Large Filing Separator Sheet

Case Number: 11-346-EL-SSO

File Date: 6/11/2012

Section: 2 of 2

Number of Pages: 68

Description of Document: Exhibit

0352-EL-AIR supported by AEP Ohio witness Avera. Unlike the other formula inputs that will be updated annually, AEP Ohio proposes that the ROE remain fixed for the term that this rate is applicable, absent any appropriate regulatory filing or filings to modify the ROE.

Q. PLEASE DESCRIBE THE THIRD CAPACITY MODIFICATION.

A. The capacity formula rates are traditionally reconciled for other wholesale customers between the rates charged and revenues collected during a period and the actual costs incurred by the seller during that same period, computed after the fact. This is performed by collecting or crediting the difference between these revenues and actual costs in a subsequent period, commonly referred to as a "true-up". This is appropriate for the other wholesale customers so that no under- or over-collection occurs and the seller ultimately collects the precise costs incurred to serve these customers. However, the formula rates for other wholesale customers are generally applied under long-term contracts.

Because it would be impractical and administratively burdensome to perform such a true-up with CRES providers, who can enter and leave the market at will and are likely to have load that is changing over the period due to customer switching, AEP Ohio is not proposing any such reconciliation. This results in a benefit to CRES providers as well since it would not result in a source of uncertainty regarding their capacity rate over the period.

In other words, as an example, the 2011 FF1 actual accounting data will be used to determine the capacity rate charged to CRES providers for the PJM PY 2012/2013 with no subsequent reconciliation or true-up. This will provide rate certainty for CRES providers during the planning year. However, since there is no true-up, the lag between the historic costs and actual costs for the rate-effective period should be minimized as much as practical. Consequently, AEP Ohio ~~CSP and OPCo~~ proposes to utilize only the end-of-year rate base balances for the formula calculations rather than average annual values from the historic period. The end-of-year rate base balances will be closer to the rate base in effect during the applicable PJM PY than an average rate base which uses more dated balances. Even this end-of-year balance may potentially understate the average rate base for the PJM PY in which these capacity rates are in effect.

ENERGY CREDIT

Q. IS AEP OHIO PROPOSING AN ENERGY CREDIT AS ON OFFSET TO THE CAPACITY RATES?

A. No, it is not.

Q. WHY IS SUCH AN ENERGY CREDIT OFFSET UNWARRANTED?

A. PJM has completely separated the markets for capacity and energy in contrast to traditional generation sources that combine the sourcing of enough power to satisfy the peak and on-going customer demands, measured in MegaWatts (MWs) or kiloWatts (kWs) with enough of that power integrated over time to satisfy customers' energy requirements, measured in MegaWatt-hours (MWhs) or kiloWatt-hours (kWhs). As a result, obtaining capacity through PJM's RPM market or through a FRR plan does not provide any rights or a call option on energy at any price. Energy must be separately procured by all PJM load-serving entities. Consequently, the capacity rates proposed by AEP Ohio are appropriate for charging CRES providers.

Q. IF THE PUBLIC UTILITIES COMMISSION OF OHIO SHOULD CHOOSE TO ADOPT AN ENERGY CREDIT, DO YOU HAVE ANY COMMENTS REGARDING HOW SUCH A CREDIT SHOULD BE DETERMINED?

A. Yes I do. While AEP Ohio is not proposing an energy credit, it is ~~only~~ proposing a methodology to be used should the Commission choose to adopt such a credit. In addition to the formula rate template proposed by AEP Ohio for capacity, ~~the Companies have~~AEP Ohio has also included a template for the calculation of the energy costs, including fuel, used to serve formula rate customers' energy requirements. This calculation can be easily adapted for the purpose of determining the amount of such an energy credit if such a capacity rate reduction is adopted by this Commission. It is part of the same template accepted by FERC for the Cities of Minden and Prescott and therefore is consistent with the capacity portion of the formula and has also undergone the same regulatory scrutiny.

Q. HOW WOULD SUCH AN ENERGY CREDIT BE DETERMINED?

A. The formula rate templates are generally offered to customers under long term, multi-year agreements for full requirements service and therefore require these other wholesale customers to purchase energy for their own load at a rate tied to the applicable operating company's energy cost. Such a right and obligation will not exist for CRES providers once they become the Load Serving Entity (LSE) for shopping customers. CRES providers compensate AEP Ohio for the Companies' capacity in only one-year, short-term, increments. AEP Ohio's proposal is straightforward. Simply put, the energy credit is the difference between market-based revenues and the Companies' energy cost.

Q. PLEASE EXPLAIN.

A. The credit is calculated as the difference between the revenues that the CSP and OPCo historic load shapes, including all shopping and non-shopping load, would be valued at using the hourly Locational Marginal Prices (LMP) that settle in the PJM Day-Ahead (DA) market, less the cost-basis of this energy. The 2010 energy cost-basis rates are provided in Exhibits KDP-1 through KDP-4. The energy credit revenues and final energy credit are provided in KDP-5.

Q. PLEASE DESCRIBE THE REVENUE CALCULATION.

A. The previous year's hourly load for ~~CSP and OPCo~~ AEP Ohio would be collected following the end of a given year along with the hourly AEP GenHub prices based on the actual PJM DA LMPs. The total market-based revenue is simply the product of the hourly loads and the hourly LMPs summed across the entire year. This represents a fair and reasonable proxy for the energy revenue that could have been obtained by CSP and OPCo by selling equivalent generation into the market rather than utilizing it to directly serve load.

Q. WHY DID ~~CSP AND OPCO~~ AEP OHIO SELECT THE ENTIRE LOAD SHAPE OF SHOPPING AND NON-SHOPPING LOAD?

A. First, attempting to provide an individual energy credit for each CRES provider for the load they serve would be administratively burdensome and extremely difficult to compute on an ongoing basis. In addition, given that there will be a lag between the time period for which the energy credit is computed and the time period to which it is applied, it would provide gaming opportunities for CRES providers.

Q. PLEASE DESCRIBE THE COST BASIS OF THE ENERGY.

A. The cost basis is ~~would be~~ the energy rate computed using the same formula rates described for capacity, which provides for a consistent and straightforward solution. All of the formula rate benefits described previously during the capacity discussion apply equally well to energy -- they provide the same level of transparency and have already undergone, and easily accommodate, regulatory scrutiny.

Q. IS AEP OHIO PROPOSING ANY MODIFICATIONS TO THE ORIGINAL TEMPLATES USED FOR SUCH AN ENERGY COST COMPUTATION?

A. Yes. AEP Ohio is proposing the following two modifications to the template used for the other- wholesale customers if an energy credit is adopted:

- no deferrals of costs, and
- no off-system sales (OSS) margin sharing.

Q. PLEASE DESCRIBE THE FIRST MODIFICATION TO THE ENERGY TEMPLATE~~MODIFICATION~~.

A. From an economic dispatch perspective, the cost-basis of the energy credit should be the actual, non-deferred cost, particularly of fuel. No consideration should be given for fuel costs that are deferred for later collection. This most accurately reflects the actual commercial operation of AEP Ohio's generation units in the PJM energy market. As a consequence, this also would lead to the most accurate determination of a suitable proxy for the energy value of the load shape associated with the CSP and OPCo loads. It would eliminate timing differences between when deferrals are incurred and when they are recovered. For long-term contracts, customers likely incur both sides of the transaction. For CRES providers, their load may vary greatly from period to period and elimination of the deferrals will ensure that they would neither be advantaged nor disadvantaged by the timing differences of such deferrals and subsequent recoveries.

Q. PLEASE DESCRIBE THE SECOND MODIFICATION TO THE ENERGY TEMPLATE~~MODIFICATION~~.

A. AEP Ohio would determine an energy credit for the load shape only, which makes this consistent with retail customers taking service under AEP Ohio's ~~CSP's and OPCo's~~ standard service offers. While it may be viewed by some as reasonable to provide an energy credit based on the AEP Ohio ~~CSP and OPCo~~ loads, it would not be reasonable to provide yet an additional credit for other sales that would be made beyond that load. As stated previously, the capacity component of the rate already includes a credit for other capacity sales. Consequently, CRES providers would not be charged for surplus capacity that may be utilized to generate other OSS.

Q. ONCE THE VALUE OF THE ENERGY BASED ON THE LOAD SHAPE IS COMPUTED, DOES AEP OHIO PROPOSE ANY ADJUSTMENTS TO THAT ENERGY CREDIT?

A. Yes. The energy value is computed as though it were the result of an incremental energy sale. Consequently, it would be appropriate to apply the same type of sharing to this value for purposes of obtaining and providing an energy credit if one is adopted.

First, the energy value of such a credit must be treated as though it were an OSS for purposes of sharing through the AEP Interconnection Agreement (IA). The IA requires that OSS are shared between the AEP operating companies that are part of this agreement. As a result, while AEP-Ohio retains the generation revenues from its non-shopping customers, it would only receive an allocated share from any resulting incremental energy sale. The IA allocator for such sales is the Member Load Ratio (MLR)~~ for CSP and OPCo~~.

Second, AEP Ohio ~~OPCo~~ would subsequently allocate a portion of its MLR-share of such an energy sale to the West Virginia jurisdiction due to its firm, full requirements wholesale contract with Wheeling Power Company, an AEP Operating Company.

Third, AEP Ohio proposes that any energy credit be further reduced by 50% to reflect the margin sharing percentage used above the base in the Minden and Prescott templates. CRES providers who purchase capacity on a year-to-year basis should not receive the full offset received by long term full requirements wholesale customers.

Q. SHOULD THERE BE ANY LIMITS TO THE ENERGY CREDIT IF IT IS ADOPTED?

A. Yes. The energy credit computed as described above should further be capped at 40% of the capacity charge that would be applicable with no energy credit. The reason for this is that in high price wholesale periods, the energy credit could get so large as to greatly reduce any capacity payment whatsoever from CRES providers. Such a result would be a clear subsidy to these CRES providers. Wholesale markets are volatile and the capacity rates proposed have a lag. Consequently, CRES providers could simply wait until a high energy price market period has come and gone and subsequently obtain capacity at extremely low rates due to an excessive energy credit, perhaps when the value of such energy is much lower.

In addition, the energy credit is only a proxy. AEP Ohio would utilize information from the previous year as though it did not serve the entire internal load of ~~CSP and OPCo~~ AEP Ohio and instead sold an equivalent hour-by-hour amount of energy into that market during the period. However, that clearly did not happen, at least up through 2011, since AEP Ohio did serve or is serving most of that energy. In a very strong wholesale market, retail choice may be less and AEP Ohio will serve much if not most of the load. Clearly, daily market-based revenues cannot be extracted from generation that is serving the AEP Ohio load. Consequently, applying no cap whatsoever could result in an overstated proxy for the energy credit, with the amount of the overstatement likely to correlate somewhat with the level of wholesale prices. In consideration of AEP Ohio's exposure to the variations in historic-versus-current pricing and amount of energy served without seeking any true-up, the energy credit cap and resulting capacity charge floor affords some protection for the Companies through the collection of at least 60% of the capacity costs they incur. In return, CRES providers may still get the benefit of very large energy credits for capacity.

Q. HOW WAS THE 40% CAP ON THE ENERGY CREDIT AND RESULTING 60% FLOOR ON THE CAPACITY CHARGE TO CRES PROVIDERS OBTAINED?

A. While AEP Ohio proposes no energy credit, the 40% energy credit cap and resulting 60% floor of the capacity rate were selected by AEP Ohio as fair and reasonable values if the Commission should adopt this credit. Further, as will be shown later, this level of credit cap represents more than twice the largest energy credit adjustment that has ever been determined for the computation of similar credits for new entrants in the PJM market.

PROPOSED CAPACITY RATES

Q. PLEASE PROVIDE THE CAPACITY COMPENSATION RATES PROPOSED BY THE COMPANIES.

A. The formula rate templates shown in Exhibits KDP-1 and KDP-2 have been populated with information from the 2010 CSP and OPCo FF1s. These populated templates are shown in Exhibits KDP-3 and KDP-4 for CSP and OPCo respectively. As seen on page 1 of Exhibits KDP-3 and KDP-4, the capacity compensation rates ~~proposed by the Companies~~ would have been ~~are~~ $327.59/MW-day for CSP and $379.23/MW-day for OPCo for the PJM PY 2011/2012. If approved by the Commission, ~~these capacity rates would be applicable for the remainder of the PJM PY 2011/2012 that runs through May 31, 2012. These~~ the AEP Ohio rates will be computed ~~would be updated~~ each spring as previously described for the subsequent PJM PY. The first applicable rate ~~update~~ would occur using 2011 FF1 information for the PJM PY that begins June 1, 2012.

Q. IF THE COMMISSION ADOPTS AN ENERGY CREDIT USING AEP OHIO'S METHODOLOGY, WHAT IS THE RESULTING ENERGY CREDIT?

A. The 2010 energy credits using the AEP Ohio methodology is shown in Exhibit KDP-5. As shown on page 2 of this Exhibit, the energy credits, ~~if adopted,~~ would have been $7.73/MW-day and $9.94/MW-day for CSP and OPCo respectively. These credits would have reduced the capacity rates to \$319.86/MW-day for CSP and \$369.29/MW-day for OPCo for the PJM PY 2011/2012.

Q. WHAT ARE THE IMPACTS ON THESE RATES DUE TO THE CSP AND OPCO MERGER?~~ARE THERE ANY OTHER BENEFITS THAT RESULT FROM THE PROPOSED RATES?~~

A. ~~Yes. Another benefit to AEP Ohio's proposal is that the individual Companies' rates can be easily combined into a single AEP Ohio rate. The Companies are currently seeking regulatory approval for their merger. If approved by the Commission, the rates can easily be combined to provide a single merged rate applicable to CRES providers. For example, a~~As shown in Exhibit KDP-6, the current merged rate would be \$355.72/MW-day. If the Commission were to adopt an energy credit using the AEP Ohio methodology, this rate would be reduced to \$338.14/MW-day. ~~Following the merger,~~ Beginning with 2011, AEP Ohio ~~would~~ill only file one FF1 and it would be the basis for computing the updated FRR capacity compensation rate beginning with the PJM PY 2012/2013.

~~In addition, AEP Ohio's Electric Security Plan (ESP) is currently under consideration by the Commission. This proposal includes various non-bypassable riders related to capacity costs. To the extent these riders are adopted by the Commission, some costs will be born directly by all end-use customers. In that event, the formula rates as proposed are well positioned to accommodate corresponding adjustments as necessary to ensure that any capacity-related amounts collected through non-bypassable riders are removed from the capacity charges. For example, any costs collected through the proposed non-bypassable Environmental Investment~~

~~Carrying Cost Rider (EICCR) would be removed from the CRES provider capacity charge. All such adjustments will be readily available for regulatory inspection.~~

RATE COMPARISONS

Q. WOULD YOU COMPARE THE PROPOSED RATES WITH THE PJM RATES?

A. Yes. The past, present and future RPM rates are shown in Table I below.

Table I - PJM Capacity Market Values
Values based on Unforced Capacity (UCAP) MW
All Capacity Values are expressed in $/MW-day

PJM Planning Year	Gross CONE ($/MW-day)	Net CONE ($/MW-day)	RPM BRA Clearing ($/MW-day)	Final Zonal Capacity Price[2] ($/MW-day)	Billed RPM Capacity Rate ($/MW-day)
2007/2008	197.29~~$210.26~~	$171.87	$40.80	$40.80	$46.73
2008/2009	197.83~~$210.73~~	$172.25	$111.92	$111.92	$129.71
2009/2010	197.83~~$210.73~~	$172.27	$102.04	$104.82	$126.33
2010/2011	197.83~~$210.93~~	$174.29	$174.29	$182.85	$220.96
2011/2012	197.29~~$210.35~~	$171.40	$110.00	$116.16	$145.79
2012/2013[1,3]	309.23~~$330.51~~	$276.09	$16.46	$16.52 [3]	$20.01 [3]
2013/2014[1]	334.89~~$357.41~~	$317.95	$27.73	TBD	$33.71
2014/2015[1]	351.30~~$374.72~~	$342.23	$125.99	TBD	$153.89

CONE = Cost of New Entry BRA= Base Residual Auction

Notes
[1]Future planning periods utilize preliminary scaling factors.
[2] Includes the affects of incremental auctions and ILR.
[3] Include the first and second incremental auction results but are not yet final.

Exhibit KDP-7 includes these same values along with various other PJM RPM market information, including the maximum potential clearing prices in the PJM Base Residual Auctions, based on 150% of Net Cost of New Entry (CONE). Exhibit KDP-7 also shows the standard PJM RPM adjustments used to convert the RPM Zonal Capacity Price into the effective billing rate, which is the appropriate RPM rate for comparisons to the proposed rate since these rates reflect what has been and would be the effective rate billed to CRES Providers.

The current capacity rate charged to CRES providers is shown in the last column of Table I above and column (l) of Exhibit KDP-7 and is $145.79/MW-day. This includes the initial Base Residual Auction clearing price of $110.00/MW-day adjusted to the Final Zonal Capacity Price of $116.16/MW-day due to the impacts of incremental auctions and Interruptible Load for Reliability, as well as the standard multipliers associated with the PJM RPM construct, including the scaling factor, forecast pool requirement and losses, to arrive at the current effective RPM billed capacity rate of $145.79/MW-day. Consequently the capacity rates proposed by AEP Ohio, based on the current PJM PY, would represent a 144~~25~~% ($355.72~~27.59~~/$145.79) increase~~ for CSP and a 160% ($379.23/$145.79) increase for OPCo~~.

It should be noted that, while the proposed capacity rates represents a large increases relative to the current and future RPM prices shown in column (l) of Exhibit KDP-7, the AEP Ohio proposed capacity rate~~s are~~ is much closer to the maximum rate that could have occurred in the current PY based on the PJM demand ~~supply~~ curve utilized. That value was $322.69/MW-day including all appropriate multipliers that ~~are currently~~ have been used to bill for capacity. Furthermore, the Maximum RPM rate used in the demand ~~supply~~ curve has increased~~s~~ dramatically and was $627.04/MW-day in the PJM PY 2014/2015 ~~most recent~~ auction, including the impacts of the PJM billing multipliers shown in Exhibit KDP-7.

In addition, the Net CONE value ~~i~~has trended~~ing~~ upward significantly. As shown in Table I and Exhibit KDP-7,- column (d), the $342.23/MW-day Net CONE value used for the PJM PY 2014/2015 RPM auction is nearly twice the $171.40/MW-day Net CONE value used for the current period auction. The most recent Net CONE value provided by PJM is still $320.63/MW-day. If one accepts the economically simplifying assumption referenced by AEP Ohio witness Horton that the RPM capacity prices will tend, on average, to clear near the NCONE value, then the ~~Companies'~~AEP Ohio proposed capacity compensation rates is within 11% of the ~~approach these same~~ Net CONE future values~~s~~.

Q. DO YOU HAVE ANY COMPARISONS TO MAKE REGARDING AEP OHIO'S PROPOSED CAP ON THE ENERGY CREDIT IF SUCH A CREDIT IS ADOPTED?

A. Yes. As mentioned earlier, AEP Ohio proposes that if the Commission adopts an energy credit, then the energy credit should be capped at no more than 40% of the capacity rate without the credit. As shown in Table I and Exhibit KDP-7, the ~~Gross-to-Net~~ energy ~~A~~adjustments (shown in column (e) in Exhibit KDP-7) are always less than 20% of the Gross CONE values (shown in column (c) of Exhibit KDP-7). This adjustment is the result of an energy credit being applied to the Gross CONE. Consequently, capping the AEP Ohio energy credit at 40% of the capacity rates without the energy credit will provide the potential for more than twice the energy adjustments that have thus far ever been made in reducing Gross CONE to Net CONE.

~~CRES PROVIDER SELF-SUPPLY OPTION~~

~~**Q. HOW WILL THE CRES PROVIDER SELF-SUPPLY OPTION BE ACCOMMODATED AND SETTLED?**~~

~~A. As stated previously, CSP's and OPCo's capacity rates are avoidable or by-passable by CRES providers if they supply capacity to meet their own loads prior to the Companies submitting their FRR plan three years prior to the delivery year.~~

~~**Q. IF A CRES PROVIDER COMMITS LESS CAPACITY THAN IT NEEDS FOR A GIVEN PJM PLANNING YEAR, HOW WILL THE COST OF THE SHORTFALL BE COMPENSATED?**~~

~~A. The cost of any shortfall would be addressed in the same manner as though the CRES provider did not provide any capacity. The MWs of the shortfall will be compensated at the Companies' proposed rates. For example, if a CRES provider serves 100 MW of capacity and chooses to self-supply none of it, the provider would pay for 100 MW at the proposed capacity rates. If the CRES Provider self-supplies 100 MW and then serves 150 MW during the PY, the CRES provider will compensate CSP and OPCo for 50 MW at the proposed capacity rates.~~

~~**Q. IF A CRES PROVIDER COMMITS MORE CAPACITY THAN IT SUBSEQUENTLY NEEDS FOR A GIVEN PJM PY FOR THE LOAD IT SERVES AND THE OBLIGATION REMAINS WITH OR GOES BACK TO CSP AND OPCO, HOW WILL CSP AND OPCO ACCOMMODATE THIS LOAD?**~~

~~A. If a CRES provider commits capacity to serve load, and then AEP Ohio must wind up serving a portion of that load as currently required, AEP Ohio will make their best~~

~~efforts to provide or obtain the shortfall capacity necessary to serve this load at the least expensive cost possible. This will benefit all customers.~~

~~**Q. SHOULD THE CRES PROVIDER WHO OVER-COMMITTED CAPACITY MAKE THIS CAPACITY AVAILABLE TO AEP OHIO?**~~

~~A. Yes. In the event of this scenario, since CSP and OPCo by direction of the CRES provider reduced their own capacity obligations and then subsequently are required to reacquire these obligations, the CRES provider should be obligated to make the capacity available to AEP Ohio. This availability should be in the form of a call option, which is the right, but not an obligation, to purchase this capacity from the CRES provider. The strike price of the call option, which is the price at which the transaction occurs if the holder of the call option elects to exercise it, should be the lower of the final RPM price or the applicable capacity rate of the Companies. In other words, AEP Ohio may unilaterally obtain the capacity from another source or purchase it from the CRES provider at the strike price.~~

~~**Q. WHY SHOULD THE STRIKE PRICE BE SET AT THE LOWER OF RPM PRICE OR THE CAPACITY RATE?**~~

~~A. The CRES provider may unilaterally, and with no input from AEP Ohio whatsoever, provide however much capacity that it believes it will serve during the applicable planning year. There should be no incentives for CRES providers to (a) supply capacity with which they have no earnest interest in serving load but instead commit it only to cause AEP Ohio to lower its own obligations and then (b) to sell this capacity to AEP Ohio when the Companies become short capacity for reasons created by the same CRES providers. Such actions, I believe, are not inconsistent with~~

~~actions alleged years ago in the California energy market that generation owners purposely withheld generation from the spot market only until the market was higher and then sold it back into that market. Similarly, CRES providers should not be given the incentive to purposely create a capacity shortage for AEP Ohio and then profit from it.~~

~~Consequently, AEP Ohio should be under no obligation to purchase the capacity, even at the strike price, if they can provide or acquire capacity less expensively. If capacity is not available at a lower rate, the CRES provider should be under the obligation to sell the surplus capacity to AEP Ohio at the lower of the RPM price or CSP's and OPCo's capacity rate if such capacity cannot be located at a less expensive price elsewhere. If AEP Ohio does not exercise the option to purchase the excess capacity from the CRES provider, the CRES provider may dispose of the surplus capacity in anyway it sees fit, such as selling it to a third party, provided such disposition is permitted by all applicable PJM and/or state rules. This combination would provide the most benefit to the Ohio customers.~~

~~Q. IS THIS TREATMENT CONSISTENT WITH THE REST OF THE CSP AND OPCO PROPOSAL?~~

~~A. Yes it is. Some may argue that the payments between CSP and OPCo and CRES providers for this capacity should somehow be "symmetrical" in that they should be at the same rate, whether it be at an RPM rate or a CSP and OPCo or other rate. The fact is that the obligations and opportunities of AEP Ohio and CRES providers regarding serving load are not symmetrical. CSP and OPCo *must* provide capacity for all of the loads within their service territories that CRES Providers *choose* not to~~

~~serve. Subsequently, CSP and OPCo then *must* accept back load obligations which CRES providers *choose* not to sign up during the applicable planning year for whatever reason.~~

~~Q. DOES AEP OHIO HAVE ANY PROPOSALS REGARDING THE ABILITY OF CRES PROVIDERS TO SELF-SUPPLY THEIR OWN CAPACITY?~~

~~A. In addition to the constraints described above, AEP Ohio proposes that each individual CRES provider be limited to supplying no more capacity for a given PJM PY than twice the capacity that is required to serve the load that the CRES provider is actually serving on January 1 of the year in which the FRR Plan for that planning year is submitted to PJM.~~

~~For example, if a CRES provider is currently serving load that requires 100 MW of capacity on January 1, 2012, that CRES provider may elect to self-supply up to 200 MW of capacity into the applicable FRR plan for the 2015/2016 PY that will be submitted during the first quarter of 2012. This limit would allow each CRES provider to self-supply approximately 25% more load each planning year.~~

~~OTHER ISSUES~~

~~Q. DO YOU HAVE ANY OTHER COMMENTS YOU WOULD LIKE TO MAKE ABOUT THE CSP AND OPCO FORMULA RATE PROPOSAL?~~

~~A. Yes. I understand that there is an open question regarding these capacity payments in terms of the appropriate jurisdictional forum, either this Commission or the FERC. While this appears to be a legal question best argued among the attorneys, it is my layman's understanding that much of these arguments may depend on whether these transactions are considered wholesale or retail.~~

~~Simply that I believe these to be wholesale transactions for capacity between AEP Ohio and the CRES providers. As such, it is hoped that, speaking from an operational rather than a legal viewpoint, the Commission will either affirm these transactions as wholesale and/or to designate them as wholesale transactions going forward.~~

~~Under AEP Ohio's proposal, CRES providers may self-supply their own capacity rather than obtain it from AEP Ohio as previously described. If these capacity transactions are designated as retail, it is assumed that the option to provide capacity, rather than purchase capacity from AEP Ohio, must then be eliminated. This is assumed since it is not clear how such an option could be accommodated if it is retail customers, rather than CRES providers, who are supplying their own capacity.~~

~~**Q. DO YOU HAVE ANY OTHER COMMENTS?**~~

~~A. Yes. CSP and OPCo were required to make an initial minimum five-year commitment under either RPM or FRR. Consequently, there is no cause for concern regarding AEP Ohio frequently moving between these two capacity options based on the applicable rates. Should the Companies choose to move to the RPM market, under the current PJM rules, it will be for a minimum of five years and cannot begin until the next auction period.~~

~~Further, for those who may suggest that AEP Ohio should move to RPM, this does not appear to me to be the forum to discuss such a move. Right now, PJM does allow a self-supply option, the Companies chose that option for reasons stated by AEP Ohio witness Horton, and AEP Ohio is currently locked into that option through~~

~~at least PJM PY 2014/2015. Attempting to include a lengthy debate into this proceeding on the appropriate past, present and future option for AEP Ohio, i.e., RPM or FRR, would simply cloud the fundamental question that must now be determined within the scope of this proceeding, namely, the appropriate reimbursement for the Companies for their own capacity provided to CRES providers while they are under the FRR plan.~~

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes it does.

PJM Capacity Market Values

Values based on Unforced Capacity (UCAP) MW

PJM PY (a)	RPM Reserve Margin Cleared (%) (b)	Gross CONE[4] ($/MW-day) (c)	Net CONE[5] ($/MW-day) (d)	Energy & AS Adjustment ($/MW-day) (e)	150% NCONE ($/MW-day) (f)=1.5x(d)	RPM BRA Clearing ($/MW-day) (g)	Final Zonal Capacity Price[2] ($/MW-day) (h)	Scaling Factor (i)	FPR (j)	Losses (k)	RPM Rate ($/MW-day) (l)=(h)x(i)x(j)x(k)	Maximum RPM Rate ($/MW-day) (m)=(f)x(i)x(j)x(k)
2007/2008	19.20%	$197.29	$171.87	($36.02)	$257.81	$40.80	$40.80	1.02635	1.07900	1.034126	$46.73	$295.24
2008/2009	17.50%	$197.83	$172.25	($36.12)	$258.38	$111.92	$111.92	1.03611	1.07960	1.034126	$129.71	$299.45
2009/2010	17.80%	$197.83	$172.27	($36.12)	$258.41	$102.04	$104.82	1.07964	1.07950	1.034126	$126.33	$311.44
2010/2011	16.50%	$197.83	$174.29	($34.36)	$261.44	$174.29	$182.85	1.07870	1.08330	1.034126	$220.96	$315.93
2011/2012	18.10%	$197.29	$171.40	($36.52)	$257.10	$110.00	$116.16	1.12037	1.08330	1.034126	$145.79	$322.69
2012/2013[1,3]	20.90%	$309.23	$276.09	($60.92)	$414.14	$16.46	$16.52	1.08177	1.08270	1.034126	$20.01	$501.60
2013/2014[1]	20.30%	$334.89	$317.95	($36.97)	$476.93	$27.73	TBD	1.08812	1.08040	1.034126	$33.71	$579.81
2014/2015[1]	20.60%	$351.30	$342.23	($30.46)	$513.35	$125.99	TBD	1.09276	1.08090	1.034126	$153.89	$627.04

PY = Planning Year
RPM = Reliability Pricing Model
CONE = Cost of New Entry
NCONE = Net Cost of New Entry
BRA= Base Residual Auction
FPR = Forecast Pool Requirement

Notes

1. Future planning periods utilize preliminary scaling factors.
2. Includes the affects of incremental auctions and ILR.
3. Columns h-m reflect the results of the 1st and 2nd incremental auctions but are not yet final
4. Gross CONE is stated on an Installed Capacity Basis.
5. Net CONE includes energy and ancillary services (AS) adjustment and forced outage adjustment.

RPM data sourced from the RPM Auction User Information page at: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY OF
DANA E. HORTON
ON BEHALF OF
~~COLUMBUS SOUTHERN POWER COMPANY~~
~~AND~~
OHIO POWER COMPANY

Filed: ~~August~~March 2~~1~~3, 201~~1~~2

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
DANA E. HORTON
ON BEHALF OF
~~COLUMBUS SOUTHERN POWER COMPANY~~
~~AND~~
OHIO POWER COMPANY

PERSONAL BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dana Earl Horton. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed as Director – RTO Policy in the Regulatory Services Department of American Electric Power Service Corporation (AEP). American Electric Power Service Corporation is agent for AEP Ohio, which is comprised of ~~Columbus Southern Power Company and~~ Ohio Power Company, hereby referred to as AEP or the Company.

Q. PLEASE PROVIDE YOUR EDUCATION AND WORKING CAREER BACKGROUND.

A. I graduated from Muskingum College in New Concord, Ohio, in 1979 with a Bachelor of Arts in Accounting. I also received a Masters of Business Administration from Miami (Ohio) University in 1980. I worked for Ernst & Whinney as a CPA from 1980-83 before I joined AEP in January 1984. During my tenure at AEP, I have held positions in the Controllers Department, Trading & Marketing, Commercial Operations, and most recently in Regulatory Services. My main responsibility since AEP joined PJM in 2004 has been as an advocate for AEP in the PJM stakeholder process. In this role I work extensively with the stakeholder process under which PJM transmission and market rules are established. As relevant to this testimony, I was part of the AEP team that participated in the PJM stakeholder process leading up to the adoption of the rules implementing the Reliability Pricing Model ("RPM") and the Fixed Resource Requirement ("FRR") that initially was developed in 2006. As one of the key members of the AEP negotiating team, I was present at the Federal Energy Regulatory Commission ("FERC") offices during each of the RPM/FRR settlement discussions. For the reasons I discuss below, AEP was at the center of the discussions around the FRR and was one of the most active participants in the stakeholder process that led up to the FRR rules at issue in this proceeding, including several key provisions in the PJM Tariff and PJM's Reliability Assurance Agreement ("RAA").[1]

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. The primary purpose of my testimony is to describe the RPM and FRR options to supply capacity, the development of the FRR and why AEP chose this option. In addition, I will provide background and explanations for certain provisions in the FRR procedures including the requirements for alternative retail suppliers (called CRES providers in Ohio) with respect to their capacity obligations.

Q. PLEASE EXPLAIN THE METHODS FOR SUPPLY AND PROCUREMENT OF CAPACITY IN PJM.

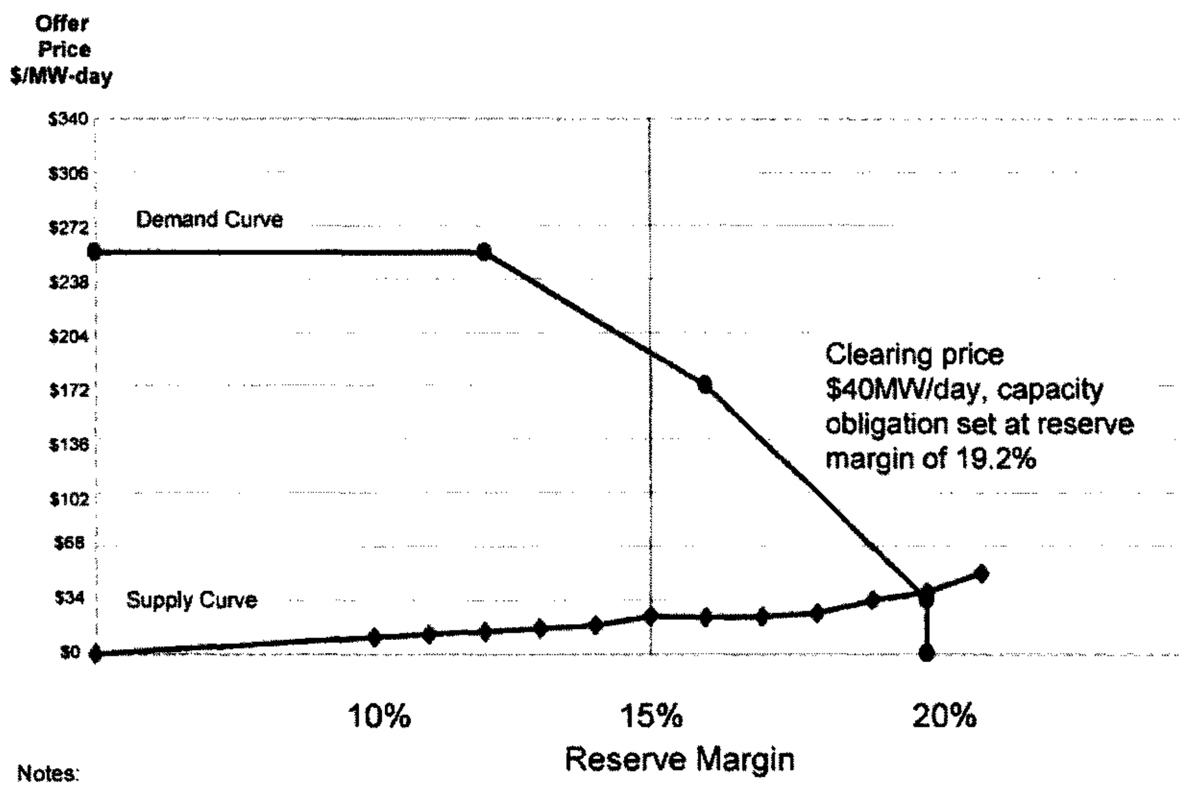
A. There are two methods in PJM for the supply and procurement of capacity – RPM and FRR.

Q. PLEASE BRIEFLY EXPLAIN THE RPM CAPACITY OPTION.

[1] PJM's Reliability Assurance Agreement defines protocols necessary for maintaining reliability on the PJM system.

A. The RPM is an administratively determined market approach. Under the RPM, PJM clears the supply offers from generators against an administrative demand curve to arrive at both a price and a quantity paid by Load Serving Entities (LSEs) for their capacity and reserve obligations. Figure 1 below graphically represents the supply and demand curves for a Base Residual Auction. The Base Residual Auction is what PJM calls the initial auction used to set the RPM clearing prices three years in advance of the delivery year.

Figure 1: Example of Supply/Demand Curve – Entire PJM Region



Notes:
• Demand curve is administratively set by PJM. Maximum clearing price = 1.5 x Net CONE = $25(5)8/MW-day in graph.
• Supply curve is based on offers by generators in RPM capacity market.
• Net CONE is equivalent to $172/MW-day. Net CONE is defined as the cost of new entry for a gas peaking unit. PJM uses this value as the basis for determining the RPM demand curve.

In the graph above, the top line is the administrative demand curve. It is generally a downward sloping curve. This means that the more MWs which are purchased, the lower the price paid per MW of capacity. PJM calls this the Variable Resource Requirement curve.

The upward sloping curve is the supply curve. This curve is developed through actual offers submitted by generators into the RPM auction.

In this graph, the two curves cross where the price equals approximately $40/MW-day and the quantity of capacity procured is approximately at a 19.2% reserve margin. The graph shows that all the loads in this zone will need to purchase capacity equal to a 19.2% reserve margin at $40/MW-day. So, as a simplistic example, an LSE with a 100MW peak load obligation in the 2007/08 delivery year, which is participating in the RPM auction process, will pay $1.7M (100MWs x 1.192 x $40/MW-day x 365 days = $1.7M) to PJM for its capacity obligations in this particular example, which is representative of the 2007/08 delivery year auction.

Q. IS THE $40/MW-DAY THE PRICE PAID BY THE CRES PROVIDER?

A. No. The $40/MW-day in the example is indicative of what the initial RPM auction cleared for the 2007/08 delivery year. As Witness Pearce describes in his testimony (and Exhibit KDP-7), the rate charged to CRES providers must include adjustments to the initial base auction for MWs cleared in the incremental auctions, and then grossed up for PJM's scaling factors (for reserves and load changes) and losses. For 2007/08, the initial clearing price was approximately $40/MW-day, while the final capacity charge to CRES providers was approximately $46/MW-day.

Q. PLEASE EXPLAIN THE FRR OPTION.

A. The FRR was developed to allow a utility the ability to provide its own capacity resources for its load obligations and not be subject to the RPM capacity market fluctuations (i.e. volatile clearing prices and reserve margins). Under the FRR option, the LSE supplies its own capacity obligations through its own generating fleet, or through bi-lateral arrangements with another supplier. If an LSE has a 100MW capacity obligation and chose FRR, the LSE could supply this capacity from its own generation fleet without making any payments to PJM.

Q. WHY WAS THE FRR OPTION DEVELOPED AS ANOTHER METHOD FOR SUPPLYING CAPACITY?

A. It was important to have an appropriate mechanism for LSEs that owned or controlled sufficient generation to meet their own load and reserve margin obligations. AEP advocated strongly at FERC and during the stakeholder negotiations for the FRR option. This option was important to AEP, because:

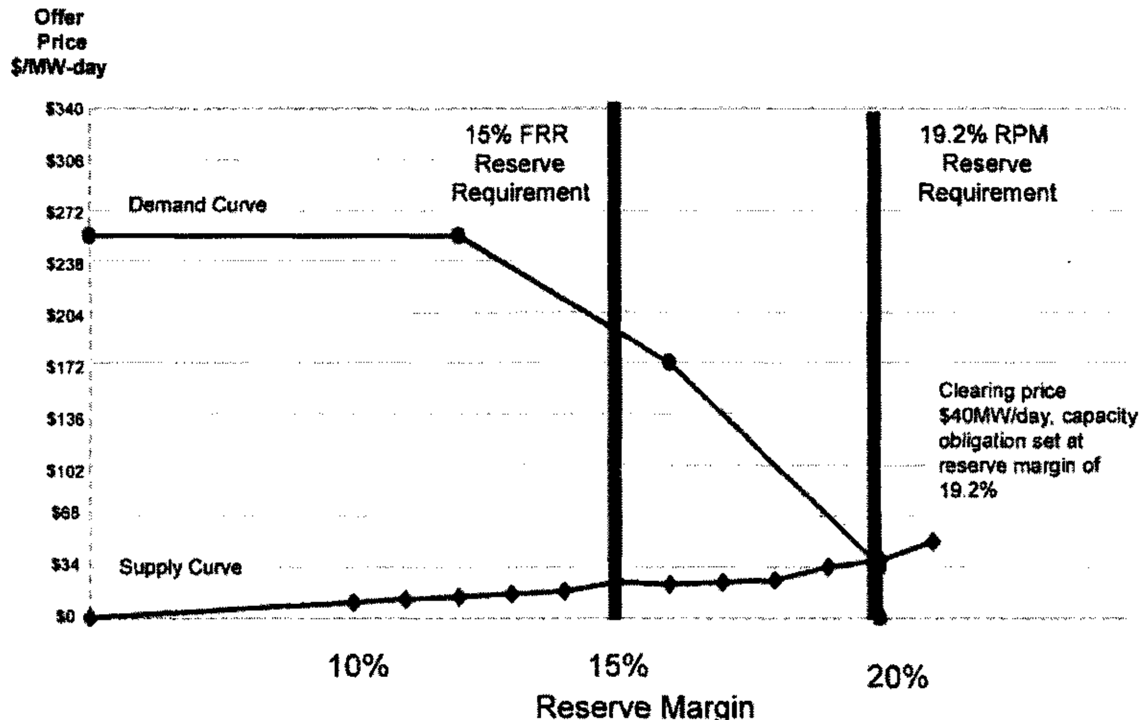
- FRR was consistent with the Company's regulatory framework. AEP utilities in PJM were among the few remaining vertically integrated utilities that retained their generation to meet the load obligations of their customers. For AEP, the FRR mechanism allowed it to continue to recover its embedded generation costs associated with the customers it serves through existing Commission approved rate structures. Conversely, many of the other PJM utilities have segregated their load from their generation, either by divesting their generation to third parties or transferring it to affiliated generation companies.
- It did not make sense for AEP to offer its own generation into a capacity auction and then essentially be required to buy it back to satisfy its load obligation, since the Company had sufficient generation to meet its own load obligation.

- AEP was at risk for being required to purchase more capacity than necessary because of the potential for the RPM auction to clear at a higher reserve margin level than the Company carried on its system.

Q. WHAT WAS THE OUTCOME OF THIS INITIAL DECISION?

A. At the time AEP initially made the decision to choose FRR, the FRR reserve requirement as set by PJM was 15%. In 2007/08, the auction actually cleared at a 19.2% reserve margin. If we had chosen RPM in 2007/08, AEP would have purchased an additional 4.2% of capacity to meet the RPM reserve margin that was not necessary to meet the Company's internal load obligations. See Figure 2 for a graphic representation of this difference.

Figure 2: Comparison of Reserve Requirements FRR vs RPM



Notes:
- Demand curve is administratively set by PJM. Maximum clearing price = 1.5 x Net CONE = $25(5)8/MW-day in graph.
- Supply curve is based on offers by generators in RPM capacity market.
- Net CONE is equivalent to $172/MW-day. Net CONE is defined as the cost of new entry for a gas peaking unit. PJM uses this value as the basis for determining the RPM demand curve.

Q. WHY WAS THE RPM RESERVE MARGIN HIGHER THAN THE FRR RESERVE MARGIN?

A. The key difference is in how the reserve margins are determined for FRR and RPM. For FRR, the reserve margin used is the reserve margin PJM calculates for the entire PJM RTO for planning purposes. However, the reserve margin for RPM is set by supply offers and an administratively set demand curve. Figure 2 above shows this relationship graphically.

Q. WHAT WOULD THIS ADDITIONAL 4.2% IN CAPACITY RESERVES HAVE COST AEP AND ITS CUSTOMERS?

A. In the 2007/08 period, this additional capacity obligation would have cost AEP and its customers an additional $15.7M.

Q. HOW DID YOU DERIVE THIS NUMBER?

A. AEP's total company peak load in PJM is approximately 22,000MWs. If the Company had been required to carry an additional 4.2% in capacity reserves, AEP would have been obligated to supply 925MWs of additional capacity for 2007/08 (4.2% of 22,000MWs). With the billed RPM capacity rate of $46.73/MW-day (which is the $40/MW-day clearing price grossed up for reserve margin and losses), the total cost would have been 925MWs x $46.73/MW-day x 365 days = $15.7M.

Q. PLEASE COMPARE THE RESERVE MARGIN FOR FRR TO THE RESERVE MARGIN FOR RPM FOR ALL THE YEARS THE AUCTION HAS CLEARED TO DATE.

A. There have been eight RPM auctions held since the initiation of the capacity auctions for the 2007/08 delivery year. The average target reserve margin set annually by PJM has been approximately 15.5% from 2007/08 through 2014/15. The average reserve margin cleared in the RPM auction in these eight years has been approximately 19% in the AEP zone. The difference is 3.5%. With the average RPM clearing price for all auctions being approximately $90/MW-day, AEP has saved its customers $25M annually (22,000MWs x 3.5% x $90/MW-day x 365 days = $25M) by choosing FRR.

Q. BACK TO THE INITIAL DEVELOPMENT OF THE FRR OPTION, HOW DID FERC RULE ON FRR IN ITS INITIAL OPINION?

A. FERC agreed that it was not necessary or appropriate to force utilities such as AEP to participate in the RPM auction. In their April 20, 2006 Initial Order, FERC states in paragraph 110 that "We agree with AEP that LSEs and states should have the option of choosing an alternative to the forward procurement auction if they identify sufficient capacity to meet their loads…."

At that point, as part of the settlement process at FERC, PJM and the PJM stakeholders entered into negotiations to develop the FRR process. These deliberations focused on the preparation of rules that enabled utilities such as AEP to meet their capacity obligations through use of their own generation (including bi-lateral arrangements) and to maintain reserve margins established by the PJM planning process rather than through the auction process. This provided benefits to native load customers by giving the LSEs choices for meeting capacity requirements.

Q. WERE YOU PART OF THE FERC SETTLEMENT NEGOTIATIONS RELATING TO THE FRR RULES?

A. Yes. The development of the FRR was largely driven by AEP. The AEP team (including myself) was at the core of and very active in the PJM stakeholder deliberations relating to these issues. These discussions took place under FERC Docket ER05-1410.

Q. PLEASE EXPLAIN HOW A CRES PROVIDER SERVING LOAD IN THE SERVICE TERRITORY OF AN FRR ENTITY MAY SUPPLY ITS CAPACITY REQUIREMENT.

A. The CRES provider has two options for supplying its capacity requirement. These include: 1) supplying its own capacity (with its own generation or through a bi-lateral contract) or 2) paying the FRR entity to supply capacity for the CRES provider.

Q. DURING THE FERC SETTLEMENT PROCESS, DID THE STAKEHOLDERS DISCUSS THE LEVEL OF COMPENSATION FOR CAPACITY TO BE PAID BY CRES PROVIDERS TO FRR ENTITIES?

A. Yes. The stakeholders held several discussions throughout the FERC settlement process regarding the compensation level for capacity that CRES retail LSEs would pay to the FRR entities in the event that the CRES provider did not have sufficient generation resources to enable them to meet their capacity requirements.

Q. WHY WAS IT NECESSARY TO DISCUSS THE CAPACITY COMPENSATION TO BE PAID BY CRES PROVIDERS?

A. Under the FRR rules, AEP is ultimately responsible for ensuring adequate capacity resources to meet the load obligation in its service territory, except for capacity that is self-supplied by a CRES provider. This includes not only the load served by AEP, but also any load that has switched to a CRES provider. To fulfill the total capacity requirement for the AEP service territory, the Company supplies capacity resources to meet the Company's load obligation while the CRES provider has the option of either 1) paying AEP to supply its capacity obligation or 2) providing its own resources to meet its capacity obligation. Therefore, this compensation discussion was necessary to ensure that the FRR entity was adequately compensated for supplying capacity resources used by a CRES provider.

Q. WERE THERE MULTIPLE OPTIONS DISCUSSED FOR CHARGING CRES PROVIDERS FOR THE CAPACITY COVERED UNDER AN FRR PLAN?

A. Yes. The PJM stakeholders ultimately agreed upon three options for determining an adequate capacity reimbursement price for CRES providers. The first approach, which would initially serve as a default mechanism, would be for the charges to track the market clearing price set in the RPM auctions. However, the major drawback was that there was no guarantee the auction prices would reimburse an FRR entity for its embedded cost of capacity. So, the stakeholders agreed upon another method under which the level of capacity compensation would be based on the FRR's embedded capacity costs.

Further, during the PJM stakeholder process, there also was a discussion about the possibility that any state utility commission might seek to implement a retail choice program with rules that require shopping customers to pay capacity-related charges directly to the incumbent utility. Although AEP was not aware of any such retail mechanism in any of the states in which AEP utilities operated, the Company did not oppose the inclusion of a provision that would accommodate the possibility that Ohio or another retail-choice state might one day decide to implement such a capacity charge directly to a retail customer (as opposed to a wholesale charge to a CRES provider). AEP fully expected that any such provision within our regulated jurisdictions would allow the Company to recover the costs for the capacity it is obligated to supply.

Q. HAS THE PUBLIC UTILITY COMMISSION OF OHIO (COMMISSION) VOICED SUPPORT FOR THE FRR PLAN SINCE ITS INCEPTION?

A. Yes. The Commission staff referred to FRR in public comments filed at FERC provided in advance of a FERC Staff Technical Conference on June 7, 2006. In the first sentence of their comments, the Commission staff said they "would like to compliment the FERC for accepting the traditional resource requirement approach (the Fixed Resource Requirement option) as a legitimate alternative to RPM. The Ohio Staff would like to request that, in developing the rules for the two alternatives, the FERC needs to ensure that a resource supplier is treated equitably in terms of the [Installed Reserve Margin (IRM)] requirement, the penalties for violating an IRM requirement, and the appropriate length of a resource commitment, regardless of what alternative the supplier chooses."

Q. DID THE COMMISSION PARTICIPATE IN THE RPM AND FRR NEGOTIATIONS?

A. The Commission staff was present at many of the sessions in Washington D.C. Because of the nature of the settlement negotiations, I am not permitted to disclose any details of positions voiced or taken during the discussions.

Q. YOU HAVE DISCUSSED THE RESERVE MARGIN BENEFITS OF CHOOSING FRR. WERE THERE OTHER BENEFITS THAT RESULTED FROM CHOOSING FRR?

A. Yes. In addition to the reserve margin benefits noted above, the FRR plan allows AEP the flexibility to substitute generating units within its fleet for meeting the Company's FRR capacity obligations in case of significant unit outages. In other words, AEP can utilize generating units that **are not** committed as capacity resources to replace generating units that **are** committed capacity resources in the event of unforeseen operational issues. This flexibility allows AEP the ability to minimize, or possibly eliminate, financial penalties assessed by PJM associated with non-performance of a committed capacity resource.

Q. HAS AEP BENEFITED FROM THIS FLEXIBILILTY?

A. Yes. In 2009, AEP experienced an extended, but unexpected outage with a committed capacity resource that lasted for over a year. Fortunately, under the FRR, AEP was able to substitute other uncommitted capacity resources within the AEP fleet for this unit in order to avoid most of the penalties that PJM would have assessed had AEP been in RPM. The RPM rules do not allow LSEs to hold some units in reserve to cover unexpected forced outages.

Q. IS THERE A FINANCIAL BENEFIT TO THIS FLEXIBILITY?

A. Yes. To illustrate the financial implications of being able to manage the risk of forced outages, if AEP would find itself 1000 MW short of capacity due to an unexpected forced outage, the penalty provisions for the 2009/10 delivery year would be 120% of the RPM clearing price. This would equate to $44M of penalties for a 1000 MW shortage (1000MWs x 365 days x 120% x $102/MW-day RPM clearing price).

Q. WOULD AEP HAVE REALIZED THE SAME BENEFITS IN RPM?

A. No. Under RPM AEP would have to offer 100% of its capacity into the auction and not hold any capacity in reserves to address forced outage situations.

Q. ARE THE CRES PROVIDERS EXPOSED TO THESE PENALTY PROVISIONS IF THEY DO NOT BRING THEIR OWN CAPACITY TO SERVE THEIR RETAIL OBLIGATIONS?

A. No. If a CRES provider relies on AEP for its capacity requirement, AEP is responsible for 100% of the penalties associated with non-performance under the FRR, and does not pass on to the CRES providers any of the penalties incurred.

Q. PLEASE ILLUSTRATE THE IMPACT OF USING THE RPM AUCTION CLEARING PRICE ON THE CAPACITY CHARGE PAID BY CRES PROVIDERS AND THE FRR ENTITY.

A. For 2012/13, the RPM auction clearing price in the AEP zone was approximately $20/MW-day. This is equivalent to a $0.83/MWH adder to the energy cost ($20/MW-day/24 hours). The average PJM wholesale energy costs in 2010 were

$48.34/MWH. The $0.83/MWH for capacity is only 1.7% of the energy price using these illustrative numbers.

However, if the RPM capacity auction clearing price continues to rise to Net CONE, the clearing price will be closer to $342/MW-day (the Net CONE used for the 2014/15 auction, as represented in Figure 3 below). This would equate to a $14.25/MWH ($342/MW-day / 24 hours) cost for capacity. This $14.25/MWH for capacity is over 29% of the 2010 energy cost of $48.34/MWH.

etter@occ.state.oh.us,
grady@occ.state.oh.us,
small@occ.state.oh.us,
cynthia.a.fonner@constellation.com,
David.fein@constellation.com,
Dorothy.corbett@duke-energy.com,
Amy.spiller@duke-energy.com,
dboehm@bkllawfirm.com,
mkurtz@bkllawfirm.com,
ricks@ohanet.org,
tobrien@bricker.com,
jbentine@cwslaw.com,
myurick@cwslaw.com,
zkravitz@cwslaw.com,
jejadwin@aep.com,
msmalz@ohiopovertylaw.org,
jmaskovyak@ohiopovertylaw.org,
todonnell@bricker.com,
cmontgomery@bricker.com,
lmcalister@bricker.com,
mwarnock@bricker.com,
gthomas@gtpowergroup.com,
wmassey@cov.com,
henryeckhart@aol.com,
laurac@chappelleconsulting.net,
whitt@whitt-sturtevant.com,
thompson@whitt-sturtevant.com,
sandy.grace@exeloncorp.com,
cmiller@szd.com,
ahaque@szd.com,
gdunn@szd.com,
mhpetricoff@vorys.com,
smhoward@vorys.com,
mjsettineri@vorys.com,
lkalepsclark@vorys.com,
bakahn@vorys.com,
Gary.A.Jeffries@dom.com,
Stephen.chriss@wal-mart.com,
dmeyer@kmklaw.com,
holly@raysmithlaw.com,
barthroyer@aol.com,
philip.sineneng@thompsonhine.com,
carolyn.flahive@thompsonhine.com,
terrance.mebane@thompsonhine.com,
cmooney2 @columbus.rr.com,
drinebolt@ohiopartners.org,

nolan@theoec.org,
gpoulos@enernoc.com,
emma.hand@snrdenton.com,
doug.bonner@snrdenton.com,
clinton.vince@snrdenton.com,
sam@mwncmh.com,
joliker@mwncmh.com,
fdarr@mwncmh.com,
jestes@skadden.com,
paul.wight@skadden.com,
dstahl@eimerstahl.com,
aaragona@eimerstahl.com,
ssolberg@eimerstahl.com,
tsantarelli@elpc.org,
callwein@wamenergylaw.com,
malina@wexlerwalker.com,
jkooper@hess.com,
kguerry@hess.com,
afreifeld@viridityenergy.com,
swolfe@viridityenergy.com,
korenergy@insight.rr.com,
sasloan@aep.com,
Dane.Stinson@baileycavalieri.com
Jeanne.Kingery@duke-energy.com

AEP 122

P.U.C.O. NO. 20

Rider DLC
(Experimental Direct Load Control Rider)

Availability of Service

Available to individual residential customers on a voluntary, experimental basis for residential electric service. Availability is restricted to customers served by the circuits designated for the Company's gridSMART^{SM} program. Customers taking service under Schedule CPP are not eligible for this rider. This rider will be in effect for a minimum of one (1) year.

For non-owner occupied dwellings, the Company may require permission from the owner to install auxiliary communicating equipment, smart thermostat device, or load control switch. Customers will not be eligible for this rider if the owner does not allow installation of the equipment.

The customer may chose to participate in the electric cooling unit program only. Customers participating in the electric cooling unit program may also choose to participate in the electric water heating unit control, electric pool pump or electric hot tub programs.

Service under this rider is limited based upon the availability of smart thermostat devices and load control switch devices. The Company plans to have approximately 8,500 smart thermostat devices in total to distribute in the gridSMART^{SM} area for all programs. The Company plans to have a total of 1,000 load control switches available for the electric water heating unit, pool pump, or hot tub program. At the Company's option, this rider may be made available to additional customers. Upon request by the Company and approval by the Commission in a future filing, additional customers may be responsible for the Commission-approved cost of the smart thermostat device and load control switch.

Program Description

To participate, customers must allow the Company, or its authorized agents, to install a smart thermostat device, load control switch(es) and, if necessary, auxiliary communicating devices to control the customer's central electric cooling unit(s) and / or electric water heater unit(s), pool pump(s), or hot tub(s). All such devices shall be installed at a time that is consistent with the orderly and efficient deployment of this program.

The Company will utilize the smart thermostat device and the load control switch(es) to reduce customer's energy use during load management events. The smart thermostat device may employ either a temperature setback or cycling methodology.

Under a temperature setback methodology, the Company may increase the preset temperature on the customer's thermostat by no more than four (4) degrees during load management events.

Under a cycling methodology, the Company may cycle off the central electric cooling unit(s) generally for up to one-half of every hour of a load management event.

The load control device will switch off the electric water heating unit, pool pump, and/or hot tub during a load management event.

P.U.C.O. NO. 20

Rider DLC
(Experimental Direct Load Control Rider)

Company planned load management events shall not exceed five (5) hours per day. Such non-emergency load management events shall not exceed 15 events and shall occur only during the months of May through September between Noon and 8 pm.

Electric water heating units and hot tubs would be subject to 15 additional non-emergency load management events during the months of October through April between 5 am and 11 pm.

For emergency purposes, load management events shall not exceed 10 events per PJM planning year (June through May) and not last longer than six (6) hours duration. Emergencies shall be determined by PJM as defined in PJM Manual 13 – Emergency Operations. Emergency load management events can only occur between Noon and 8 pm on weekdays during May through September and 2 pm to 10 pm on weekdays during October through April.

Rate Credit

Electric Cooling Unit (Summer Only)

Customers taking service under Schedules R-R, RLM, RS-ES, RS-TOD, and RS-TOD2 shall receive the following monthly billing credits in June through October for each electric cooling unit controlled during the calendar months of May through September:

$ 8.00 for any calendar month where the customer does not override an event signal
$ 4.00 for any calendar month where the customer overrides one (1) event signal
$ 0.00 for any calendar month where the customer overrides more than one (1) event signal

Customers taking service under Schedule R-R-1 shall receive the following monthly billing credits in June through October for each electric cooling unit controlled during the calendar months of May through September:

$ 3.00 for any calendar month where the customer does not override an event signal
$ 1.50 for any calendar month where the customer overrides one (1) event signal
$ 0.00 for any calendar month where the customer overrides more than one (1) event signal

Pool Pump (Summer Only)

Residential customers shall receive a $6.00 billing credit per month in June through October for each pool pump controlled during the calendar months of May through September.

P.U.C.O. NO. 20

Rider DLC
(Experimental Direct Load Control Rider)

Electric Water Heating Unit and Hot Tub (Year-Round)

Residential customers shall receive the following monthly billing credits for each electric water heating unit or hot tub controlled:

Electric Water Heating Unit	$ 1.00 per calendar month
Hot Tub	$ 2.00 per calendar month

Such credits shall not reduce the customer's bill below the minimum charge as specified in the schedule under which the customer takes service.

Equipment

The Company will furnish and install, in the customer's presence, a smart thermostat device, load control switch(es) and, if necessary, an auxiliary communicating device inside the customer's residence. All equipment will be owned and maintained by the Company until such time as the experimental direct load control program is discontinued or the customer requests to be removed from the program after completing the initial mandatory period of one (1) cooling season (May through September) for electric cooling units and pool pumps or one (1) year for electric water heating units and hot tubs. At that time, ownership of the smart thermostat will transfer to the customer and the auxiliary communicating device will be picked up or returned to the Company at the Company's expense in good working order. The customer is not required to pay a deposit for this equipment; however, failure to return the auxiliary communicating device in good working order may result in additional charges in the amount of the current prevailing cost of the auxiliary equipment.

Should the customer lose or damage the smart thermostat device, load control switch(es) or auxiliary communicating equipment, the customer will be responsible for the cost of repairing or replacing the device(s). If the device(s) malfunctions through no fault of the customer, the Company will replace or repair the device(s) at its expense.

Contract

Electric Cooling Unit and Pool Pump

Participating customers must agree to participate for an initial period of one (1) cooling season (May through September) and thereafter may discontinue participation by contacting the Company.

Electric Water Heating Unit and Hot Tub

Participating customers must agree to participate for an initial period of one (1) year and thereafter may discontinue participation by contacting the Company.

Rider DLC
(Experimental Direct Load Control Rider)

Special Terms and Conditions

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the schedule under which the Customer takes service, including all payment provisions.

The Company shall not be required to install load management equipment if the installation cannot be justified for reasons such as: technological limitations, safety concerns, or abnormal utilization of equipment, including vacation or other limited occupancy residences.

The Company and its authorized agents shall be permitted access to the customer's premises during normal business hours to install, inspect, test, or maintain the load management device(s). The Company shall also be allowed access to the customer's premise to repair or remove faulty load management device(s).

The Company shall collect data during the course of this experiment. Customer-specific information will be held as confidential and data presented in any analysis will protect the identity of the individual customer.

FES X 119

Information release: Dropping delinquent customers
ohiochoiceoperation
to:

05/14/2012 03:21 PM
Sent by:
smsemran@aep.com
Hide Details
From: ohiochoiceoperation@aep.com

To:

Sent by: smsemran@aep.com

History: This message has been forwarded.

1 Attachment

CRES message dropping delinquent csts May 2012.doc

AEP Ohio Choice Operations
OhioChoiceOperation@AEP.com
614-883-6990
614-883-6991

AEP Ohio on May 16 will begin reassigning Choice customers back to the company's Standard Offer Service (SOS) if they have a 60-day delinquency of more than $50. AEP Ohio will continue to remit any payments received from these customers to their selected provider for 80 days after the drop has taken place. After 80 days it will be the responsibility of the CRES Provider to collect any additional past due charges. Customers will not be allowed to select another CRES provider until past due amounts are paid.

FAQ's:

- What will the transaction EDI code be for this drop?

  AEP Ohio would send the CRES Provider an EDI 814 drop transaction, along with an EDI 248 write-off transaction when AEP Ohio will no longer attempt to collect payment on behalf of the CRES provider (which is 80 days after the customer is dropped).

- Will customers be notified of the reason they are being dropped?

  Yes, customers will receive a letter informing them of the reason they are being returned to AEP's SOS. The letter will state the following:

Customer Name
Customer Address
City State Zip

Date

Dear (Customer Name):

AEP Ohio would like to make you aware of a change to your electric service account.

Your account has been returned to AEP Ohio's Standard Offer Service due to unpaid past due charges for longer than 60 days. As a result, AEP Ohio will begin providing your electricity service according to the applicable Standard Offer service tariff rate.

You will be required to remain on AEP Ohio's Standard Offer Service and not eligible to switch to another Provider until your arrearage has been paid.

Please call our Customer Choice Solutions Center at 1-888-237-5566 if you have any questions.

Sincerely,
AEP Ohio

- Will customers be charged a switch fee from being dropped?

AEP Ohio will not charge customers a fee for being dropped due to non-pay. If a customer pays his arrearages and chooses to switch back to a CRES Provider, a customer will be allowed to do so. A switch fee might apply at that time.

Any payment received from the customer within 80 days of the customer being dropped will be sent to the Provider.

If you have questions, we are willing to arrange a conference call to discuss this with you.

Exhibit A
NFIB 105

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
REVENUES			
Electric Generation, Transmission and Distribution	$ 4,406,814	$ 4,222,461	$ 3,875,595
Sales to AEP Affiliates	977,999	991,285	921,089
Other Revenues – Affiliated	27,903	21,069	23,457
Other Revenues – Nonaffiliated	18,395	20,301	15,592
TOTAL REVENUES	5,431,111	5,255,116	4,835,733
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	1,597,410	1,488,474	1,286,718
Purchased Electricity for Resale	300,653	286,835	263,385
Purchased Electricity from AEP Affiliates	515,613	386,618	288,115
Other Operation	754,109	795,129	675,785
Maintenance	393,943	346,745	350,880
Asset Impairments and Other Related Charges	89,824	–	–
Depreciation and Amortization	545,376	513,168	496,470
Taxes Other Than Income Taxes	399,479	393,537	369,461
TOTAL EXPENSES	4,596,407	4,210,506	3,730,814
OPERATING INCOME	834,704	1,044,610	1,104,919
Other Income (Expense):			
Interest Income	7,069	2,567	2,238
Carrying Costs Income	53,345	31,796	18,354
Allowance for Equity Funds Used During Construction	5,549	5,949	6,094
Interest Expense	(221,977)	(242,000)	(241,134)
INCOME BEFORE INCOME TAX EXPENSE	678,690	842,922	890,471
Income Tax Expense	213,697	301,306	310,195
NET INCOME	464,993	541,616	580,276
Net Income Attributable to Noncontrolling Interest	–	–	2,042
NET INCOME ATTRIBUTABLE TO OPCo SHAREHOLDERS	464,993	541,616	578,234
Preferred Stock Dividend Requirements Including Capital Stock Expense	1,259	881	889
EARNINGS ATTRIBUTABLE TO OPCo COMMON SHAREHOLDER	$ 463,734	$ 540,735	$ 577,345

The common stock of OPCo is wholly–owned by AEP.

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
NET INCOME	$ 464,993	$ 541,616	$ 580,276
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $1,477 in 2011, $529 in 2010 and $3,365 in 2009	(2,743)	(981)	6,249
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $5,894 in 2011, $5,128 in 2010 and $4,614 in 2009	10,946	9,522	8,568
Pension and OPEB Funded Status, Net of Tax of $13,876 in 2011, $10,901 in 2010 and $870 in 2009	(25,770)	(20,245)	1,615
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(17,567)	(11,704)	16,432
TOTAL COMPREHENSIVE INCOME	447,426	529,912	596,708
Total Comprehensive Income Attributable to Noncontrolling Interest	-	-	2,042
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO OPCo SHAREHOLDERS	$ 447,426	$ 529,912	$ 594,666

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	OPCo Common Shareholder					
	Common Stock	Paid–in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2008	$ 321,201	$ 1,158,172	$ 2,372,720	$ (184,883)	$ 16,799	$ 3,684,009
Capital Contribution from Parent		550,000				550,000
Common Stock Dividends – Affiliated			(245,000)			(245,000)
Common Stock Dividends – Nonaffiliated					(2,042)	(2,042)
Preferred Stock Dividends			(732)			(732)
Purchase of JMG		36,509			(17,910)	18,599
Capital Stock Expense		157	(157)			–
Noncash Dividend of Property to Parent			(8,123)			(8,123)
Other Changes in Equity					1,111	1,111
SUBTOTAL – EQUITY						3,997,822
NET INCOME			578,234		2,042	580,276
OTHER COMPREHENSIVE INCOME				16,432		16,432
TOTAL EQUITY – DECEMBER 31, 2009	321,201	1,744,838	2,696,942	(168,451)	–	4,594,530
Common Stock Dividends			(469,075)			(469,075)
Preferred Stock Dividends			(732)			(732)
Gain on Reacquired Preferred Stock		4				4
Capital Stock Expense		149	(149)			–
SUBTOTAL – EQUITY						4,124,727
NET INCOME			541,616			541,616
OTHER COMPREHENSIVE LOSS				(11,704)		(11,704)
TOTAL EQUITY – DECEMBER 31, 2010	321,201	1,744,991	2,768,602	(180,155)	–	4,654,639
Common Stock Dividends			(650,000)			(650,000)
Preferred Stock Dividends			(671)			(671)
Loss on Reacquired Preferred Stock		(1,216)				(1,216)
Capital Stock Expense		324	(324)			–
SUBTOTAL – EQUITY						4,002,752
NET INCOME			464,993			464,993
OTHER COMPREHENSIVE LOSS				(17,567)		(17,567)
TOTAL EQUITY – DECEMBER 31, 2011	$ 321,201	$ 1,744,099	$ 2,582,600	$ (197,722)	$ –	$ 4,450,178

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in thousands)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,095	$ 949
Advances to Affiliates	219,458	154,702
Accounts Receivable:		
Customers	146,432	136,373
Affiliated Companies	162,830	252,851
Accrued Unbilled Revenues	19,012	60,749
Miscellaneous	16,994	15,042
Allowance for Uncollectible Accounts	(3,563)	(3,768)
Total Accounts Receivable	341,705	461,247
Fuel	262,886	330,171
Materials and Supplies	201,325	204,700
Risk Management Assets	54,293	54,547
Accrued Tax Benefits	11,975	77,818
Prepayments and Other Current Assets	41,560	77,884
TOTAL CURRENT ASSETS	1,135,297	1,362,018
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	9,502,614	9,576,404
Transmission	1,948,329	1,896,989
Distribution	3,545,574	3,422,413
Other Property, Plant and Equipment	546,642	562,847
Construction Work in Progress	354,465	325,903
Total Property, Plant and Equipment	15,897,624	15,784,556
Accumulated Depreciation and Amortization	5,742,561	5,533,889
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,155,063	10,250,667
OTHER NONCURRENT ASSETS		
Regulatory Assets	1,370,504	1,232,122
Long-term Risk Management Assets	53,614	50,101
Deferred Charges and Other Noncurrent Assets	309,775	342,127
TOTAL OTHER NONCURRENT ASSETS	1,733,893	1,624,350
TOTAL ASSETS	$ 13,024,253	$ 13,237,035

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
December 31, 2011 and 2010

	2011	2010
	(in thousands)	
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 293,730	$ 269,165
Affiliated Companies	183,898	202,050
Long-term Debt Due Within One Year – Nonaffiliated	244,500	165,000
Risk Management Liabilities	36,561	38,133
Customer Deposits	55,785	57,669
Accrued Taxes	450,570	455,825
Accrued Interest	66,441	67,017
Other Current Liabilities	182,490	210,555
TOTAL CURRENT LIABILITIES	1,513,975	1,465,414
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,609,648	3,803,352
Long-term Debt – Affiliated	200,000	200,000
Long-term Risk Management Liabilities	17,890	14,626
Deferred Income Taxes	2,245,380	2,136,467
Regulatory Liabilities and Deferred Investment Tax Credits	301,124	290,291
Employee Benefits and Pension Obligations	335,029	383,160
Deferred Credits and Other Noncurrent Liabilities	351,029	272,470
TOTAL NONCURRENT LIABILITIES	7,060,100	7,100,366
TOTAL LIABILITIES	8,574,075	8,565,780
Cumulative Preferred Stock Not Subject to Mandatory Redemption	–	16,616
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321,201	321,201
Paid-in Capital	1,744,099	1,744,991
Retained Earnings	2,582,600	2,768,602
Accumulated Other Comprehensive Income (Loss)	(197,722)	(180,155)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,450,178	4,654,639
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 13,024,253	$ 13,237,035

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OHIO POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in thousands)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 464,993	$ 541,616	$ 580,276
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	545,376	513,168	496,470
Deferred Income Taxes	119,184	292,831	514,201
Asset Impairments and Other Related Charges	89,824	–	–
Carrying Costs Income	(53,345)	(31,796)	(18,354)
Allowance for Equity Funds Used During Construction	(5,549)	(5,949)	(6,094)
Mark–to–Market of Risk Management Contracts	(3,695)	25,251	(10,271)
Pension Contributions to Qualified Plan Trust	(127,884)	(58,639)	–
Property Taxes	(5,722)	(19,324)	(14,474)
Fuel Over/Under–Recovery, Net	(727)	(131,850)	(333,598)
Change in Other Noncurrent Assets	(73,242)	3,797	(31,547)
Change in Other Noncurrent Liabilities	85,173	(17,079)	50,986
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	116,197	(126,071)	32,482
Fuel, Materials and Supplies	79,787	66,700	(198,124)
Accounts Payable	(17,059)	72,694	(189,103)
Accrued Taxes, Net	36,466	131,441	(136,746)
Other Current Assets	7,789	924	16,955
Other Current Liabilities	(15,821)	53,985	(34,048)
Net Cash Flows from Operating Activities	1,241,745	1,311,699	719,011
INVESTING ACTIVITIES			
Construction Expenditures	(454,873)	(504,702)	(716,543)
Change in Advances to Affiliates, Net	(64,756)	283,650	(438,352)
Acquisitions of Assets	(2,229)	(5,801)	(1,429)
Proceeds from Sales of Assets	47,463	14,382	35,706
Other Investing Activities	29,014	26,400	21,680
Net Cash Flows Used for Investing Activities	(445,381)	(186,071)	(1,098,938)
FINANCING ACTIVITIES			
Capital Contribution from Parent	–	–	550,000
Issuance of Long–term Debt – Nonaffiliated	49,748	351,824	584,936
Change in Advances from Affiliates, Net	–	(24,202)	(184,550)
Retirement of Long–term Debt – Nonaffiliated	(165,000)	(868,580)	(295,500)
Retirement of Long–term Debt – Affiliated	–	(100,000)	–
Retirement of Cumulative Preferred Stock	(17,831)	(7)	(1)
Principal Payments for Capital Lease Obligations	(11,854)	(11,617)	(6,976)
Dividends Paid on Common Stock – Nonaffiliated	–	–	(2,042)
Dividends Paid on Common Stock – Affiliated	(650,000)	(469,075)	(245,000)
Dividends Paid on Cumulative Preferred Stock	(671)	(732)	(732)
Acquisition of JMG Noncontrolling Interest	–	–	(28,221)
Other Financing Activities	390	(5,370)	(2,649)
Net Cash Flows from (Used for) Financing Activities	(795,218)	(1,127,759)	369,265
Net Increase (Decrease) in Cash and Cash Equivalents	1,146	(2,131)	(10,662)
Cash and Cash Equivalents at Beginning of Period	949	3,080	13,742
Cash and Cash Equivalents at End of Period	$ 2,095	$ 949	$ 3,080
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 226,711	$ 239,984	$ 241,627
Net Cash Paid (Received) for Income Taxes	81,740	(78,268)	(15,759)
Noncash Acquisitions Under Capital Leases	5,766	33,369	3,275
Government Grants Included in Accounts Receivable at December 31,	1,383	9,260	–
Construction Expenditures Included in Current Liabilities at December 31,	61,428	31,939	61,035
Noncash Dividend of Property to Parent	–	–	8,123

See Notes to Financial Statements of Registrant Subsidiaries beginning on page 225.

OCC 109

**OHIO POWER COMPANY'S RESPONSES
TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
NINTH SET**

INTERROGATORY

OCC-INT-9-174 Identify all persons who have submitted documents to the PUCO, including correspondence, that have been docketed in this proceeding since January 2012, with whom You have had communications regarding the ESP filing, AEP's corporate commitment to communities and organizations in Ohio, the content of any documents submitted in this case, or other issues in this matter. For each such Person:

a. Identify the person and state a contact address and phone number for such person;

b. State the date(s) on which You had communications with such Person;

c. Identify who initiated the communication on behalf of the Companies;

d. Provide a summary of the content of your communications with such person; and

e. Identify all documents sent between You and such person(s).

RESPONSE

a-e:
The Company objects to this request as being vague, overbroad, and unduly burdensome. Without waiving the foregoing objection(s) or any general objection the Company may have, the information referenced below was located after a good faith search based on the Company's understanding of the question. See OCC-INT-9-174 Attachments 1 through 6 for what the Company believes to be the requested information.

Prepared by: Counsel

OHIO POWER COMPANY'S RESPONSES
TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
NINTH SET

REQUEST FOR PRODUCTION OF DOCUMENTS

OCC-RPD-9-062 Please produce all documents sent between you and any person who has testified at any of the four local public hearings held in 2012 in connection with this case regarding the ESP filing, AEP's corporate commitment to Ohio, the content of any documents, including testimony or presentations offered or to be offered at any local public hearing, or other issues in this matter.

RESPONSE

See the Company's response to OCC-INT-9-174.

Prepared by: Counsel

**OHIO POWER COMPANY'S RESPONSES
TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
NINTH SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

OCC-RPD-9-063 Please produce all documents sent between you and any person who has submitted documents to the PUCO since January 1, 2012, including correspondence, that have been docketed in this proceeding regarding the ESP filing, AEP's corporate commitment to Ohio, the content of any documents docketed in this proceeding, or other issues in this matter.

RESPONSE

See the Company's response to OCC-INT-9-174.

Prepared by: Counsel

**OHIO POWER COMPANY'S RESPONSES
TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
NINTH SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

OCC-INT-9-064 Please produce all documents sent between you and any person who has had communications with the Commission since January 1, 2012 regarding the ESP filing, AEP's corporate commitment to the communities in Ohio, the content of any communications, or other issues in this matter.

RESPONSE

See the Company's response to OCC-INT-9-174.

Prepared by: Counsel

Name	Address	Phone	Date	Cont Initiated By	Comment Summary
Brenda Linnick	215 South Walnut Street, Wooster Ohio 45615	330-264-5576	25-Apr-12	Wheeler	ESP Support Letter
Jedd Metzger	144 South Main Street, Lima, Ohio 45801	419-222-6045	3-May-12	Payne	ESP Support Letter
Kurt Reiber	1141 Central Parkway, Cincinnati, Ohio 45202	513-482-4500	30-Apr-12	Buck	ESP Support Letter
United Appeal Athens County	469 Richland Aveneue, Athens 45701	740-592-1293	25-Apr-12	Buck	ESP Support Letter
United Way of Tuscarawas County	1458 5th Street NW, New Phila, Ohio 44663	330-343-7772	25-Apr-12	Wheeler	ESP Support Letter
EODA	PO box 904 326 Highland Ave, Cambridge, Ohio 43725	(740)432-7902	25-Apr-12	Wheeler	ESP Support Letter

OCC-INT-174
Attachment 1

LETTERS

Name	Address	Phone	Date	Cont Initiated By	Content Summary
Robbb Hankins	900 Cleveland Ave NW, Canton Ohio 44701	330-453-1075	25-Apr-12	Wheeler	Support for ESP filing
Chad Conrad	1451 Fourth Street, New Philoa Ohio 44663	330-343-8633	25-Apr-12	Wheeler	Support for ESP filing
Amy Rutledge	61 North Lisbon Street, Carrollton, Ohio 44615	330-627-5500	25-Apr-12	Wheeler	Support for ESP filing
Terrance Jones	424 Fulton Road NW, Canton Ohio 44207	(330)471-9139	25-Apr-12	Wheeler	Support for ESP filing
Gary Little	330 University Dr., NE, New Phila Ohio 44663	330-308-7524	25-Apr-12	Wheeler	Support for ESP filing

OCC-INT-174
Attachment 2 - Canton

None

Name	Address	Phone	Date	Cont Initiated By	Summary of Content
Milt Baughman	Greater Columbus Arts Council, 100 E Broad St # 2250 Columbus, OH 43215	(614) 224-2606	4/25/2012	Dale Heydlauff, AEP	ESP Filing
Todd Dieffenderfer	United Way of Central Ohio, 360 South 3rd Street, Columbus, OH 43215	(614) 227-2700	4/24/2012	Teresa McWain, AEP	ESP Filing
Don Chenoweth	*Andrews House, 39 West Winter Street, Delaware, OH 43015*	(740) 369-4520	4/25/2012	*Tim Wells, AEP Ohio*	ESP Filing
David Chesebrough	COSI Columbus, 333 West Broad Street Columbus, OH 43215	(614) 228-2674	4/24/2012	Pablo Vegas, AEP Ohio	ESP Filing
Ed Cohn	Big Brothers Big Sisters, 1855 East Dublin Granville Road Columbus, OH 43229	(614) 839-2447	4/24/2012	Teresa McWain, AEP	ESP Filing
Mike Cosgrove	Habitat for Humanity, 3140 Westerville Road, Columbus, Ohio 43224	(614) 414-0427	4/24/2012	Dale Heydlauff, AEP	ESP Filing
Elfi DiBella	YWCA Columbus, 65 South Fourth Street, Columbus, OH 43215	(614) 224-9121	4/24/2012	Dale Heydlauff, AEP	ESP Filing
Alex Fischer	Columbus Partnership, 150 South Front Street, Suite 200, Columbus, Ohio 43215	(614) 225-0500	4/24/2012	Dale Heydlauff, AEP	ESP Filing
Chuck Gehring	LifeCare Alliance, 1699 West Mound Street Columbus, OH 43223	(614) 278-3130	4/25/2012	Dale Heydlauff, AEP	ESP Filing
Matthew Kelly	Columbus State Community College, 550 East Spring St., Columbus, OH 43215	(614) 287-2437	4/24/2012	Dale Heydlauff, AEP	ESP Filing
Michelle Heritage	Community Shelter Board, 111 Liberty Street, Columbus, OH 43215	(614) 221-9195	4/24/2012	Teresa McWain, AEP	ESP Filing
Laurie Marsh	Leadership Columbus, 150 S Front St # 200, Columbus, OH 43215	(614) 225-6948	4/24/2012	Dale Heydlauff, AEP	ESP Filing
Amy Taylor	Columbus Downtown Development Corporation, 150 S. Front Street, Suite 210 Columbus, OH 43215	(614) 545-4700	4/24/2012	Dale Heydlauff, AEP	ESP Filing
Marilyn Tomasi	Mid-Ohio Foodbank, 3960 Brookham Drive Grove City, OH 43123	(614) 274-7770	4/24/2012	Nick Akins, AEP	ESP Filing
Becky Westerfelt	Huckleberry House, 1421 Hamlet Street Columbus, OH 43201	(614) 294-5553	4/24/2012	Teresa McWain, AEP	ESP Filing
Representative	Franklin University, 201 South Grant Avenue Columbus, OH 43215	(614) 797-4700	4/24/2012	Teresa McWain, AEP	ESP Filing
Cheri Mitchell	Ballet Met, 322 Mt. Vernon Avenue, Columbus, Ohio 43215	(614) 229-4860	4/24/2012	Teresa McWain, AEP	ESP Filing

Name	Address	Phone	Date	Cont Initiated By	Summary of Content
Sam Bassitt	301 N. Main Street, Lima, Ohio 45802	419-423-8506	5/3/2012	Payne	Support for ESP Hearing
Marcel Wagner	144 S. Main Street, Lima, Ohio 45802	419-222-7706	5/3/2012	Payne	Support for ESP Hearing
Bambi Markham	1380 E. Kibby Street, Lima, Ohio 45802	419-222-7946	5/3/2012	Payne	Support for ESP Hearing

OCC-INT-174
Attachment 2 - Lima

AEP OHIO
unit of American Electric Power

AEP Ohio's Modified Electric Security Plan (ESP)

Plan balances rate impact to all customers while continuing to foster competition

We heard the concerns of our customers
and developed a plan that mitigates the significant rate increases that affected certain customers while providing moderate adjustments for all customers.

- During the first year, all AEP Ohio customers will see an average increase of 5 percent and a 9 percent overall increase over the life of the plan.
- The increases are associated with distribution investments made since the company's last distribution base rate cases nearly 20 years ago and deep discounts we are providing to competitive suppliers (discussed below).

This plan helps facilitate moving Ohio into a fully competitive environment
by providing third-party suppliers deeply discounted prices from our proven costs for use of our generation facilities. To offer deals to Ohio customers, these suppliers need to use our capacity because they either do not have their own generation investment or chose not to commit their own generation resources. Our generation capacity is contractually obligated to Ohio customers until May 31, 2015.

- AEP Ohio's current cost-based capacity charge, as presented in a case currently before the PUCO, is approximately $355/MW day. AEP is offering a fixed discounted capacity rate to our competitors of $146/MW day for the first 21 percent (2012), 31 percent (2013), and 41 percent (2015) of each customer class, and $255/MW day for the remaining customers.
- The company also set aside discounted capacity to serve the expected non-mercantile load of the communities that passed aggregation initiative in the November 2011 election.
- The discounted prices proposed in the plan at both levels are known to allow suppliers to make competitive offers to customers.
- Some parties will advocate for deeper discounts on capacity. Doing so would further subsidize competitors, represent unfair competition, and harm AEP and its investors.
- Some parties will advocate that the plan hinders a customer's ability to save. It doesn't come down to a customer's savings; it comes down to a supplier's profit. Competitors want to use AEP Ohio's power plants to serve customers while paying AEP Ohio next to nothing and keeping a majority of the profit.

In order to create robust competition in Ohio, the state needs more than one strong competitor.
AEP Ohio's plan creates the ability to do this by giving the company time to transition to a fully competitive business model and being fairly compensated by suppliers for assets currently dedicated to its customers.

- All businesses require fair play and fair dealing. AEP supports a three-year transition plan in order to corporately separate its generation assets. In contrast, First Energy asked for a two-phase, five year transition and did not corporately separate until 2008.
- AEP Ohio is proposing a "Retail Stability Rider" that will provide the customer stable and predictable rates while providing the company financial stability through the transition period. In contrast, FE argued they needed significant assistance to offset the costs associated with a transition to competitive market and received nearly $7 billion in stranded costs from customers through 2010.

OCC-INT-174
Attachment 3

Date:

Public Utilities Commission of Ohio
180 East Broad Street
Columbus, Ohio 43215
Attn: Chairman Snitchler

Dear Chairman Snitchler,

Please allow me to add my support to the growing number of communities, organizations and individuals speaking out in favor of the AEP Ohio modified Electric Security Plan (ESP).

It is my understanding that AEP Ohio's plan does not restrict the ability of customers to shop for a retail electricity supplier, either through community aggregation or directly with a competitive retail electric supply (CRES) provider. The capability to shop has existed long before AEP Ohio introduced its ESP and is supported by the plan. If the goal is to establish a truly competitive marketplace, AEP Ohio will need to be able to fully compete, which is best guaranteed through a predictable and orderly transition to market.

AEP Ohio has been a strong community partner and works to help provide job growth and business retention in our community, both vital in assuring the health and vibrancy of each community they serve.

The company's recent ESP is a compromise that provides clarity and direction for the company and its customers, while providing much needed certainty around critical public policy. Overall, it is a plan that enhances retail shopping, promotes economic development, asset investment and an orderly transition to fully market-based generation rates.

Thank you for adding these sentiments to Docket No. 11-346-EL-SSO.

Sincerely,

Name
Organization
Address

OCC-INT-174
Attachment 4

Draft Press Release - Wapakoneta Area Economic Development Council

April XX, 2012 – Wapakoneta, Ohio. For Immediate Release

AEP Commits Millions to Readiness of West Central Ohio Industrial Site

The Wapakoneta Area Economic Development Council announced today a multimillion-dollar commitment by American Electric Power (AEP) in power infrastructure and supply at the West Central Ohio Industrial Center job ready site in Wapakoneta, OH. This investment will enable 40-plus megawatt supply to the 471-acre industrial job ready site. The exact amount of the intended investment was not disclosed.

AEP executives said they committed to this investment because they recognize the quality and potential of the West Central Ohio Industrial Center.

"This site in Wapakoneta has got to be one of the premier industrial job ready sites in the United States. We want to be part of this tremendous opportunity for business development in Ohio, " said XXX, yyyy at AEP.

"We are extremely grateful that AEP has chosen to support our site. AEP's new commitment is a critical investment in our site's readiness," said Greg Myers, Director of the Wapakoneta Area Economic Development Council.

The West Central Ohio Industrial Center began development in 2006. It lies in the heart of an industrial and transportation corridor boasting major freeway access and an onsite CSX rail spur. The site was one of the first three industrial sites certified under the State of Ohio's Job Ready Site program in October, 2010. It received elite "CSX Select Site" status from CSX Rail in February 2012.

"We have turned over every stone in preparing this site for new industrial installations, " said Myers. "It is truly beyond anyone's description of job ready. All a buyer needs to do is come to Wapakoneta and turn shovels."

Mark Kvamme, President and Interim Chief Investment Officer for JobsOhio, praised AEP's commitment to the West Central Ohio Industrial Center.

"This is huge for Ohio. Investments such as these into job ready sites are invaluable to the state's economic future," said Kvamme. "Logistics costs are increasingly more expensive for businesses and Ohio is an ideal location for any company looking to offset those costs."

#

Name	Address	Phone	Date	Cont Initiated By	
Robbb Hankins	900 Cleveland Ave NW, Canton Ohio 44701	330-453-1075	25-Apr-12	Wheeler	Support for ESP filing
Chad Conrad	1451 Fourth Street, New Philoa Ohio 44663	330-343-8633	25-Apr-12	Wheeler	Support for ESP filing
Amy Rutledge	61 North Lisbon Street, Carrollton, Ohio 44615	330-627-5500	25-Apr-12	Wheeler	Support for ESP filing
Terrance Jones	424 Fulton Road NW, Canton Ohio 44207	(330)471-9139	25-Apr-12	Wheeler	Support for ESP filing
Gary Little	330 University Dr., NE, New Phila Ohio 44663	330-308-7524	25-Apr-12	Wheeler	Support for ESP filing
Sam Bassitt	301 N. Main Street, Lima, Ohio 45802	419-423-8506	5/3/2012	Payne	Support for ESP Hearing
Marcel Wagner	144 S. Main Street, Lima, Ohio 45802	419-222-7706	5/3/2012	Payne	Support for ESP Hearing
Bambi Markham	1380 E. Kibby Street, Lima, Ohio 45802	419-222-7946	5/3/2012	Payne	Support for ESP Hearing
Brenda Linnick	215 South Walnut Street, Wooster Ohio 45615	330-264-5576	25-Apr-12	Wheeler	ESP Support Letter
Jedd Metzger	144 South Main Street, Lima, Ohio 45801	419-222-6045	3-May-12	Payne	ESP Support Letter
Kurt Reiber	1141 Central Parkway, Cincinnati, Ohio 45202	513-482-4500	30-Apr-12	Buck	ESP Support Letter
United Appeal Athens County	469 Richland Aveneue, Athens 45701	740-592-1293	25-Apr-12	Buck	ESP Support Letter
United Way of Tuscarawas County	1458 5th Street NW, New Phila, Ohio 44663	330-343-7772	25-Apr-12	Wheeler	ESP Support Letter
EODA	PO box 904 326 Highland Ave, Cambridge, Ohio 43725	(740)432-7902	25-Apr-12	Wheeler	ESP Support Letter

OCC-INT-174
Attachment 6

PUCO CONTACTS

IEU 120

**OHIO POWER COMPANY'S RESPONSES,
TO THE OFFICE OF THEOHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
SUPPLEMENTAL FIFTH SET**

INTERROGATORY

OCC-INT-5-092 Please provide a copy of all documents pertaining to the testing of the OPCO generation assets for recoverability in accordance with Accounting Standard Codification 360, as referred to in response to OCC INT 1-012. Please include the results of the tests which indicated that the undiscounted cash flows exceeded the carrying value and impairment was not applicable.

RESPONSE

The various documents supporting the OPCo generation asset impairment testing in accordance with ASC 360 referred to in OCC INT 1-12 are provided in Attachments 1 – 13. The confidential level of the documents are currently being reviewed and Counsel for OCC has been notified. In the interest of not delaying the other responses the documents will be provided once labeled and parties wanting copies, besides OCC, should contact the Company and request the documents

Prepared by: T.E. Mitchell

SUPPLEMENTAL RESPONSE

The various documents supporting the OPCo generation asset impairment testing in accordance with ASC 360 referred to in OCC INT 1-12 are provided in Attachments 1 - 13 and are summarized as follows. The Company objects that some of the documents are highly confidential and sensitive that rise to the level of being restricted access documents. Notwithstanding, and without waiving the objection, the Company will make the documents available for review in the Company offices for review only upon request and execution of an appropriate protective agreement.

Attachment 1: Memo documenting test and conclusions.

Restricted Access Confidental Attachment 2: 2011 Preliminary Long Range Forecast (Referenced on page 3 of the Memo).

OCC-INT-5-092 (Continued)

Restricted Access Confidental Attachment 3: Forecast assumptions used (Referenced on page 3 of the Memo).

Attachment 4: Current average depreciable life of units (Referenced on page 3 of the Memo).

Attachments 5 - 9: June 30, 2011 Income Statements by Company (Referenced on page 3 of the Memo).

Restricted Access Confidental Attachments 10 - 13: CSPAR rules and impact of cash flows (Referenced on page 4 of the Memo).

Prepared by: Counsel/T.E. Mitchell