of these manufacturers pay wages to employees. Those employees, in turn spend a portion of their wages on food, electricity, new cars, and so forth. As a result, we say the resulting consumer spending from households *induces* further increases in demand, and thus additional economic impacts.

Because of the interconnections among industries and between industries and households, an increased demand for just one good or service is said to cause *ripple effects* throughout the economy. These ripple effects lead to additional jobs and increases disposable income as workers are hired, equipment and supplies are purchased from other local businesses, wages are paid to employees, and taxes are paid to government entities. These impacts are called *multiplier effects* or *multipliers*. For example, if the demand for concrete increases by \$1 million and the overall impact on the Ohio economy is \$2 million, then the output multiplier equals \$2million/\$1 million = 2.0. We can also calculate jobs and income multipliers. For example, if 100 workers are hired to construct a transmission line, and the overall ripple effects lead to 50 new jobs created as a result, the employment multiplier will equal 150/100 = 1.5.

2. Estimating economic impacts

Ripple effects act like waves bouncing off walls. Eventually, each subsequent round of impacts decreases in magnitude, just like a wave bouncing off walls eventually subsides. The speed at which these ripple effects diminish, and the overall magnitude of multipliers, depends on what are called *leakages* out of an economy. For example, not all of the materials needed to build the transmission line will be purchased from Ohio companies. Moreover, some of the workers hired to construct the project may be from outside the state. Furthermore, Ohio workers who are hired will not spend all of their wages within the state, but will instead buy goods and services from neighboring states, too. As we discuss in the sections that follow, assumptions about *leakage rates*, i.e., what fraction of spending occurs outside Ohio, are crucial in estimating the overall economic impacts to the state.

a. Calculating multipliers[2]

Multipliers are calculated from the Leontief inverse matrix defined previously. For example, suppose we have an economy with just two industries, industry **X** and industry **Y**, with the following technical coefficients matrix.

$$\mathbf{A} = \begin{bmatrix} 0.15 & 0.25 \\ 0.20 & 0.05 \end{bmatrix} \tag{7}$$

What this means is that to produce \$1 of additional output, industry **X** purchases \$0.15 from itself and \$0.20 from industry **Y**. The remaining \$0.65 is accounted for through valued added – wages and salaries paid to employees, taxes paid to federal, state, and local governments, and profits. Similarly, to produce \$1 of additional output, industry **Y** purchases \$0.25 from industry **X**, \$0.05 from itself, and the remaining \$0.70 is value added. It turns out the Leontief inverse matrix (ignoring the value added impacts) is

$$(\mathbf{I} - \mathbf{A})^{-1} = \begin{bmatrix} 1.254 & 0.33 \\ 0.264 & 1.122 \end{bmatrix} \tag{8}$$

The values in the Leontief inverse provide the output multipliers, by adding up each column. Specifically, if there is a \$1 increase in final demand for the output of industry **X**, then the total increase in demand for output of industry **X** is \$1.254 - \$1 for the increase in final demand, and \$0.254 for inter-industry and intra-industry use. There is also an *indirect* increase in demand of

2 For a much more detailed discussion, see Miller and Blair, fn. 1, from which these examples are drawn.

\$0.264 of industry **Y** for inter-industry and intra-industry use. Thus, if we sum down the first column, a \$1 increase in demand for industry **X** leads to a total increase in output of \$1.254 + \$0.264 = \$1.518. The output multiplier for industry **X** is thus \$1.518/\$1 = 1.518. Because we are not considering households in this example, this output multiplier is called a *Type I* multiplier.

Next, we consider household impacts, such as from wages paid to households. Suppose that industry 1 **X** pays \$0.30 in wages per dollar of output and that industry 2 pays \$0.25 in wages per dollar of output. By incorporating these payments into the technical coefficients matrix, we can determine the direct, indirect, and *induced* impacts from increased output. So, we rewrite the technical coefficients matrix as follows:

$$\mathbf{A} = \begin{bmatrix} 0.15 & 0.25 & 0.05 \\ 0.20 & 0.05 & 0.40 \\ 0.30 & 0.25 & 0.05 \end{bmatrix} \qquad (\mathbf{I}-\mathbf{A})^{-1} = \begin{bmatrix} 1.365 & 0.425 & 0.251 \\ 0.527 & 1.348 & 0.595 \\ 0.570 & 0.489 & 1.289 \end{bmatrix} \tag{9}$$

The new technical coefficients matrix **A** now contains 3 rows and 3 columns. The 2x2 matrix of values in the top left hand corner is the original matrix shown in equation (7). The third column represents households. So, in the example, households spend \$0.05 per dollar buying items from industry **X**, \$0.40 per dollar buying items from industry **Y**, and \$0.05 buying items from within the household sector. (The remainder is spent paying taxes and for investment.). The third row shows that industry **X** spends \$0.30 per dollar on wages, while industry **Y** spends \$0.25 per dollar on wages.

When we calculate the new Leontief inverse $(\mathbf{I}-\mathbf{A})^{-1}$, the first thing to notice is that the previous coefficients (the top-left 2x2 matrix) are all larger than they were in equation (8). This is because we are now including household demand impacts. Now, the output multiplier for industry **X** is the sum of the first column [1.365, 0.527, 0.570], or 2.462. Thus, for every \$1 increase in demand in industry **X**, total output in the local economy increases by \$2.462. The output multiplier for industry **X** is therefore 2.4262. In matrix notation, the output multiplier for industry *i* in our N-industry economy is:

$$M_{output,i} = \mathbf{i}_i \bullet (\mathbf{I}-\mathbf{A})^{-1} \bullet \mathbf{i}_i', \tag{10}$$

where $\mathbf{i}_i = \begin{bmatrix} 0 & \cdots & 1_j & \cdots & 0 \end{bmatrix}$.[3]

In our 2-industry example, we can calculate the household income multiplier for industry **X** in several ways. The first is to treat household spending as outside our model and estimate impacts using the Type 1 multipliers. To do that, we go back to the initial Leontief inverse in equation (8)

3 In other words, $\mathbf{i}_j$ is a 1xN unit vector having value 1 for industry j. The term $\mathbf{i}_j'$is called the *transpose* of $\mathbf{i}_i$, and is a Nx1 column vector.

and multiply the household income coefficients in **A** for our two industries (the third row) by the first column in the Leontief inverse, and add the results, i.e.,

$$H_X = (0.30)(1.254) + (0.25)(0.264) = 0.442$$

What this means is that, for every $1 increase in demand for the output of industry **X**, total household income increase by $0.442 because of the direct and indirect economic impacts on output. Thus, the *Type 1 multiplier* is $0.442/$0.30 = 1.47.

If we include the economic impact caused by households also spending money in the economy, the result is called a *Type II multiplier*. To do this, we use the new **A** and $(\mathbf{I}-\mathbf{A})^{-1}$ matrices shown above. For industry **X**, we calculate the total household income change, including the within-household sector impacts and divide by $0.30 that industry 1 pays directly to households in the form of wages. Thus, we have

$$H'_X = (0.30)(1.365) + (0.25)(0.527) + (0.05)(0.57) = 0.570$$

and the multiplier is $H'_X/0.30$ = $0.57/$0.30 = 1.9. Note also that the overall household impact, $0.57 is just the value in the last row of the Leontief inverse matrix for industry **X**.

Finally, we estimate *employment multipliers*, following the same approaches previously outlined. Only this time, the multipliers do not reflect dollar changes, but changes in employment. To do this, one determines the number of employees (in full-time equivalents) per dollar of output in each industry. For example, suppose for each million dollars of output produced in industry **X**, 300 employees are required, and that in industry 2, 400 employees are used per million dollars of output. This translates to values of 0.003 and 0.004 employees per dollar in industries **X** and **Y**, respectively. Similarly, assume the household sector requires 100 employees per million dollars of output, or 0.001 employees per dollar. Then, using the Leontief inverse matrix in equation (9), we calculate the total employment impact for industry **X** as

$$E'_X = (0.003)(1.365) + (0.004)(0.527) + (0.001)(0.570) = 0.000572$$

Then, using the same approach as for calculating the Type II income multipliers, we can calculate the Type II employment multiplier for industry 1 as $E'_X/0.0003$ = 1.907. Thus, for every job added in industry **X**, a total of 1.907 jobs are added in the entire economy.

3. The IMPLAN Model

IMPLAN was first developed in the 1970s by the U.S. Forest service to analyze the economic impacts of different forestry policies. The current version of IMPLAN is maintained by the University of Minnesota IMPLAN group. IMPLAN provides a detailed breakdown of the U.S. economy, with over 500 separate economic sectors. IMPLAN is widely used by numerous government agencies, including at the federal and state levels.

The IMPLAN model begins with the most current national transactions matrix developed by the current National Bureau of Economic Analysis Benchmark Input-Output Model. Next, the model creates state and county-level values by adjusting the national level data, such as removing industries that are not present in a particular state or economy. The model also estimates imports using what are called *regional purchase coefficients* (RPCs). RPCs measure the proportion of the total supply of a good or service required to meet a particular industry's intermediate demands and final demands that are produced locally. The larger the RPC value, the greater the percentage of total regional demand that is met through local supplies.

In addition to calculating standard Type I and Type II multipliers, IMPLAN can also calculate what are called "SAM multipliers." SAM stands for "Social Accounts Matrix," and is a more detailed breakdown of transactions within an economy. Specifically, whereas the typical input-output framework captures production and consumption, it leaves out some income transactions, such as taxes, savings, and transfer payments. IMPLAN allows users to capture these components as well, and thus derive what are called SAM multipliers.[4] SAM multipliers are a form of Type II multiplier. Thus, SAM multipliers incorporate direct, indirect, and induced impacts, while accounting for the effects of savings, taxes, and transfer payments.

4. Estimating the economic impacts of higher electric prices

To estimate the overall economic impacts of the higher wholesale electric prices and higher capacity market costs, we assumed a short-run elasticity of zero. That is, we assumed consumers would not, initially, reduce their electric consumption in response to the slightly higher electric prices they faced. Since consumer income is assumed to be fixed in the short run, this implies consumers must reduce their expenditures on all other goods and services (including savings and investment) by an equivalent amount.

Similarly, we assumed that in-state businesses would react to the increased price of electricity by reducing their total output such that their aggregate production expenses remained unchanged. This assumption is consistent with the assumption of fixed production coefficients in the Leontief model. It also assumes that businesses would not be able to pass on the increased production costs to consumers.

b. Estimating the total impacts on state output

With these assumptions, we estimate the overall change in output as follows. First, we calculate a weighted-average *regional purchase coefficient* for output in the Ohio economy, excluding

4 For complete discussion of how SAM multipliers are derived, see G. Alward, "Deriving SAM multipliers using IMPLAN," paper presented at the 1996 National IMPLAN Users Conference, Minneapolis, MN, August 15–17, 1996, 1996. Available at: http://implan.com/v3/index.php?option=com_docman&task=doc_download&Itemid=138&gid=127.

electric power. A regional purchase coefficient (RPC) equals the fraction of local demand for a good or service that is satisfied from local production. For example, in Ohio, about 47% of all ready-mix concrete was purchased from in-state manufacturers, based on 2008 data. The weighted RPC, RPC_{OH}, equals the sales-weighted average of the individual sector RPCs, excluding the electric generation sector (assumed to be sector *k*). Thus,

$$RPC_{OH} = \frac{\sum_{i=1, i\neq k}^{N} Q_i \cdot RPC_i}{\sum_{i=1, i\neq k}^{N} Q_i} \tag{11}$$

Similarly, we calculate the weighted-average SAM output multiplier, $\bar{M}_{OH}^{output}$, using the output from each industry as the individual industry weights. Thus, using equation (10) for the output multiplier for industry i, we have

$$\bar{M}_{OH}^{output} = \sum_{i=1, j\neq k}^{N} Q_i \cdot \{\mathbf{i_i} \bullet (\mathbf{I} - \mathbf{A})^{-1} \bullet \mathbf{i_i}'\} / \Delta Q_{OH}^{TOT} = \sum_{i=1, j\neq k}^{N} Q_i \cdot M_{output,i} / \Delta Q_{OH}^{TOT}, \tag{12}$$

The total impact on output in the state, ΔQ_{OH}^{TOT}, will equal the weighted RPC times the weighted output multiplier, times the estimated increase in total electric expenditures. Thus, if the total change in electric expenditures is ΔQ_{ELEC}, we have:

$$\Delta Q_{OH}^{TOT} = \Delta Q_{ELEC} \cdot RPC_{OH} \cdot \bar{M}_{OH}^{output} \tag{13}$$

c. Estimating the total impact on state employment

We can follow a similar procedure to estimate the total impacts on state employment arising from the higher electric expenditures, with the additional step of estimating the weighted average employment per million dollars of output, using the employment multipliers calculated by IMPLAN. Thus, the weighted jobs per million dollars of output can be written as:

$$\bar{J}_{OH} = \sum_{i=1, i\neq k}^{N} Q_i \cdot J_i / \Delta Q_{OH}^{TOT}, \tag{14}$$

where J_i is jobs per million dollars of output in industry *i*. Therefore, the overall weighted jobs multiplier is:[5]

[5] The jobs multiplier is just the output multiplier weighted by jobs per million dollars of output.

$$\bar{M}_{OH}^{jobs} = \sum_{i=1, i \neq k}^{N} Q_i \cdot J_i \{ \mathbf{i_i} \bullet (\mathbf{I} - \mathbf{A})^{-1} \bullet \mathbf{i_i}' \}, \tag{15}$$

And so, the total impact on jobs in the state from the increased expenditures on electricity will equal:

$$\Delta J_{OH}^{TOT} = (\Delta Q_{ELEC} \cdot RPC_{OH}) \cdot (\bar{J}_{OH} \cdot \bar{M}_{OH}^{jobs}) \tag{16}$$