BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan.	)))))	Case No. 13-2385-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	)))	Case No. 13-2386-EL-AAM

APPLICATION FOR REHEARING OF OHIO POWER COMPANY

Pursuant to Section 4903.10, Ohio Revised Code ("R.C."), and Rule 4901-1-35, Ohio Administrative Code ("O.A.C."), Ohio Power Company ("AEP Ohio" or the "Company") respectfully files this Application for Rehearing of the Commission's February 25, 2015 Opinion and Order ("Opinion and Order"). The Commission's Opinion and Order is unreasonable and unlawful in the following respects:

I. It was unreasonable for the Commission to defer to another proceeding its consideration of including OVEC in the PPA Rider when the record in this case already supports rate stability benefits of the OVEC asset.

II. The Commission's modifications to the Distribution Investment Rider (DIR) component of the ESP are unreasonable and should be changed or clarified on rehearing.

    A. The Commission should reconsider its decision to reduce the Company-proposed DIR revenue caps and its denial of the Company's proposal to include general plant within the DIR.

        1. The Company's proposed annual revenue caps should be adopted on rehearing.

        2. The targeted proposal for inclusion of certain general plant should be permitted on rehearing.

B. Alternatively, the Commission should correct the mistaken DIR revenue caps listed on Page 47 of the Opinion and Order so that they properly reflect the Commission's stated intention to set the annual revenue caps "based on the level of growth of three to four percent as permitted for the DIR in the ESP 2 Case." Opinion and Order at 47.

C. It would also partially offset the adverse effects of drastic annual revenue cap reductions to clarify in this context that the Commission's intention in the *ESP II* decision was to adopt an $86 million annual revenue cap for 2012 without proration, which would produce a significant carryover amount that would also help alleviate the problem for 2015 and beyond.

D. Due to the immediate and substantial impact on the Company's capital commitments and investment in Ohio, the Company asks that the Commission issue an expedited rehearing decision on these DIR issues, to the extent it does not issue a full rehearing order within the normal 30-day timeline required by R.C. 4903.13.

III. The Opinion and Order's treatment of Rider IRP-D is unreasonable and unlawful in several respects and should be clarified or corrected.

A. The Commission should clarify on rehearing that its Opinion and Order did not intend to eliminate the provisions of the existing IRP-D tariff that: (a) require customers to contract for not less than 1 megawatt (MW) of interruptible capacity; (b) cap the total interruptible power contract capacity for all customers served under Rider IRP-D at 525 MW. If it did intend to eliminate those provisions, the Opinion and Order is unreasonable and unlawful.

B. The Commission should modify the method through which AEP Ohio recovers its actual costs of providing the IRP-D interruptible credits from the EE/PDR Rider to the Economic Development Rider (EDR). Reliance on the EE/PDR Rider as a cost-recovery mechanism will create an unreasonable and unlawful burden for customers paying the costs of the credits provided to Rider IRP-D customers. Moreover, recovery of those costs through the EDR is consistent with the substantial economic development purpose of the EDR.

C. The Commission must modify its directive that AEP Ohio bid capacity resources associated with Rider IRP-D into PJM's capacity auctions and then offset against the cost of the IRP-D credits the revenues received from PJM, because the directive is infeasible and, thus, unreasonable and unlawful. Instead, the Commission should modify Rider IRP-D so that it can achieve the result that the Commission seeks.

D. The Commission should also confirm that AEP Ohio is entitled to fully recover its costs of providing all interruptible credits required by Rider IRP-D; if the Opinion and Order did intend to create uncertainty regarding the Company's right to recover those costs, it is unreasonable and unlawful and should be corrected on rehearing.

IV. The Commission's modification and authorization of the Purchase of Receivables Program and Associated Bad Debt Rider is unreasonable and unlawful.

A. It is unreasonable for the Commission to leave so many merit issues involved in the litigation open for further debate subject to a future proceeding.

B. It is unreasonable for the Commission to include a CRES providers early termination fees as a commodity-related charge.

C. It is unreasonable and unlawful for the Commission to allow a CRES provider to pick and choose its customers that the regulated utility will be required to acquire their receivables.

D. It is unreasonable and unlawful for the Commission to modify the AEP proposed POR structure to provide CRES providers on consolidated billing the yearly option to participate.

E. It is unreasonable and unlawful for the Commission to forego creation of a mechanism for cost recovery of the implementation and administrative costs of the modified program.

F. It is unreasonable for the Commission to require plans for supplier consolidated billing and switching provisions in the August 31, 2015 implementation filing.

G. It is unreasonable and unlawful for the Commission to set up a bad debt rider to recover generation related costs above the amount already being recovered through base rates, because the record does not contain the amount in base rates related to CRES Receivables and generation-related uncollectible expense.

H. It is unreasonable for the Commission to order AEP to implement a Commission modified POR program that will not allow it to disconnect for non-payment of expenses the regulated utility is required to purchase.

I. It is unreasonable that the Commission creates a greater liability on the utility by denying the right to disconnect for receivables but does not provide an industry-wide applied practice of a late payment fee to encourage timely payment.

V. The Commission's denial of AEP Ohio's proposed NERC Compliance and Cybersecurity Rider was unreasonable and unlawful.

VI. On rehearing, the Commission should correct the Opinion and Order's determination regarding the MRO Test by finding that the modified ESP provides $53,060,000 of quantifiable benefits that would not be possible under an MRO.

As noted in Section II.D above, the Company asks that the Commission issue an expedited rehearing decision on these DIR issues, to the extent it does not issue a full rehearing order within the normal 30-day timeline required by R.C. 4903.13, due to the immediate and substantial impact on the Company's capital commitments and investment in Ohio. A memorandum in support of this Application for Rehearing is attached.

Respectfully submitted,

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On behalf of Ohio Power Company

MEMORANDUM IN SUPPORT

SUMMARY OF ARGUMENT

The Commission Opinion and Order approved AEP Ohio's Electric Security Plan (ESP III) with modifications set forth in the written decision; any aspects of the Company's proposed ESP that were not addressed are categorically approved and any modification advocated by an intervenor not explicitly adopted in the Opinion and Order is deemed rejected. Opinion and Order at 95. Generally speaking, the Company commends the Commission on its significant legal and policy support for the Purchased Power Agreement (PPA) Rider and other components of the ESP that were adopted through the Opinion and Order. But the Commission should reconsider its decision to defer the question of whether OVEC costs should be included in the PPA Rider. And it is equally important that the significant issues raised in this Application for Rehearing be modified or clarified on rehearing, so the Company can fully understand the modified ESP (and resulting financial impact) and and make an informed choice in deciding whether to exercise its statutory right to reject the modified ESP.

PPA Rider: deferral of decision to permit inclusion of OVEC

The Opinion and Order appropriately concludes that the PPA Rider is supported by the ESP statute, R.C. 4928.143, and the statutory energy policies in R.C. 4928.02. Opinion and Order at 19-23. But then the Commission concludes that, based on the record in this proceeding, it is not persuaded that the OVEC proposal "would provide customers with sufficient benefit from the rider's financial hedging mechanism or any other benefit that is commensurate with the rider's potential cost." *Id*. at 25. While the Commission's decision was based on the record in this case and left the "door open" for AEP Ohio to pursue cost recovery of OVEC in a separate proceeding, AEP Ohio submits that the current record does adequately support approval of the OVEC proposal at this time and requests that the Commission should reconsider its decision to defer ruling on whether to include the OVEC asset in the PPA Rider. The four findings in the Opinion and Order upon which the Commission ultimately concluded that it was "not persuaded" on the current record to include OVEC in the PPA Rider at this time should be re-examined.

First, regarding whether the hedge benefit of including OVEC offsets the potential short-term cost, it cannot be disputed that the PPA Rider will promote rate stability, especially over the long term. Virtually all of the witnesses that testified regarding the PPA Rider acknowledged that PJM market rates are volatile. Indeed, the Commission itself forcefully concluded that "there is no question that the PPA rider would produce a credit or charge based on the difference between wholesale market prices and OVEC's costs, offsetting, to some extent, the volatility in the wholesale market." Opinion and Order at 21.

Second, the Commission was mistaken in concluding that AEP Ohio did make a long-term commitment beyond the ESP term to ensure that the projected long-term financial benefits of the OVEC proposal would accrue to the benefit of customers. Mr. Vegas was clear in binding AEP Ohio to a long-term commitment regarding the PPA Rider and, in particular, keeping the OVEC asset for the benefit of customers. The Company would have no objection if that is incorporated as a condition on rehearing to inclusion of the OVEC costs in the PPA Rider.

Third, AEP Ohio submits that it is unreasonable for the Commission to defer approval of PPA Rider costs until resolution of uncertainty relating to PJM market reforms, environmental regulations and federal litigation. All of these areas could take considerable time and may well end up causing wholesale market prices to increase, which would mean that it would be too late for the PPA Rider to be taken up at that point. A clear and decisive ruling on the PPA Rider, which involves important and urgent issues of Ohio energy policy, is presently needed by this Commission.

The fourth reason the Commission gave for deferring a ruling on OVEC is that some stability exists now due to SSO auction strategies of laddering and staggering as well as fixed rate offerings of CRES providers. The evidence of record showed, however, that even with the SSO auction design tools of laddering and staggering, the auction clearing prices still follow market price changes up and down. It would be misguided to conclude that an additional tool for rate mitigation should be categorically excluded, especially given the flaws and limitations of the existing mitigation tools.

Distribution Investment Rider (DIR)

In its *ESP II* Opinion and Order, the Commission found that "adoption of the DIR and the improved service that will come with the replacement of aging infrastructure will facilitate improved service reliability and better align the Company's and its customers' expectations." *In re Application of Columbus Southern Power Company and Ohio Power Company*, Case Nos. 11-346-EL-SSO et al. (*ESP II*), Opinion and Order at 46 (Aug. 8, 2012) ("*ESP II* Opinion and Order"). The Company's proposal to include the DIR as part of *ESP III* was intended to continue reliability-impacting infrastructure investment and better align the Company's and customers' interests. The Opinion and Order, however, significantly reduced the Company's proposal and adopted DIR revenue caps as follows:

	2015	2016	2017	2018	TOTAL
Application	$156 M	$192M	$200M	$103M	$671M
Opinion & Order	$124M	$146.2M	$170M	$103M	$543.2M
Reduction	$ 32M	$ 45.8M	$ 30M	$0	$127.8M

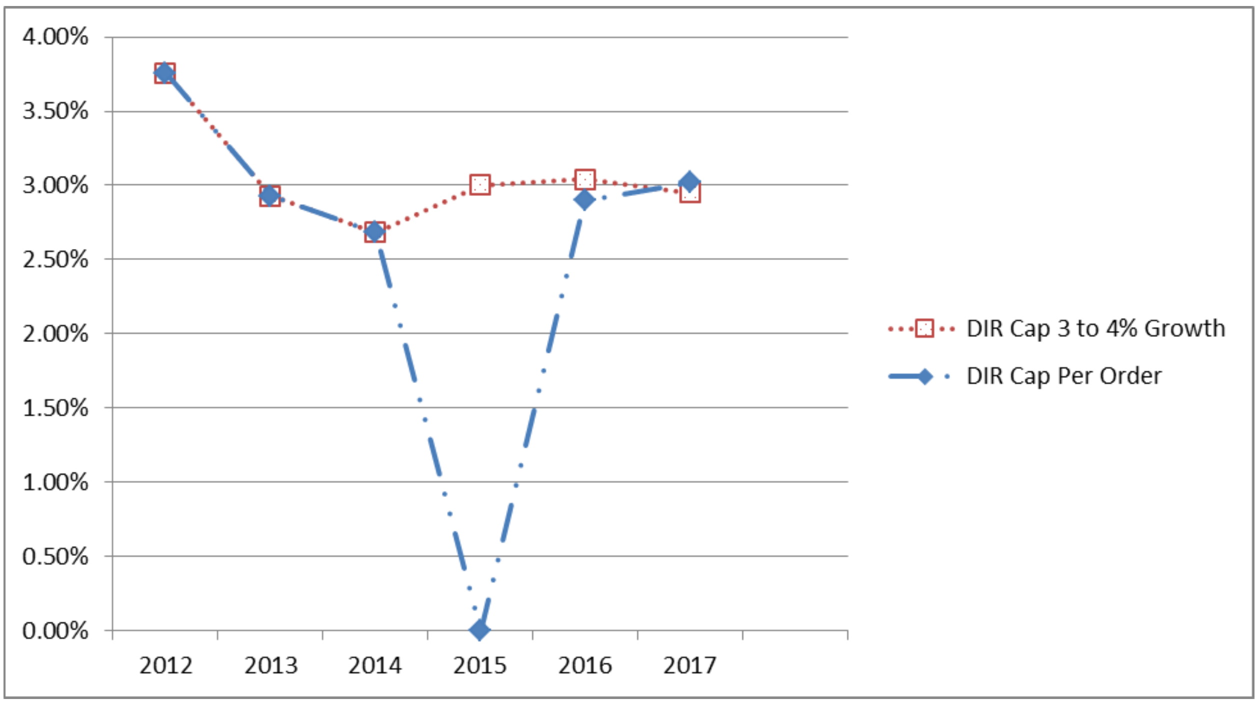
These annual revenue cap reductions and the impact on the Company's capital spend are extremely problematic for the Company and put the programs already under way this year at significant risk. The annual revenue cap reductions significantly impair the Company's ability to continue to make reliability-impacting distribution investments.

Accordingly, the Company requests that the Commission adopt one or more of the following options to better align the Company's and customers' reliability expectations and interests: (A) reinstate the Company's proposed annual revenue caps; (B) adjust the apparent mistake in the stated DIR revenue caps listed on Page 47 of the Opinion and Order so that they properly match the Commission's stated intention to set the annual revenue caps based on the level of growth of three to four percent; (C) clarify that the Commission's intention in the *ESP II* decision was to adopt an $86 million annual revenue cap for 2012 without proration, which would increase the carryover amount that would apply to 2015 and beyond; and/or (D) due to the immediate and substantial impact on the Company's capital commitments and investment in Ohio, the Company asks that the Commission issue an expedited rehearing decision on these DIR issues, to the extent it does not issue a full rehearing order within the normal 30-day timeline required by R.C. 4903.13.

Of all the modifications made to the DIR, the most problematic feature of the DIR adopted in the Opinion and Order is the reduced DIR annual revenue caps and, in particular, the directive to keep the 2015 revenue cap at 2014 levels with zero growth. In reducing the

Company's proposed annual revenue caps, the Commission stated that it "determined the annual DIR amounts based on the level of growth of three to four percent as permitted for the DIR in the *ESP 2 Case*." Opinion and Order at 47. However, the numbers reflected in the Order do not match this explanation. In reality, the adopted annual DIR revenue caps result in <u>0% growth</u> in distribution revenue for 2015, followed by a more reasonable 2.8% growth in 2016 and 3% growth in 2017.

When comparing the growth rate of the *ESP II* DIR caps to the *ESP III* adopted caps, it is clear that the *ESP III* adopted caps are not consistent with the Commission's stated intention:



Given that the revenue caps listed in the Opinion and Order do not match three separate descriptions of the Commission's intent regarding the DIR (discussed below), the revenue caps appear to have been incorrectly listed on Page 47 of the Opinion and Order and could easily be corrected on rehearing.

The DIR annual revenue caps can only support new investment if they continue to grow each year. Generally, for example, approximately every $20 million increase in the annual DIR revenue caps will support $100 million of new capital investment above normal depreciation levels. By contrast, if the annual revenue cap is flat and incorporates no increase, investment at depreciation levels is all that is supported. Using the Company's current depreciation level of 3.68%, this means that a flat DIR revenue cap for 2015 would only support $146 million of capital spend, which would take the Company back to a pre-DIR spending level and would result in a reduction in the experienced crews that perform this work. These are the same crews that help to provide a rapid response to storm related outages. If left uncorrected, the decision will make it difficult for the Company to staff construction projects in subsequent years because those crews will be off of our property and committed elsewhere. Those would be setbacks that the Commission could not have intended here.

And such results clearly do not match the Commission's explicitly-stated intention of extending *ESP II*'s 3-4% annual growth trend and do not fit with the Commission's separately-stated expectation of approving a funding "level to allow AEP Ohio to continue to replace aging infrastructure in order to maintain and improve service reliability over the term of this ESP." Opinion and Order at 47. The reduced DIR caps also undermine the Commission's additional expectation that "although AEP Ohio has not committed to refrain from filing a distribution rate case application during the ESP period, the Commission's approval of the continuation of the DIR, ESRR, and other distribution-related riders should enable the Company to hold base distribution rates constant over the ESP period, while making significant investments in distribution infrastructure and improving service reliability." *Id.* at 95. The DIR caps should be amended on rehearing to match up with the Commission's stated intentions. Due to the immediate and substantial impact on the Company's capital commitments and investment in Ohio, the Company asks that the Commission issue an expedited rehearing decision on these

DIR issues, to the extent it does not issue a full rehearing order within the normal 30-day timeline required by R.C. 4903.13.

<u>Interruptible Service (Rider IRP-D)</u>

In this proceeding, the Company initially proposed to eliminate its interruptible tariff, IRP-D, because the benefits of interruptible service relate, for the most part, to the provision of generation service. As a wires-only company, AEP Ohio believed it might not be best able to provide an interruptible service product. (AEP Ohio Ex. 13, at 9.) In its post-hearing briefs, AEP Ohio indicated that it would not oppose retaining a modified version of Rider IRP-D – subject to important qualifications. The Commission found that Rider IRP-D should be retained, but modified, to "provide for unlimited emergency interruptions[,] and that the $8.21/kW-month credit should be available to new and existing shopping and non-shopping customers." Opinion and Order at 40. The approved Rider IRP-D would provide eligible customers a credit of $8.21/kW-month, which equates to $274/MW-day (a price that substantially exceeds the capacity charge approved by the Commission for AEP Ohio's former generation plants). *Id.* The Commission also allowed that "[c]onsistent with its current practice, AEP Ohio should continue to apply for recovery of the costs associated with the IRP-D through the EE/PDR rider, until otherwise ordered by the Commission." *Id.* The Commission further directed "AEP Ohio [to] bid the additional capacity resources associated with the IRP-D into PJM's base residual auctions held during the ESP term, with any resulting revenues credited back to customers through the EE/PDR rider." *Id.* AEP Ohio has four concerns regarding the Commission's findings and directives regarding Rider IRP-D and the recovery of the costs of its $8.21/kW-month credit.

First, the Commission should clarify on rehearing that its Opinion and Order did not intend to eliminate the provisions of the existing IRP-D tariff that: (a) require customers to contract for not less than 1 megawatt (MW) of interruptible capacity; and (b) cap the total interruptible power contract capacity for all customers served under Rider IRP-D at 525 MW. If it did intend to eliminate those provisions, the Opinion and Order is unreasonable and unlawful. Second, the Commission should modify the method through which AEP Ohio recovers its actual costs of providing the IRP-D interruptible credits from the EE/PDR Rider to the Economic Development Rider (EDR). Reliance on the EE/PDR Rider as a cost-recovery mechanism will create an unreasonable and unlawful burden for customers paying the costs of the credits provided to Rider IRP-D customers. Moreover, recovery of those costs through the EDR is consistent with the substantial economic development purpose of the EDR. Third, the Commission must modify its directive that AEP Ohio bid capacity resources associated with Rider IRP-D into PJM's capacity auctions and then offset against the cost of the IRP-D credits the revenues received from PJM, because the directive is infeasible and, thus, unreasonable and unlawful. Instead, the Commission should modify Rider IRP-D so that it can achieve the result that the Commission seeks. Fourth, the Commission should also confirm that AEP Ohio is entitled to fully recover its costs of providing all interruptible credits required by Rider IRP-D; if the Opinion and Order did intend to create uncertainty regarding the Company's right to recover those costs, it is unreasonable and unlawful and should be corrected on rehearing.

Purchase of Receivables (POR)

The Company offered to consider a Purchase of Receivables (POR) program to assist with the development of the competitive market. The Company's proposal involved a very specific POR program tied to recovery of bad debt through a Bad Debt Rider. The Company proposal was consistent with other POR offerings that encouraged growth in the number of competitive suppliers in the state (as included in the Staff report in the Market Investigation discussed in this record). The recovery of unpaid CRES receivables in the Bad Debt Rider ensured a no-harm approach to the Company for adopting the POR. Utilization of the baseline determined in the most recent rate case assured that customers would pay no more or no less than the actual bad debt incurred by the Company because the Company proposed to offset all bad debt against that number that included all components of rates to ensure an apples to apples comparison.

The Commission's modification to the POR program left the Company with more questions than answers and should be resurrected as proposed by the Company. Competitive supplier issues are popular issues with a lot of voices and arguments supporting the continued vitality of the competitive market and suppliers. The POR structure offered voluntarily by the Company provided the parameters under which the Company was able to implement the program. The change to a discount rate is a departure from the now successful experience in the Duke territory recognized by the Commission Staff as a significant driver in the expansion of the competitive market. The Commission modification also left unanswered questions on administrative cost recovery, eligibility, increased costs due to the non-mandatory nature, as well as the unknown issues that could result from a working group dominated by competitive suppliers. The modification to improperly offset the bad debt level established in the most recent case by tracking only the generation charges should also be corrected along with a clarification that the Company be authorized to disconnect non-paying customers to avoid greater bad debt.

Finally, the Commission should clarify that any application of the POR program authorized by the Commission in this ESP should not result in any unrecovered costs for the

Company. The implementation of a POR program is intended to provide a convenience for customers and support competitive suppliers in the market. Any and all application should ensure no harm to the utility implementing the program for the benefit of others. Anything short of full recovery of any utility costs would result in an inappropriate subsidy to the competitive retail electric suppliers benefiting from the program.

NERC Compliance and Cybersecurity Rider (NCCR)

In its Opinion and Order, the Commission denied AEP Ohio's proposed NERC Compliance and Cybersecurity Rider (NCCR). Opinion and Order at 62. Although it confirmed that it "believes that NERC compliance and cybersecurity matters are of the utmost importance for Ohio's customers and customer information, as well as for the security of the electric grid and electric distribution utility facilities," and recognized that "it is important that AEP Ohio take the necessary action to secure the electric grid and react <u>quickly</u> to protect the electric distribution system for the benefit of all consumers and the economic stability of our state," the Commission nonetheless declined to establish the requested placeholder rider. *Id.* (emphasis added). The Commission should provide the Company with a recovery mechanism that reflects the critical importance of investments in NERC compliance and cybersecurity matters that this Commission acknowledged. That decision was unreasonable and should be reversed on rehearing.

Market Rate Offer Test (MRO Test)

The Commission made two modifications to the Company's proposed ESP that together add an additional $9 million of costs to the Company and quantitative benefits for customers. First, the Commission noted that the annual $1 million funding of the Neighbor-to-Neighbor program, which was an additional component of the original RDCR mechanism, is an essential element of that credit mechanism that furthers state policy. Opinion and Order at 65. Second, the Commission directed the Company to continue the Ohio Growth Fund by contributing to it $2 million dollars per year over the term of the modified ESP. *Id.* at 69-70. Clarification of these MRO test impacts will help improve the defensibility of the Commission's decision on appeal.

ARGUMENT

I. It was unreasonable for the Commission to defer to another proceeding its consideration of including OVEC in the PPA Rider when the record in this case already supports rate stability benefits of the OVEC asset.

The Opinion and Order appropriately concludes that the PPA Rider is supported by the ESP statute, R.C. 4928.143, and the statutory energy policies in R.C. 4928.02. Opinion and Order at 19-23. But then the Commission concludes that, based on the record in this proceeding, it is not persuaded that the OVEC proposal "would provide customers with sufficient benefit from the rider's financial hedging mechanism or any other benefit that is commensurate with the rider's potential cost." *Id*. at 25. The Commission did go on to make clear that a properly-structured PPA Rider proposal "has the potential to supplement the benefits derived from the staggering and laddering of the SSO auctions, and to protect customer from price volatility in the wholesale market" and that the denial of OVEC's inclusion in the PPA Rider based on the current record does not prevent AEP Ohio from addressing those issues and the other factors listed on Page 25 of the Opinion and Order in a separate proceeding. *Id*. AEP Ohio submits, however, that the current record does adequately support approval of the OVEC proposal at this time and requests that the Commission should reconsider its decision to defer ruling on whether to include the OVEC in the PPA Rider.

There were four related findings in the Opinion and Order upon which the Commission ultimately concluded that it was "not persuaded" on the current record to include OVEC in the

PPA Rider at this time: (1) there was evidence suggesting that inclusion of OVEC "may result in a net cost to customers, with little offsetting benefit from the rider's intended purpose as a hedge against market volatility"; (2) the evidence showing a likelihood of long-term net credit associated with OVEC cannot be relied upon because "the Company has made no offer to ensure that customers receive the alleged long-term benefits of the PPA rider or even a commitment or any type of proposal to continue the rider in subsequent ESP proceedings"; (3) the Commission does not believe it is appropriate at this time to adopt the OVEC proposal because "[t]here is considerable uncertainty with respect to pending PJM market reform proposals, environmental regulations, and federal litigation"; and (4) "there are already existing means, such as the laddering and staggering of SSO auction products and the availability of fixed price contracts in the market, that provide a significant hedge against price volatility." Opinion and Order at 24. The Company disagrees with each of these four underlying findings and asks that the Commission revisit them on rehearing in light of the record in this case.

First, regarding whether the hedge benefit of including OVEC offsets the potential short-term cost, it cannot be disputed that the PPA Rider will promote rate stability, especially over the long term. Virtually all of the witnesses that testified regarding the PPA Rider acknowledged that PJM market rates are volatile.[1] Company witness Vegas explained that the proposed PPA Rider enables AEP Ohio's customers to benefit from the OVEC contract by having a financial hedge that would move in the opposite direction of market prices and provide a financial stabilizing component to customer rates. (Tr. I at 28.) Intervenor witnesses that addressed the PPA Rider also acknowledged the hedge value of the proposal. (*See, e.g.*, Tr. X at 2495 (OCC witness Wilson acknowledged that the PPA Rider would be more valuable to customers as a

[1] In addition to AEP Ohio witnesses Vegas and Allen, Staff witness Dr. Choueiki testified that market prices have been "quite volatile." (Staff Ex. 18 at 10.) OCC witness Wilson also agreed that recent market prices were volatile. (Tr. X at 2490.)

hedge during periods of high market prices, such as a period of extreme weather); Tr. XI at 2558 (OEG witness Taylor agreed that the PPA Rider is a price-stabilizing hedge); *see also* Tr. VII at 1518-19 (Exelon witness Campbell agreed that a financial hedge can provide rate stability, though he opposes the PPA Rider).) OEG witness Alan S. Taylor testified that he expects the PPA Rider to have a stabilizing effect on rates because OVEC costs are largely fixed and stable, given that the underlying coal-fired generation plants involve very capital-intensive technology of a fixed nature. (Tr. XI at 2451-52.) OCC witness Wilson also agreed that a hedge can provide rate stability for retail customers. (Tr. X at 2491.)

Indeed, the Commission itself forcefully concluded that "there is no question that the PPA rider would produce a credit or charge based on the difference between wholesale market prices and OVEC's costs, offsetting, to some extent, the volatility in the wholesale market." Opinion and Order at 21. The Commission also found that "[a]t its core, the PPA rider is expected to move in the opposite direction of wholesale market prices, causing a rate stabilization effect." *Id*. These findings were the basis for concluding that the third criterion of R.C. 4928.143(B)(2)(d) are satisfied by the PPA Rider. Further, the Commission recognized that a PPA Rider proposal may provide for "a significant financial hedge that truly stabilizes rates, particularly during periods of extreme weather." *Id.* at 25. Thus, it was inconsistent with the record and its own findings to conclude (on page 26) that including OVEC in the PPA Rider does not offer a hedge benefit that offsets the potential short-term cost over the ESP term. The benefit of a hedge is not a guaranteed price reduction but stabilization of otherwise volatile prices. The OVEC hedge is a positive and meaningful step – albeit a small and low-risk one – toward that goal.

Second, the Commission was mistaken in concluding that AEP Ohio did make a long-term commitment beyond the ESP term to ensure that the projected long-term financial benefits of the OVEC proposal would accrue to the benefit of customers. OEG witness Taylor raised a concern similar to the Commission's in his testimony and recommended that "AEP Ohio's customers should be assured of the longer-term net benefits of the rider by locking it in" through 2024. (OEG Ex. 3, at 5.) When asked by OEG counsel about the prospect of an obligation longer than the three-year ESP term in connection with the PPA Rider, AEP Ohio witness Vegas readily agreed that the long-term commitment dovetails into the Company's proposal quite well:

> Our intention in establishing the PPA mechanism is to have a long-term contractual relationship with our customers where they get the opportunity to get the benefit of that long-term hedge over an extended period of time.

(Tr. I at 121.) Similarly, when discussing the PPA Rider with OMA counsel, Mr. Vegas also confirmed the Company's intention to enter into a long-term commitment to retail customers:

> This OVEC rider is a concept that is intended to extend beyond this ESP, so we see the benefits of it in the long term so we would want to remain committed to that, to that arrangement.

(Tr. I at 264.) Thus, Mr. Vegas was clear in binding AEP Ohio to a long-term commitment regarding the PPA Rider and, in particular, keeping the OVEC asset for the benefit of customers. The Company would have no objection if that is incorporated as a condition on rehearing to inclusion of OVEC in the PPA Rider.

This situation is similar to the Commission's approval of AEP Ohio's decision to enter into a 20-year renewable energy purchase agreement in *ESP II*, where the Commission approved as prudent the Company's decision to enter into the Timber Road renewable energy purchase agreement (REPA); the costs recovered through retail rates are still subject to ongoing financial audits but not subsequent prudence audits.[2] Of course, OVEC is a legacy contract and the Commission has historically permitted recovery of OVEC costs as being prudent, there is no need to review the prudence of entering into the OVEC contract or the terms and conditions of the OVEC contract.[3]

Accordingly, the Company requests that the Commission reiterate and confirm in its *ESP III* order that it was prudent for the Company to enter into the OVEC contract, and that the Commission will incorporate that prudence determination for the full term of that contract (through 2040). For now, the Commission is being asked to effectively perpetuate the *status quo* and approve the PPA Rider for recovery of OVEC in AEP Ohio's rates. For its part, the Company's intention would then be to continue to include the OVEC contract in the PPA Rider beyond the term of this *ESP III*, to the same extent that the Commission is committed, up front, to this long-term hedging arrangement.

Third, AEP Ohio submits that it is unreasonable for the Commission to defer approval of OVEC in the PPA Rider until resolution of uncertainty relating to PJM market reforms, environmental regulations and federal litigation. All of these areas could take considerable time and may well end up causing wholesale market prices to increase, which would mean that it would be too late for the PPA Rider to be taken up at that point. A clear and decisive ruling on

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[2] *ESP II* Opinion and Order at 19 (Mar. 18, 2009). Recently, that Commission decision regarding REPAs has effectively been codified by the General Assembly in SB 310 through the enactment of R.C. 4928.641. Traditionally, the same process applies to long-term fuel contracts, the costs of which are recovered through a fuel adjustment clause. Specifically, when a new long-term fuel contract is formed during an audit period, there is a one-time prudence review; after that, only the administration of the contract terms are subject to ongoing prudence review (in addition to the costs being subject to ongoing financial audits).

[3] Indeed, the Commission previously decided to affirmatively and explicitly permit recovery of OVEC/Lawrenceburg demand charges separately from base generation rates and through the FAC for the period of 2009-2011 as part of its *ESP I* decision, which has long since been final and nonappealable. *ESP I*, Opinion and Order at 14-15, 51-52 (Mar. 18, 2009).

the PPA Rider, which involves important and urgent issues of Ohio energy policy, is presently needed by this Commission.

Regarding the PJM markets, it is obvious that they are flawed and are in the ongoing process of being reformed. Staff witness Dr. Choueiki – the biggest supporter of the PJM markets in this case – acknowledged that he and the Commission have an ongoing list of reforms that are either pending or still needed regarding the PJM markets. Most, if not all, of these reforms will result in increasing market prices:

- Impose more restrictions on demand response resources so that all generation resources are on equal footing. (Tr. XII at 2834, 2964, 2977.)
- Performance incentives are needed for generation resources. (*Id.* at 2963.)
- PJM needs to restrict the market construct where bidders are permitted to engage in speculative participation in the Base Residual Auction only to cover the underlying obligation through participation in the incremental auction. (*Id.* at 2965-66.)
- Restrict generation resource imports into PJM to ensure that firm transmission is committed. (*Id.* at 2979.)
- Pursue fuel diversity as a top priority as FERC/PJM considers the Polar Vortex lessons learned. (*Id.* at 2980.)
- Reform artificial price suppression that may lead to uneconomic unit retirements. (*Id.* at 2983.) In the history of the RPM capacity market, none of the eleven Base Residual Auctions as applicable to Ohio have reached the PJM-designed goal of net CONE; currently, net CONE is $382/MW-day as applicable to Ohio. (*Id.* at 3025, 3032-34; AEP Ohio Ex. 27; AEP Ohio Ex. 31.)

All of these reforms will likely take a significant amount of time and either come with a price tag or increase PJM market prices if successful.

OCC witness Wilson agreed there would be a price tag for transmission fixes associated with plant retirements that may occur, but acknowledged that he did not evaluate the impact of his recommended approach or compare that price tag to the potential cost of the PPA Rider. (Tr. X at 2516.) Exelon witness Campbell also recommends exclusive reliance on PJM markets and, if there are reliability issues, to build out transmission facilities to address the situation. (Tr. VII at 1630-32.) While he acknowledges it would be fair to consider the costs associated with such solutions, he has not done so and does not recommend considering the cost of transmission fixes in deciding whether to adopt the PPA Rider. (*Id.* at 1635-37.) Dr. Choueiki also testified that there are always reliability issues when coal plants retire and transmission fixes have definite price tags – sometimes hundreds of millions of dollars. (Tr. XII at 3000.)

AEP Ohio is not being unduly critical of the reforms needed in the PJM markets – the Company is working to achieve many of the same objectives. But the point in this context is to realize that many reforms are needed and that most – especially the capacity market reforms – will occur over a considerable period of time, may occur in a piecemeal fashion and ultimately tend to increase PJM market prices if successful. AEP Ohio is offering OVEC as a hedge now but there is no guarantee that it will be available in the future, especially if market prices increase as a result of the Commission waiting for the dust to settle in these three areas. Moreover, as the Commission directed in the Opinion and Order (at 27), AEP Ohio is not supposed to forego any reasonable opportunity to divest or transfer the OVEC asset. Accordingly, the Commission should not delay ruling on this important and urgent issue of Ohio energy policy based on a hope that uncertainty will be eliminated in the near future. To the extent significant developments occur in these areas that bring clarity, it is likely to mean that the Company will pursue other options and it will be too late for the Commission to capture the long-term customer benefits associated with OVEC.

Finally in this regard, the fourth reason the Commission gave for deferring a ruling on OVEC is that some stability exists now due to SSO auction strategies of laddering and staggering as well as fixed rate offerings of CRES providers. The evidence of record showed that, even with the SSO auction design tools of laddering and staggering, the auction clearing prices still follow market price changes up and down. (Tr. XII at 2810.) It would be misguided to conclude that an additional tool for rate mitigation should be categorically excluded, especially given the flaws and limitations of the existing mitigation tools.

Mr. Allen demonstrated in his rebuttal testimony that the laddering/staggering approach only partially mitigates rate volatility and does not mitigate fundamental changes in market rates. (AEP Ohio Ex. 33, at 2-3; Ex. WAA-R1.) Mr. Allen also pointed out another obvious limitation to the auction design solution: it can only help for non-shopping customers and does not mitigate rates for shopping customers or those participating in governmental aggregation programs. (*Id*.)

AEP Ohio witness McDermott rebutted Dr. Choueiki's claim that auction design should be used exclusively to mitigate rate volatility:

> I agree that the SSO auction is an effective method of mitigating price volatility in the shorter term electricity markets and the SSO auction design can benefit customers by mitigating those shorter term price fluctuations. *There is, however, no basis to conclude that the SSO auction mitigates longer term market changes. The SSO auctions are not designed to provide price protection from longer-term market trends like the physical hedge found in the PPA.* Moreover, the SSO auctions apply only to non-shopping customers. Even the limited protection from short-term volatility achieved by the auction design is not applicable to shopping customers or those being served by governmental aggregation.

(AEP Ohio Ex. 32, at 11 (emphasis added).) Dr. McDermott reasonably drew the obvious and compelling conclusion that, in light of these limitations of auction design, the Commission "should evaluate the PPA Rider's potential effect on volatility based on its own merits quite apart from the SSO auction design questions." (*Id*.)

Another similarly flawed argument advanced by CRES intervenors is that fixed generation price offers in the market adequately manage rate volatility such that the PPA Rider is simply not needed. For example, Exelon witness Campbell maintains that there is no need for

AEP Ohio to provide a hedge because CRES providers have a number of competitive offerings geared toward customer goals and objectives, including their risk tolerance or desire for a market hedge. (Exelon Ex. 1, at 15.) He also maintained that CRES providers "can offer a stable, long term, fixed price at a much lower rate that is reflective of market prices." (*Id*. at 16.) As Exelon witness Campbell himself admitted, however, any CRES offer for a fixed price reflects a risk premium to account for the risk of having to honor the price when market prices are higher. (Tr. VII at 1604-06.) Dr. Choueiki also agreed that a CRES fixed price offer reflects a price premium. (Tr. XII at 3017.) By contrast, the PPA Rider involves a straight differential between cost and market without an additional premium.

Factually, Mr. Allen demonstrated that CRES providers are not offering long term stable offers to residential customers – using data from the Commission's Apples-to-Apples website. (AEP Ohio Ex. 33, Ex. WAA-R3.) In reality, the vast majority of offers (72.4%) are for terms of 12 months or less and there are no offers in the AEP Ohio service territory exceeding 36 months. The short-term nature of these contracts results in customers needing to sign new contracts on a regular basis which creates volatility for customers as they transition from one contract to another. Based upon a review of CRES offerings of comparable terms, Mr. Allen showed that this transition can result in significant volatility in the form of generation rate changes of at least 9.7% and up to 48.4% over the most recent 12-month period. (*Id*. at Ex. WAA-R4.) Mr. Allen also demonstrated that the same phenomenon can occur for customers served by CRES providers through governmental aggregation. As shown in Mr. Allen's Exhibit WAA-R5, the CRES pricing for customers served under the Upper Arlington governmental aggregation program will see their price increase this year from 5.545 ¢/kWh to 7.84 ¢/kWh, or just over 41%. Finally in this regard, Mr. Allen observed that the risk of shopping customers seeing significant price volatility is exacerbated by the fact that many CRES contracts for residential customers include a rollover provision that automatically enrolls the customer in a new market based variable rate plan or a fixed rate plan unless the customer takes action. In that common scenario, unless the customer takes proactive action, a new and potentially higher rate unilaterally charged by the CRES provider will automatically apply. (*Id.* at 5.)

AEP Ohio submits that the PPA Rider will stabilize rates even for customers that temporarily have a fixed price contract. Initially, the Company notes that the record evidence showed – using data from the Commission's Apples-to-Apples website – that CRES providers are simply not offering long term stable offers to residential customers. (AEP Ohio Ex. 33, Ex. WAA-R3.) In reality, the vast majority of offers (72.4%) are for terms of 12 months or less and there are no offers in the AEP Ohio service territory exceeding 36 months. (*Id*.) Moreover, the short-term nature of the fixed rate contracts results in customers needing to sign new contracts on a regular basis, which creates volatility for customers as they transition from one contract to another. Based upon a review of CRES offerings of comparable terms, Mr. Allen showed that this transition can result in significant volatility in the form of generation rate changes of at least 9.7% and up to 48.4% over the most recent 12-month period. (*Id*. at Ex. WAA-R4.)

Thus, when considered over anything more than a short-term basis, it is a foregone mathematical conclusion that the PPA Rider will add rate stability for all customers including fixed rate contract customers.[4] As AEP Ohio witness Dr. McDermott succinctly stated:

> [I]f the Commission wishes to provide longer term hedges for all customers it appears that the PPA is the only method currently proposed in AEP Ohio's service territory to do so. Further, as I explain below, some regulators have

[4] Even on a short-term basis, the fact is that any CRES offer for a fixed price reflects a risk premium to account for the risk of having to honor the price when market prices are higher. (Tr. VII at 1604-06; Tr. XII at 3017.) By contrast, the PPA Rider involves a differential between cost and market without an additional premium. So, blending in the hedge offered through the PPA Rider even with short-term fixed rates is likely to lower rate volatility for those customers.

> determined that longer term hedges do serve the public interest and all customers, including those that have chosen to hedge their short-term risk using contracts from competitive suppliers, should benefit, and pay for, those longer term hedges.

(AEP Ohio Ex. 32, at 15.) The PPA Rider has benefits to offer to all customers, including the narrow subset of customers that have short-term fixed rate contracts, and should not be deferred because there are other limited tools to promote rate stability.

II. The Commission's modifications to the Distribution Investment Rider (DIR) component of the ESP are unreasonable and should be changed or clarified on rehearing.

The DIR was initially approved in the *ESP II* case to facilitate the timely and efficient replacement of aging infrastructure to maintain and improve service reliability. Opinion and Order at 46-47. In its *ESP II* Opinion and Order, the Commission found that "adoption of the DIR and the improved service that will come with the replacement of aging infrastructure will facilitate improved service reliability and better align the Company's and its customers' expectations." *ESP II* Opinion and Order at 46. The Company's proposal to include the DIR as part of *ESP III* was intended to continue reliability-impacting infrastructure investment and better align the Company's and customers' interests.

A key factor to understand about the need to keep investing in the DIR was provided by AEP Ohio witness Moore, who explained that the DIR only provides recovery of a carrying charge on new capital investments that are over and above the net distribution plant in service as of the date certain in the Company's last base distribution rate case. (*See* AEP Ohio Ex. 14 (updated Ex. AEM-2).) Company witness Dias explained that aging infrastructure is a primary cause of customer outages and reliability issues; the DIR facilitates and encourages investments to maintain and improve distribution reliability, and align customer expectations and the expectations of the distribution utility. (AEP Ohio Ex. 4 at 9.) Mr. Dias discussed the DIR benefits when explaining the value of replacing assets often more than fifty years old, the strength and wind/ice resistance of new distribution lines, and the ability to consider the needs of hospitals, fire, and police stations to ensure that electric service to these facilities can be restored quickly when outages occur. (*Id*. at 14.) In short, there is an established need to invest in the distribution system to maintain and improve reliability, and the DIR provides the Company needed capital carrying costs for that crucial incremental reliability-impacting distribution investment to help ensure continued investment in the distribution system. (*Id.* at 9.)

The Company proposed as part of *ESP III* to modify the DIR mechanism that was previously adopted in *ESP II* in three primary respects: (1) that the carrying charge calculation be modified to reflect that the depreciation component of the carrying charge be calculated based on gross plant in order to reflect the return of the rate base (AEP Ohio Ex. 13, Direct Test. of Andrea E. Moore, at 6); (2) that certain general plant items be included in the DIR (AEP Ohio Ex. 4, Direct Test. of Selwyn J. Dias, at 16; AEP Ohio Ex. 13, Direct Test. of Andrea E. Moore, at 5); and (3) that a gross-up factor be added to reflect the current assessment contribution for the OCC and PUCO budgets (AEP Ohio Ex. 13, at AEM-2). The first Company proposal was not opposed and the Commission did not modify it, so it was adopted. Opinion and Order at 47, 95. The second and third proposals were opposed, and the Commission rejected them. Opinion and Order at 46.

Beyond the three proposed structural changes to the DIR, the Company proposed annual DIR revenue caps of $156 million in 2015, $192 million in 2016, $220 million in 2017, and $103 million for January through May 2018 (the $103 million is equivalent to $247 million on an annual basis for 2018), for a grand total of $671 million. (AEP Ohio Ex. 13, Direct Test. of Andrea E. Moore, at 6.) As further discussed below, the Opinion and Order significantly reduced the Company’s proposal and adopted DIR revenue caps of $124 million for 2015,

$146.2 million for 2016, $170 million for 2017, and $103 million for January through May 2018, for a total of $543.2 million. Opinion and Order at 47. The following table compares the Application with the Opinion and Order with respect to the annual DIR revenue caps:

	2015	**2016**	**2017**	**2018**	**TOTAL**
Application	$156 M	$192M	$200M	$103M	$671M
Opinion & Order	$124M	$146.2M	$170M	$103M	$543.2M
Difference	$ 32M	$ 45.8M	$ 30M	$0	$127.8M

These annual revenue cap reductions and the impact on the Company's capital spend are extremely problematic for the Company and would significantly impair its ability to continue to make reliability-impacting distribution investments, as is discussed in more detail below.

In addition to addressing the Company's proposed DIR modifications, the Commission also adopted Staff witness McCarter's six recommendations regarding the DIR: (1) to provide detailed account information regarding plant in service being recovered through other distribution riders, (2) to use jurisdictional allocations and accrual rates from the prior AIR case, (3) to include reconciliation between functional ledgers and FERC form 1 filings, (4) to report the DIR revenue collected by month to show compliance with the annual revenue caps, (5) to report and quantify any changes to the Company's capitalization policy in the DIR filing preceding the change, and (6) to file an updated depreciation study by November 2016 with a study plant date of December 31, 2015. Opinion and Order at 46-47. Finally, the Commission adopted one of OCC's proposed DIR modifications to revise the property tax calculation to eliminate the cumulative amortization of the excess depreciation reserve. *Id.* at 46.

On rehearing, while the Company continues to believe that its DIR proposal was reasonable, it is not challenging most of the Commission's DIR modifications, but does respectfully disagree with the Commission's significant (and potentially mistaken) reduction of the annual DIR revenue requirement caps and the Commission's broad refusal to add general plant to the DIR when the Company was seeking a targeted addition overseen by Staff. These modifications of the proposed DIR render it significantly less beneficial to customers and hamstring the Company's efforts to make reliability-impacting investments to the distribution infrastructure. As further discussed below, the Company submits that the Commission-ordered reductions are unjustified by the record and were unduly drastic.

Accordingly, the Company requests that the Commission adopt one or more of the following options to better align the Company's and customers' reliability expectations and interests: (A) reinstate the Company's proposed annual revenue caps; (B) adjust the DIR revenue caps listed on Page 47 of the Opinion and Order so that they properly reflect the Commission's stated intention to set the annual revenue caps based on the level of growth of three to four percent as permitted for the DIR in the ESP 2 Case; (C) clarify that the Commission's intention in the *ESP II* decision was to adopt an $86 million annual revenue cap for 2012 without proration, which would increase the carryover amount that would apply to 2015 and beyond; and/or (D) due to the immediate and substantial impact on the Company's capital commitments and investment in Ohio, the Company asks that the Commission issue an expedited rehearing decision on these DIR issues, to the extent it does not issue a full rehearing order within the normal 30-day timeline required by R.C. 4903.13.

A. The Commission should reconsider its decision to reduce the Company-proposed DIR revenue caps and its denial of the Company's proposal to include general plant within the DIR.

Neither intervenors nor the Staff advocated specific reductions to the annual revenue caps and the record is consequently devoid of resulting impacts from the actual reductions adopted in the Opinion and Order. The only known effects are the investment and reliability impacts described in the Company's testimony that relate to the AEP Ohio's proposed annual revenue caps. AEP Ohio asks that the drastic revenue cap reductions adopted in the Opinion and Order be modified and that the Company's proposed revenue caps be reinstated on rehearing.

In its Opinion and Order, the Commission concluded that the Company's DIR proposal in this case "far exceeds" the justification offered and accepted by the Commission in *ESP II* when initially adopting the DIR. Opinion and Order at 46. The Commission also characterized the Company's DIR proposal as a request to "significantly increase" the amount to be included in the DIR. As further discussed below, the Company respectfully disagrees with the Opinion and Order findings in this regard and is concerned that the Commission made an adjustment believing it to represent the General Plant additions. That is not the case; in fact, the Company's request in this case is aligned with the *ESP II* approach and the Opinion and Order is not. Accordingly, AEP Ohio respectfully requests that the Commission reconsider the drastic cuts adopted in the decision. If the Commission is not willing to adopt the Company's proposed DIR revenue caps but would like to better gauge and understand the actual impacts of various levels of DIR revenue cap reductions on the Company's incremental reliability infrastructure investments (including the specific cuts adopted in the Opinion and Order), it could alternatively grant rehearing and receive further testimony to better understand the impacts. As it stands now, however, the impact of the cap reductions adopted in the decision is substantial yet lacking a basis in the record.

1. The Company's proposed annual revenue caps should be adopted on rehearing.

A key aspect of the DIR is that it allows the Company to maintain the current level of reliability by replacing aging infrastructure before it fails. Company witness Dias testified that reliability is a moving target, and without continuous improvement, the general reliability of the distribution system may unintentionally decline over time. (AEP Ohio Ex. 4, at 3.) Certainly the prospect of a static revenue cap as between 2014 and 2015 – at the level of $124 million – would have significant implications for capital reliability spend (a static revenue cap implies that the net plant is essentially unchanged from one year to the next). By contrast, the Company's proposed revenue caps were fully explained and vetted in the record as supporting a reasonable and necessary level of additional reliability-impacting investment.

The Opinion and Order's "flat line" 2015 impact is exacerbated by the timing of the Commission's decision, which was not issued until late February after the Company's capital budget was already set for the year and project commitments were well underway in line with the plan filed with the Commission after consultation with Commission Staff. The Company filed its ESP in December 2013 and – per the ESP statute and rules – anticipated a decision prior the end of the third quarter of 2014. Since no decision was forthcoming, the Company was forced to estimate the DIR revenue cap for 2015, establish its capital budget, and make contractual commitments to implement projects.

There was no argument by an intervening party or other basis in the record or otherwise for the Company to presume that no additional revenue growth would be provided in 2015. As a practical matter, pending capital projects cannot be instantaneously pulled back based on the Commission's decision, without adverse financial impact on the Company. It is logistically difficult – and financially harmful – for the Company to abruptly pull back on pending capital projects that are in progress. Of course, the negative reliability impact of doing so is also harmful to customers; cutting off additional investment in the DIR will not deliver the same level of reliability that customers currently experience. Given these unique and unfortunate circumstances, the Company is "out on a limb" financially and requests that the Commission quickly correct the situation on rehearing through adoption of the Company's proposed annual revenue caps.

2. The targeted proposal for inclusion of certain general plant should be permitted on rehearing.

The proposed expansion of the DIR to include general plant is an extension of the underlying goal of investing in distribution infrastructure with a focus on replacing aging infrastructure to meet customer reliability expectations. The improvements to the service centers and in particular the replacement of the practically obsolete communications system will directly benefit customer restoration efforts at the time of outages when customers are most concerned with reliability efforts. (AEP Ohio Ex. 4, Direct Test. of Selwyn J. Dias, at 19; Tr. II at 432.) Contrary to the Opinion and Order's finding that the Company's proposal exceeds the original purpose of the DIR, inclusion of targeted general plant, as discussed above, is intended to have a direct impact on customers and reliability. OCC witness Effron agreed that, while not an operations man, the radio system is important in the restoration effort of the distribution system after a major storm. (Tr. XII at 2747.) Staff witness McCarter also made clear that the Staff position is not a complete prohibition on inclusion of general plant, just a careful review of what is included in the DIR. On cross-examination, Staff witness McCarter was uncomfortable agreeing to the appropriateness of any general plant recovery in the DIR as a general matter, but did admit that certain parameters put in place may help resolve some of the items requested in general plant to be recovered in the DIR. (Tr. IX at 2294.) Ultimately, Staff witness McCarter acknowledged that she may have been able to include certain investments categorized as general plant, namely the radio system, in the DIR if they are fully reviewed by Staff. (Tr. IX at 2295.)

The majority of the infrastructure characterized as targeted general plant in this proceeding includes the service centers and the radio communications system. (AEP Ohio Ex. 4, Direct Test. of Selwyn J. Dias, at 16, 19.) Company witness Dias testified that the service centers directly support the activities of the front-line employees and are used for the infrastructure they have to maintain and construct. (Tr. II at 344.). He pointed out that some of these facilities were built in the World War II era and need work. (*Id.*)

Mr. Dias also testified that the radio system is "an integral part of the reliability and the infrastructure that we have to maintain." (Tr. II at 345.) OCC asserted that the record did not contain any proof that the general plant additions could be quantified in the DIR. (OCC Br. at 87.) But a closer inspection shows that Mr. Dias, in fact, testified that the service reliability improvement from replacing the radio system could be quantified with a measurement. (Tr. II at 345-346.) Mr. Dias's testimony dealt with his comprehensive reliability plan focused on meeting the customer's expectations. As he testified, meeting the customer expectations is going to require the DIR as proposed. (Tr. II at 455.)

Alignment of customer and Company reliability expectations is the purpose of approving infrastructure improvement riders under R.C. 4928.143(B)(2)(h). General plant like the service center investment and the important radio system are part of that comprehensive plan. Accordingly, the Commission should grant rehearing and reinstate the targeted expansion of the DIR to include the reliability-impacting general plant projects and funding enumerated by Mr. Dias.

B. Alternatively, the Commission should correct the mistaken DIR revenue caps listed on Page 47 of the Opinion and Order so that they properly reflect the Commission's stated intention to set the annual revenue caps "based on the level of growth of three to four percent as permitted for the DIR in the ESP 2 Case." Opinion and Order at 47.

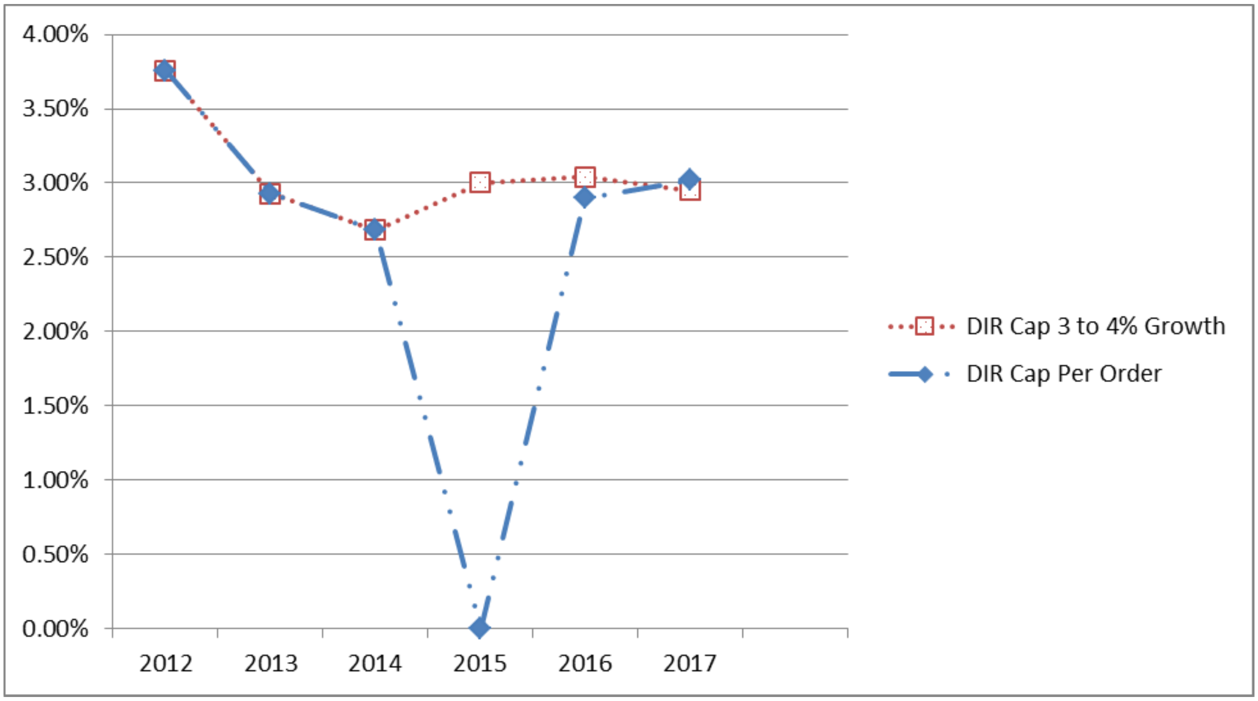
In reducing the Company's proposed annual revenue caps, the Commission stated that it "determined the annual DIR amounts based on the level of growth of three to four percent as permitted for the DIR in the *ESP 2 Case*." Opinion and Order at 47. As reflected in AEP Ohio witness Moore's testimony, the Commission was correct in referring to a 3-4% level of growth in connection with *ESP II*. More specifically, after introduction of the DIR, distribution revenues grew approximately 3% in the first year of the ESP II term, 2.7% in the second year.[5]

Although 3-4% growth was less than proposed by the Company, it was reasonable and appropriate for the Commission to determine that continuation of such moderate distribution revenue growth would advance the purposes of the DIR. Unfortunately, the actual revenue caps adopted in the Opinion and Order do not correspond to the explicitly-stated intention to continue the 3-4% growth rate adopted in *ESP II*. Indeed, using the numbers in the Opinion and Order produces a far different result. When the Commission's actual numbers are applied to the same calculation for the next three years it results in a <u>0% growth</u> in distribution revenue for 2015, followed by a more reasonable 2.9% growth in 2016 and 3% growth in 2017.[6]

The following illustration shows the significant capital investment interruption that would be caused by the Opinion and Order:

[5] These simple calculations are evident from page 2 of AEM-2 (part of AEP Ohio Ex. 13, Direct Test. of Andrea E. Moore). The 2013 growth calculation is derived from observing that the base distribution and DIR revenue cap total for 2013 ($642 million plus $104 million) is 3% more than the same total for 2012 ($638 million plus $86 million); and the 2014 growth calculation is derived from observing that the base distribution and DIR revenue cap total for 2014 ($642 million plus $124 million) is 2.7% more than the same total for 2013 ($642 million plus $104 million).

[6] Again, these simple calculations are evident from page 2 of AEM-2 (part of AEP Ohio Ex. 13, Direct Test. of Andrea E. Moore). The 2015 growth calculation is derived from observing that the base distribution and DIR revenue cap total for 2015 ($642 million plus $124 million) is 0% more than the same total for 2014 ($642 million plus $124 million); the 2016 growth calculation is derived from observing that the base distribution and DIR revenue cap total for 2016 ($642 million plus $146 million) is 2.9% more than the same total for 2015 ($642 million plus $124 million); and the 2017 growth calculation is derived from observing that the base distribution and DIR revenue cap total for 2017 ($642 million plus $170 million) is 3% more than the same total for 2016 ($642 million plus $146 million).



If the Commission had intended these annual cap levels, it would not have referred to continuation of *ESP II*'s 3-4% growth rate. It would have, instead, referred to a much lower and more volatile rate of 0-3% growth; as it stands now, the stated intention and the revenue cap numbers simply do not match and leave a large hole that needs to be filled in. Given that the revenue caps listed in the Order do not match three different descriptions of the Commission's intent regarding the DIR (discussed below), the revenue caps may have been incorrectly listed on Page 47 of the Opinion and Order and could easily be corrected on rehearing.

As it stands now, however, there was no basis in the record to adopt such drastic reductions in the proposed annual revenue caps. Neither Staff nor any intervenor advocated a flat revenue cap for 2015. If there were a party advocating for a flat line revenue cap or any other advanced notice that the Commission was considering such an option, the Company would have demonstrated the ill effects of doing so in the record. Since the record was devoid of the zero-growth option until issuance of the Opinion and Order, we must now discuss the resulting problems without the benefit of responding to an argument raised at hearing.

Nonetheless, it is a self-evident truism that, absent a base distribution rate case, growing the annual total distribution revenue (base distribution plus DIR revenue) is the only way to support additional investment each year. That is the very purpose of the DIR. As the Commission observed in the *ESP II* decision, the DIR is "incentive ratemaking to accelerate recovery of the Company's investment in distribution service." *ESP II* Opinion and Order at 46. Even more explicitly, the Commission stated in the *ESP II* decision that "[w]e believe that it is detrimental to the state's economy to require the utility to be reactionary or allow the performance standards to take a negative turn before we encourage the electric utility to proactively and efficiently replace and modernize infrastructure and, therefore, find it reasonable to permit the recovery of prudently incurred distribution infrastructure investment costs." *Id.* at 47. Not only does the stated intent of the Opinion and Order (of 3-4% growth) conflict with the adopted annual DIR caps, but the adopted caps are simply inadequate to support investment and growth.

At the outset, a generic illustration of this concept is helpful to begin discussing how the DIR annual revenue caps support new investment provided they continue to grow each year. Generally, for example, approximately every $20 million increase in the annual DIR revenue caps will support $100 million of new capital investment above normal depreciation levels. By contrast, if the annual revenue cap is flat and incorporates no increase, investment at depreciation levels is all that is supported.

Using the Company's current depreciation level referenced in Exhibit AEM-2 of 3.68%, this means that a flat DIR revenue cap approach would only support $147 million of capital spend, which would take the Company back to a spending level at the time the DIR was first instituted.[7] In addition, under the scenario of just spending the current depreciation level of $147 million, the resulting revenue requirement would be $134 million, which is $10 million greater than the approved revenue cap for 2015 of $124 million.[8] That result clearly does not match the Commission's stated expectation of permitting the Company to proactively replace aging infrastructure in order to maintain and improve service reliability over the ESP term. Opinion and Order at 47.

To further consider this concept with actual publicly-available numbers, if the Company's September 2014 Plant in Service levels from its recent DIR update filing (Case No. 14-1696-EL-RDR) are plugged into Exhibit AEM-2, the result shows a revenue requirement of $124.2 million for that historical level of investment.[9] This means that the $124 million DIR revenue cap adopted in the Opinion and Order for 2015 has already been used up as of last September and that no new capital investment, beyond the normal level of depreciation, is supported by the 2015 DIR cap.[10] Matters get worse if the historical rate of investment is projected through the end of 2014, which shows that the adopted DIR cap for 2015 is already inadequate for the current level of investment. In particular, the illustrative revenue requirement

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[7] See Attachment A to the Application for Rehearing, which lists the sources of information used in the illustrative $147 million calculation. The fact that $147 million is the level of capital investment prior to institution of the DIR is shown by Staff's January 16, 2014 Comments in the Company's 2014 DIR Work Plan case. (Case No. 13-2394-EL-UNC, Staff Comments at 4.)

[8] See Attachment B to the Application for Rehearing, which lists the source for the information used in the illustration.

[9] Attachment C to this Application for Rehearing shows the updated Ex. AEM-2 based on the Company's September 2014 Plant in Service. The Attachment lists the source for the information used in the illustration, which is based on the Company's most recent DIR update filing, Case No. 13-2394-EL-UNC.

[10] Although there are external factors other than the annual revenue caps that affect capital spending under the DIR (such as depreciation, tax effects, any rollover amount, see Section C below, etc.), the issue being challenged in this proposition of the Company's rehearing application are the reduced annual revenue caps adopted in the Opinion and Order. Thus, the comments and statements made herein are not absolute or without qualification but relate to the direct operation and impact of the annual revenue caps themselves.

for the end of 2014 (not even accounting for the investments made in 2015) shows that a revenue requirement that already exceeds the adopted $124 million cap by $9 million.[11] Of course, the even more troubling reality for AEP Ohio is that it has continued to invest in its distribution system to date in 2015 while waiting for an ESP decision.

If left unchanged, this situation forces the Company to cut its losses and pull back on capital investment in Ohio, which not only involves a reduced investment and potential reliability impacts but also could mean loss of contractor jobs currently sustained by the DIR funding. These are the same contractors that help to provide a rapid response to storm related outages. Such a result cannot be what the Commission intended when it stated in the Opinion and Order that "[w]e find this to be a reasonable level to allow AEP Ohio to continue to replace aging distribution infrastructure in order to maintain and improve service reliability over the term of this ESP." Opinion and Order at 47. As a related matter, the Opinion and Order also states that "although AEP Ohio has not committed to refrain from filing a distribution rate case application during the ESP period, the Commission's approval of the continuation of the DIR, ESRR, and other distribution-related riders should enable the Company to hold base distribution rates constant over the ESP period, while making significant investments in distribution infrastructure and improving service reliability." *Id.* at 95. However, as demonstrated above, the caps outlined in the order do not allow for significant investments in distribution infrastructure, in turn not permitting the focus on the DIR programs as historically laid out in the Company's

[11] See Attachment D to the Application for Rehearing, which lists the source for the information used in the illustration.

DIR plans. More specifically, a DIR revenue requirement of $150.5 million is needed to support the Company's filed DIR Work Plan for 2015 (Case No. 14-2275-EL-UNC).[12]

In sum, the Commission should increase the 2015 DIR revenue cap to a level closer to its stated intention of 3-4% growth. Of course, the most glaring and problematic year presented is 2015, since it currently has a cap that involves no increase over 2014, does not support additional investment in 2015, and ignores the Company's compliance with the 2015 DIR plan on file with the Commission. Accordingly, the Commission should increase the annual DIR revenue caps to reflect at least a modest level of growth and investment, beginning with 2015. If the Commission were to adopt DIR revenue caps at the lower end of its stated intention (3%) the annual caps would be $147 million in 2015, $171 million in 2016, $195 million in 2017 and $92 million in 2018 for a total of $605 million (approximately 10% less than the level requested by the Company).[13]

C. It would also partially offset the adverse effects of drastic annual revenue cap reductions to clarify in this context that the Commission's intention in the *ESP II* decision was to adopt an $86 million annual revenue cap for 2012 without proration, which would produce a significant carryover amount that would also help alleviate the problem for 2015 and beyond.

Given the Opinion and Order's drastic cuts to the DIR revenue caps, it is of increased importance to definitively resolve the issue of carry-over from *ESP II* revenue caps. In approving the DIR with certain modifications as part of the *ESP II* decision, the Commission

[12] See Attachment E to the Application for Rehearing, which lists the source for the information used in the illustration.

[13] The 2015 cap equals the 2014 cap of $124 million plus 2014 distribution revenue of $642 million + $124 million times 3% or $147 million. The 2016 cap equals the 2015 cap of $147 plus 2015 distribution revenue of $642M + $147 million times 3% or $171 million. The 2017 cap equals the 2016 cap of $171 million plus 2016 distribution revenue of $642 million + $171 million times 3% or $195 million. The 2018 cap equals the 2017 cap of $195 million plus 2017 distribution revenue of $642 million + $195 million times 3% or $220 million - $92 million for the first five months of the year.

approved the Company's annual revenue caps of $86 million for 2012, $104 million for 2013, $124 million for 2014 and $51.7 million for the period January 1 through May 31, 2015, for a total of $365.7 million. While the total of the annual revenue caps is a hard limit on the Company's recovery during an ESP term, the individual annual caps are more flexible. Specifically, if the revenue requirement is less than the annual cap, the unused portion can be banked and carried over to the next annual period; whereas, if the revenue requirement exceeds the annual cap for a given year, the overage is taken out of the cap in the following annual period. As the Commission described this feature of the DIR when it originally approved the rider as part of *ESP II*:

> As the DIR mechanism is designed, for any year that the Company' investment would result in revenues collected which exceed the cap, the overage would be recovered and be subject to the cap in the subsequent period. Symmetrically, for any year that the revenue collected under the DIR is less than the annual cap allowance, then the difference shall be applied to increase the cap for the subsequent period.

ESP II Opinion and Order at 42-43. In fact, for each of the annual periods that have been completed under *ESP II* (2012-2014), the revenue requirement has been less than the annual revenue caps. Per the terms of the approved DIR, the underspent amount from 2012-2014 is still available and carries over to 2015 which, of course, is still in progress

The realized annual revenue requirements during the completed annual periods of *ESP II* were $29.1 million for 2012, $87.2 million for 2013, and $120.5 million for 2014, as shown in the Company's latest DIR filing in Case No. 14-1696-EL-RDR. It is not clear whether the Commission intended to prorate the $86 million revenue cap for 2012 (based on an effective date of August 2012), so the actual revenue cap for 2012 could either be $86 million per the order or $35.8 million (5/12 of $86 million). As such, the cumulative underspend that carries over to

2015 and beyond is either $77.1 million or $26.9 million.[14] If the Commission clarified on rehearing that the *ESP II* decision was intended to adopt an $86 million revenue cap for 2012 without proration, that would help alleviate the current problem for 2015 and beyond.

D. Due to the immediate and substantial impact on the Company's capital commitments and investment in Ohio, the Company asks that the Commission issue an expedited rehearing decision on these DIR issues, to the extent it does not issue a full rehearing order within the normal 30-day timeline required by R.C. 4903.13.

As explained above, the need to address the adverse impacts of the Opinion and Order on capital expenditures on the DIR is urgent. Accordingly, AEP Ohio requests that the Commission rule promptly on its request for rehearing and increase the cap levels for DIR investments to the reasonable levels that the Company has requested, in order to avoid those adverse impacts. A ruling within the normal 30-day period for rehearing that addresses the DIR investment cap levels would be sufficient to enable the Company to continue to make improvements to its distribution infrastructure without significant disruption in the field in the short term. It would also avoid impairment of the Company's capabilities to continue to make improvements in an efficient manner over the long term.

The Company recognizes that, due to the complexities involved in the rehearing process for a proceeding of this type, the Commission may conclude that it needs more time than the 30 days allotted in the normal course for rehearing in order to adequately consider the range of issues parties raise in their applications for rehearing.

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[14] Per operation of the *ESP II* decision which adopted the carry-over feature of the DIR, it is clear that at least $26.9 million of rollover exists for 2015 and beyond. This portion of the rehearing requests a clarification of the intention of the *ESP II* decision relative to whether the Commission intended to prorate the 2012 revenue cap of $86 million; if not, the carryover balance may be $77.1 million. Either amount of carryover will help alleviate, but not completely resolve, the problems identified above in Sections A-B of Proposition II. This argument in Section C is designed to give the Commission another option to be used in a more comprehensive solution for the reduced annual DIR caps adopted in the Opinion and Order.

In that event, AEP Ohio urges the Commission to grant rehearing and rule on the more pressing DIR issues in an initial entry on rehearing and at the same time grant rehearing for the purpose of further considering the other issues raised on rehearing. In that way the Commission would address and resolve the approaching harms to the Company's distribution infrastructure investment program while allowing for continued consideration of other rehearing issues.

The Company submits that no parties' interests would be compromised by such an approach. In particular, no party's right to appeal to the Ohio Supreme Court any issue raised by any application for rehearing. The Court has made clear on several occasions that all issues raised on rehearing, regardless of the stage of rehearing when they are raised and ruled upon, are properly appealed after the Commission has ruled upon last application for rehearing or the last application for rehearing has been denied by operation of law. Accordingly, a decision modifying the Commission's Opinion and Order regarding the DIR will not prejudice any other party that may be opposed to that ruling. Should they wish to do so, any party would be free to seek further rehearing of that decision, and ultimately to appeal that decision, after the Commission has ruled upon all remaining issues raised on rehearing.[15]

III. The Opinion and Order's treatment of Rider IRP-D is unreasonable and unlawful in several respects and should be clarified or corrected.

The Commission approved AEP Ohio's existing interruptible service schedule in its *ESP II* proceeding. The requirements for eligibility and parameters of the existing Rider IRP-D include, among other things: the IRP-D customer must commit to a minimum of 1 megawatt (MW) of interruptible capacity and must enter into a firm service contract for capacity sufficient

[15] *In re Columbus S. Power Co.*, 128 Ohio St. 3d 402, 2011-Ohio-958, 945 N.E.2d 501, ¶ 12; *Senior Citizens Coalition v. Pub. Util. Comm.*, 40 Ohio St. 3d 329, 333 (1988) (holding that the date of denial of the last application for rehearing is the date on which the sixty-day appeal period set forth in R.C. 4903.11 begins to run).

to meet normal maximum power requirements under the applicable standard service rate schedule; the total amount of interruptible load for all IRP-D customers is capped at 525 MW, and new and expanded customer loads may be offered service under Rider IRP-D as part of an economic development or competitive response incentive. *ESP II* Opinion and Order at 26. Under the existing tariff, Rider IRP-D customers receive a credit of $8.21/kW-month, which equates to $274/MW-day. *Id.* In this proceeding, the Company initially proposed to eliminate its interruptible tariff, IRP-D, because the benefits of interruptible service relate, for the most part, to the provision of generation service. As a wires-only company, AEP Ohio believed it might not be best able to provide an interruptible service product. (AEP Ohio Ex. 13, Direct Test. of Andrea E. Moore, at 9.)

OEG objected in its testimony and initial post-hearing brief to the elimination of Rider IRP-D. Instead, OEG recommended that IRP-D, along with its 525 MW cap, be retained, that it remain available to all existing IRP-D customers, and that the $8.21/kW-month credit also be retained. (*See, e.g.*, OEG Br. at 25.) In addition, OEG proposed to expand the interruptible service options beyond Rider IRP-D. OEG proposed that a second interruptible service schedule option, with an interruptible credit equal to 50% of Net CONE (cost of new entry) (about $5.36/kW-month, or $179/MW-day), should be made available without limitation to all customers, both SSO and shopping, and with interruptions limited to 10 times during the months of June through September. (*Id.* at 25-26.)

In its post-hearing briefs, AEP Ohio indicated that it would not oppose retaining a modified version of Rider IRP-D – subject to important qualifications. (*See* AEP Ohio Br. at 71-73; AEP Ohio Reply Br. at 66-67.) The Company explained that it would not object to the Commission authorizing it to continue to offer a modified Rider IRP-D that would: (a) only apply to unlimited emergency interruptions; (b) be used for existing IRP-D customers and as an option for economic development purposes for new and expanded customer loads; (c) retain the existing subscription cap of 525 MW; (d) retain the existing $8.21 per kW-month credit; and (e) provide continued ability to fully recover the costs of any interruptible credits through the EE/PDR Rider. (AEP Ohio Br. 73.)

The Commission found that Rider IRP-D should be retained, but modified, to "provide for unlimited emergency interruptions[,] and that the $8.21/kW-month credit should be available to new and existing shopping and non-shopping customers." Opinion and Order at 40. The Commission also allowed that "[c]onsistent with its current practice, AEP Ohio should continue to apply for recovery of the costs associated with the IRP-D through the EE/PDR rider, until otherwise ordered by the Commission." *Id.* The Commission further directed "AEP Ohio [to] bid the additional capacity resources associated with the IRP-D into PJM's base residual auctions held during the ESP term, with any resulting revenues credited back to customers through the EE/PDR rider." *Id.*

As explained below, AEP Ohio has four concerns regarding the Commission's findings and directives regarding Rider IRP-D and the recovery of the costs of its $8.21/kW-month credit. AEP Ohio respectfully requests that the Commission clarify and modify its Opinion and Order's rulings regarding Rider IRP-D in several respects in order to address those concerns and avoid or correct the unreasonable and unlawful impacts of its Opinion and Order.

A. The Commission should clarify on rehearing that its Opinion and Order did not intend to eliminate the provisions of the existing IRP-D tariff that: (a) require customers to contract for not less than 1 megawatt (MW) of interruptible capacity; (b) cap the total interruptible power contract capacity for all customers served under Rider IRP-D at 525 MW. If it did intend to eliminate those provisions, the Opinion and Order is unreasonable and unlawful.

As noted above, page 40 of the Opinion and Order directs that Rider IRP-D and the $8.21/kW-month credit should be available to new and existing shopping and non-shopping customers. This modification significantly increases the eligibility criteria by allowing shopping customers to obtain the interruptible schedule's $8.21/kW-month credits.

AEP Ohio respectfully requests clarification on rehearing that the provision of the existing tariff that requires customers to contract for electrical capacity sufficient to meet normal maximum requirements but not less than 1 MW of interruptible capacity remains applicable. The Company also requests confirmation that the total interruptible power contract capacity for all customers served under Rider IRP-D bill remain capped at 525 MW (75 MW in the CSP Rate Zone and 450 MW in the OP Rate Zone), as is the case under the existing Rider IRP-D.

The 1 MW per customer minimum interruptible load commitment and the 525 MW aggregate cap for all customers have been, and remain, appropriate in order to support the relatively high $8.21/kW-month credit, on the one hand, and provide a reasonable limit on the burden that other customers will bear to pay the costs of the program, on the other hand. As noted above, the $8.21/kW-month equates to $274/MW-day. Only relatively large customers can provide sufficiently large amounts of interruptible capacity to warrant a credit of that magnitude. Accordingly, the 1 MW per customer minimum continues to make sense. Moreover, the 525 MW aggregate cap equates to $52.5 million in interruptible credit payments per year ($274/MW-day x 525 MW x 365 days/year). If that cap is eliminated, the potential burden on the remaining firm customers would become excessive and unreasonable. Accordingly, the 525

MW cap has provided, and continues to provide, a reasonable cap on the amount that other customers must pay for this program.

Consequently, AEP Ohio requests the Commission to clarify that the 1 MW per customer minimum interruptible capacity commitment and the 525 MW aggregate cap on all interruptible customer capacity eligible for the $8.21/kW-month remain applicable under Rider IRP-D and that the Opinion and Order did not eliminate them. If the Opinion and Order did eliminate those reasonable limitations, AEP Ohio contends, as explained above, that their elimination is unreasonable and unlawful and requests that the Commission reinstate them. The Commission should consider the financial impacts of uncapped exposure to the $8.21/kW-month interruptible credit before starting down a path toward that level of exposure. At a minimum, if the Commission intended to create such an exposure, it should grant rehearing for the purpose of holding a rehearing to take evidence regarding the potential financial impacts on customers who would pay for those increased costs.

B. The Commission should modify the method through which AEP Ohio recovers its actual costs of providing the IRP-D interruptible credits from the EE/PDR Rider to the Economic Development Rider (EDR). Reliance on the EE/PDR Rider as a cost-recovery mechanism will create an unreasonable and unlawful burden for customers paying the costs of the credits provided to Rider IRP-D customers. Moreover, recovery of those costs through the EDR is consistent with the substantial economic development purpose of the EDR.

The Commission should modify the method through which AEP Ohio recovers its actual costs of providing the IRP-D interruptible credits from the EE/PDR Rider to the Economic Development Rider (EDR). As noted above, the costs of the current IRP-D credits, even with the 525 MW cap, are substantial and are born by all customers who pay the EE/PDR Rider charges. Changing the cost recovery mechanism for the IRP-D credits to the EDR from the

EE/PDR Rider is necessary in order to assure that the costs of those credits are born by all customers, which is equitable.

Under the EE/PDR Rider mercantile customers currently have the choice to opt out of responsibility to pay EE/PDR Rider charges. And, the process by which mercantile customers may opt out will become further streamlined in 2017. That will significantly accelerate the migration of those customers away from the EE/PDR Rider. Thus, the opt-out feature of the EE/PDR Rider will shift the cost of the IRP-D credits away from mercantile to residential and non-mercantile customers, which is not equitable. Moreover, because the IRP-D customers are themselves mercantile customers, the opt-out feature of the EE/PDR Rider would allow current and future IRP-D customers to pay nothing for the benefits they receive from that tariff, which also would be inequitable.

Moreover, use of the EDR to recover the costs of Rider IRP-D is also appropriate because a central purpose of Rider IRP-D, in addition to enhancing reliability and encouraging energy efficiency and peak demand reduction, is the promotion of economic development. Indeed, the Commission specifically found, in its Order at 40, that "IRP-D offers numerous benefits, including the promotion of economic development and the retention of manufacturing jobs, and [thus] furthers state policy * * * ."

Accordingly, on rehearing, the Commission should change the method by which AEP Ohio recovers the cost of the IRP-D tariff from the EE/PDR Rider to the EDR.

C. The Commission must modify its directive that AEP Ohio bid capacity resources associated with Rider IRP-D into PJM's capacity auctions and then offset against the cost of the IRP-D credits the revenues received from PJM, because the directive is infeasible and, thus, unreasonable and unlawful. Instead, the Commission should modify Rider IRP-D so that it can achieve the result that the Commission seeks.

As noted above, at page 40 of its Opinion and Order, the Commission states that "AEP Ohio should also bid the additional capacity resources associated with Rider IRP-D into PJM's base residual auctions held during the ESP term, with any resulting revenues credited back to customers through the EE/PDR rider." While the goal of reducing the cost to all customers of providing interruptible credits to Rider IRP-D customers, by offsetting against those costs the revenues obtained from the sale of the related capacity resources into PJM is understandable and appropriate, it will not be feasible to do it in the manner that the Opinion and Order seems to contemplate. First, PJM already has conducted the base residual auctions into which such capacity resources may be bid for each of the years that span the three-year term of the ESP III, June 1, 2015, through May 31, 2018. As a result, AEP Ohio will not be able to directly realize revenues from the sale of IRP-D related capacity resources into PJM during the ESP III. In short, because it cannot sell the IRP-D related capacity resources into PJM during the term of the ESP III, AEP Ohio will not be able to use the revenues from such sales to reduce the cost of the IRP-D interruptible credits.[16]

Second, it is highly likely that existing IRP-D customers already have bid their IRP-D related capacity into PJM's base residual auctions for the three delivery years of ESP III, either through curtailment service providers (CSPs) with whom they have entered contracts for that

[16] There will be additional incremental capacity auctions for delivery of additional capacity during the last two of the three delivery years that span the term of ESP III. However, such incremental auctions would not likely provide much revenue from IRP-D resources not already bid into PJM in the base residual auctions for delivery during ESP III and, in any event, would not achieve the Commission's purpose of offsetting all revenues realized from sales of IRP-D interruptible capacity resources against the cost of IRP-D's interruptible credits.

purpose or on an individual basis. Accordingly, due to contractual arrangements already in place, it likely would be infeasible at this point to require customers with IRP-D related capacity resources to allow AEP Ohio to bid those resources into the PJM market and directly recover capacity revenues to use as an offset against IRP-D costs as a condition to obtaining service under Rider IRP-D (even if there was not the additional difficulty resulting from the fact that the base residual auctions for sale of capacity during the ESP term have already been conducted).[17]

However, the Commission can still achieve the purpose of offsetting PJM capacity revenues earned by Rider IRP-D customers against the cost of the interruptible credits that those customers receive through Rider IRP-D, thus mitigating the impact on customers who pay the costs of those credits. It could achieve its purpose by modifying Rider IRP-D in the following manner: First, as a condition of participating in Rider IRP-D, all IRP-D customers receiving service under that tariff could be required to certify to AEP Ohio that they have bid, or will bid in the next auction, their interruptible capacity resources into the PJM capacity market. Next, pursuant to the modified Rider IRP-D, AEP Ohio could be required to offset against, and reduce the amount of, the interruptible credits provided to each IRP-D customer by the gross amount of capacity revenues, which could be calculated based on the weighted average auction clearing price and the amount of any emergency energy payments during events. AEP Ohio would then recover from all customers, through the rider used to recover the cost of the Rider IRP-D interruptible credits (and, as noted elsewhere, AEP Ohio recommends that the EDR be used for that purpose), the net amount of the Rider IRP-D interruptible credits minus the gross amount of revenues realized from the sale of the IRP-D customers' interruptible capacity and emergency energy into the PJM market. In this manner, the Commission could achieve its goal of reducing

[17] AEP Ohio is not recommending that customers who already have bid their IRP-D related capacity into the PJM auctions for the term of ESP III should be disqualified from Rider IRP-D.

the cost to all customers of the Rider IRP-D interruptible credits by the revenues received from the sale of the IRP-D customers' interruptible capability into the PJM market. Further, this approach allows IRIP-D customers to participate in Economic and Ancillary Service DR programs, something that would be difficult to do if the Company bid the customers' capabilities into the auctions. In addition, establishing that customers participating in the Rider IRP-D register with PJM and participate in PJM auctions will eliminate the uncertainty that existed at the end of this ESP term. For example, the first PJM auction for planning year 2018/2019 is fast approaching. The customers would clearly know today to register and participate in that auction and that would not depend upon whether or not Rider IRP-D is extended in the ESP or MRO that will apply beginning June 1, 2018. As such, customers would have the opportunity to maximize the benefit of their demand response capability and auction participation without the concern that their registration could impact whether or not they could participate in Rider IRP-D in the future, if available.

D. The Commission should also confirm that AEP Ohio is entitled to fully recover its costs of providing all interruptible credits required by Rider IRP-D; if the Opinion and Order did intend to create uncertainty regarding the Company's right to recover those costs, it is unreasonable and unlawful and should be corrected on rehearing.

Another aspect regarding IRP-D which AEP Ohio requests clarification or rehearing is the Opinion and Order's directive, at 40, that the Company should continue to "apply" for recovery of the costs associated with the IRP-D through the EE/PDR rider until otherwise ordered by the Commission. AEP Ohio seeks clarification that, by use of the word "apply," the Commission was not in any way leaving open the possibility that AEP Ohio would not be entitled to recover its actual costs of paying the IRP-D interruptible credits (less any revenues obtained by bidding the related interruptible capacity resources into PJM's capacity auctions). Rather, AEP Ohio seeks clarification that, consistent with the Commission's *ESP II* decision, AEP Ohio is entitled to recover its actual costs of providing the IRP-D interruptible credits. *See ESP II* Opinion and Order at 26 (finding it appropriate for AEP Ohio to recover "costs associated with the IRP-D under the EE/PDR rider").

Moreover, the *ESP III* Order itself, at page 84, strongly supports the conclusion that the Company is entitled to recover the actual costs of Rider IRP-D by granting deferral accounting authority for those costs until they are recovered through rates. Such deferral accounting authority is only possible if the underlying deferred expenses are probable of recovery in future rates.

If the Order did intend to leave open a possibility that, after applying for recovery the IRP-D credit costs, recovery would not be assured, AEP Ohio requests rehearing to correct that unreasonable and unlawful result.

IV. The Commission's modification and authorization of the Purchase of Receivables Program and Associated Bad Debt Rider is unreasonable and unlawful.

A. It is unreasonable for the Commission to leave so many merit issues involved in the litigation open for further debate subject to a future proceeding.

The Commission modified and approved AEP's proposal to offer a purchase of receivables program in its territory. The Commission did not issue a decision on many critical aspects of AEP's proposal, such as the administrative fee for costs, payment priority, discount rate parameters, holding the Company harmless to negative impacts, bypassability of the BDR, security deposit criteria, industrial customer eligibility. The Company would presume anything unaddressed defers to the Company's filing but other parties may assume all those matter are delegated to a working group process. It is unreasonable and unworkable to take a fully litigated matter dealing with a voluntary proposal and to delegate so many baseline issues that were litigated in the ESP to a working group. Furthermore, the scope of the MDWG as set forth by the Commission, and as envisioned and proposed by AEP Ohio in Case No. 12-3151-EL-COI, is to define policy and standardization in an effort to further develop the Choice market. Specifically the MDWG is for "streamlining and aiding the development of Ohio's CRES market." *In re Investigation of Ohio's Retail Electric Service Market*, Case No. 12-3151-EL-COI, Finding and Order at 26 (Mar. 26, 2014) ("*Investigation* Finding and Order"). Since the preferred policy of establishing a purchase of receivable programs with some variability between EDUs as necessary has already been set forth, and as the program as offered by AEP Ohio is very similar to what Duke has already implemented, there is no value in rehashing opposing positions again through the MDWG.

The Commission was also unable to reach a consensus recently in its competitive industry issues review involving input all industry stakeholders, including the Staff, OCC, EDUs, and CRES providers and Associations. *See id.* In fact, in this PUCO Market Study, the Commission rejected the Staff proposal for a requirement that POR implementation plans be filed by each EDU. The Commission left it to each individual EDU to determine a program that made sense for its territory and propose that program in a distribution rate case or electric security plan proceeding. *Id.* at 21.

AEP Ohio included a POR program structure it was willing to implement in its ESP in this docket. The implementation of a POR program was never a requirement. There is no rule or law requiring such a service be provided to CRES providers in Ohio. A POR program is a service that may be authorized but not necessarily implemented if the regulated utility is not in agreement with the parameters. Ohio Power will explore the process of the current and any future modifications and then decide if it will implement the program.

The Commission's discussion of the positions in the present case identifies at least 11 parties' points of view on the subject. The Commission's modifications will raise costs, increase risk of recovery for the Company, decrease operational efficiencies, and potentially increase customer frustration with inconsistent billing year to year. There is also the concern that there are critical aspects still undefined and left to debate amongst the group that litigated issues in this case and the participants in the market study that could not agree previously.

The nature of the discussions is also unreasonable because of the position it puts parties in to discuss litigation positions without any settlement type protection attached to the discussions. Open deliberation and idea development is chilled by the structure of the public working group. There is little incentive to develop theories in the working group when such conversations and work product could be used against a party in a subsequent Commission proceeding determining the path forward.

The Company respectfully seeks rehearing on this issue for the Commission to address these unreasonable aspects of the Order. The Commission can remedy these issues by implementing the POR plan outlined by the Company and as presented by Company witnesses at hearing. Implementation of the Company plan will still benefit from a working group concept as suggested by the Commission. The difference being that it will be discussing ways to implement the defined program versus generating key components of the program. To be reasonable and recognize the record in this case discussing the benefit to the industry, the Commission should ensure that basic consistency with the gas industry and Duke to not have a discount rate and use the bad debt rider should be approved as proposed by the Company for CRES providers entering the market. If the Commission is unwilling to fix the inconsistency of the modified program with the other POR programs in Ohio, it should at a minimum make another global finding that Ohio Power should be held harmless to any cost impact of the program. The Company presented the program as voluntary and that it was important that it be implemented cost neutral to the

Company. The Commission Staff agreed with this point on cross-examination. Specifically, when discussing the Company's POR proposal, Staff witness Donlon agreed that the utility should be held harmless to the costs related to offering the POR program, the program it is offering at its discretion to benefit others. (Tr. IX at 1268.) At a minimum the Commission should grant rehearing to ensure that the conversations and discussions of parties in the working group not be used against a party as an official position in the future. The Commission should also limit discussion of any position taken by a party in the working group to the representations made by that individual party and not assertions or summaries by other parties.

B. It is unreasonable for the Commission to include a CRES providers early termination fees as a commodity-related charge.

One of the findings the Commission made relating to the structure of the POR program is that only commodity-related charges may be included in the program. Opinion and Order at 80. While the Company agrees with this finding in principal, the Commission's finding is undefined leaving an issue in the docket still unaddressed. The Company proposed this same criteria but pointed out that the "commodity-related" reference dealt solely with the cost of the generation commodity and not for items like early termination or programs offered by CRES providers beyond the simple provision of the generation source. (AEP Ohio Ex. 11, Direct Test. of Stacey D. Gabbard, at 8.)

The Commission did not modify this point, but the Company respectfully seeks rehearing on this issue for the Commission to clarify that "commodity-related charges" means only the charges tied to the actual cost of generation and not the other CRES charges, including but not limited to early termination charges for customers and the charges for other services provided by the CRES provider (e.g., weatherization, appliance control, energy audits, etc.). This clarification will make the Commission direction clear and concise and ensure that the proper costs are included in the program.

C. It is unreasonable and unlawful for the Commission to allow a CRES provider to pick and choose its customers that the regulated utility will be required to acquire their receivables.

Another of the findings the Commission made relating to the structure of the POR program is the finding that "participation in the POR program by CRES providers that elect consolidated billing must not be mandatory." The Company reads this language to mean that each CRES provider can decide on its own whether they will participate in the program but if they do it is for all of its eligible customers on consolidated billing. But the finding needs clarification to the extent that a party may read this to mean that a single CRES provider could pick and choose which of its eligible customers to include and not include in the POR program.

If a CRES provider is allowed to pick and choose which customers to place into the EDU's POR program, then the Order provided an unreasonable and unlawful finding. The rationale behind the POR is to streamline the collection process and simplify the payment options process for all shopping customers, thus increasing over-all customer satisfaction. As indicated in the record in this case, if implemented as modified with the option to pick and choose customers, then CRES providers will likely place all high to moderate risk customers in POR and retain timely paying customers. (AEP Ohio Ex. 11, Direct Test. of Stacey D. Gabbard, at 7.) This will allow the CRES provider to avoid the discount and remove a portion of shopping customers from the benefits of Average Monthly Payment and Budget payment options, resulting in increased customer frustration with Choice. A Commission interpretation that allows a CRES to pick and choose the customers would run afoul of R.C. 4928.02(H) and the legal standard against subsidies. The Company proposal was applied evenly across the board, but the Commission modification allows a CRES provider to jettison its riskiest receivables risk to the regulated entity while retaining the low risk receivable accounts. The modification allows the CRES to use the POR program as a subsidy using the regulated industry to bolster the unregulated industry, in violation of R.C. 4928.02(H).

The Company respectfully seeks rehearing on this issue for the Commission to require all CRES on consolidated billing to participate in POR. In the alternative, the Commission should clarify that a CRES must be all-in or all-out with its customer base and not pick and choose which customers to enroll. If the Commission takes this alternative approach it should also require a five-year stay on the program as discussed below in the next rehearing ground.

D. It is unreasonable and unlawful for the Commission to modify the AEP proposed POR structure to provide CRES providers on consolidated billing the yearly option to participate.

Even assuming that the Commission modifications require all consolidated billing customers of a CRES to participate in the POR program, the modification to allow some providers in and some out is unreasonable because of the expense and increase in the scope of implementation. It is too expensive and cumbersome to implement and maintain multiple programs for CRES on consolidated billing. Allowing some CRES accounts in and others out will be costly to program and require the Company to maintain two processes in AEP Ohio's EDI and Customer Information System. (AEP Ohio Ex. 11, Direct Test. of Stacey D. Gabbard, at 6-7.) The modification means that the Company will offer different payment options programs for shopping customers based upon CRES. What would likely manifest is that CRES suppliers whose customers have good payment history will not participate in the POR program, and those customers will be discriminated against in terms of less appealing payment options available to them, where customers in the POR program will have access to Average Monthly Payment and Budget programs.[18] (*Id.* at 15.)

The Commission modification not making the POR program uniformly applied in the territory also has the unintended consequence of increasing costs and the structure of the computer systems and call centers. Under the Commission's version of POR, AEP Ohio will also have to maintain two scripting and customer service support processes. Mr. Gabbard already testified in the regard that this would be inefficient and would not provide the customer with the best experience. (*Id.* at 7.) There is no indication where the recovery of this cost will come from to ensure it is done, or acknowledgment that decreased efficiencies resulting in increased call times will impact call center metrics.

The Company respectfully seeks rehearing on this issue asking the Commission to make the AEP POR program mandatory for all CRES providers using consolidated billing as proposed by the Company. Alternatively, the Commission could require CRES providers to participate on a 5-year basis. A five year usage requirement would provide recovery for programming, help develop the mechanisms of the POR program and ensure consistency for customers. A third option can be considered due to incremental program costs that will be incurred beyond what the Company proposed. A consolidated billing charge for CRES providers that choose not to participate in the POR program could be applied to recover costs to maintain additional processes and systems for CRES providers that choose not to participate in a standard POR program. Finally, regardless of the other issues, the Commission must declare that it is holding AEP harmless to the cost impact of the final structure modifying the AEP proposed option.

[18] The argument applies equally to the prior argument concerning an individual CRES provider that can pick and choose the customers to place on the POR program.

E. It is unreasonable and unlawful for the Commission to forego creation of a mechanism for cost recovery of the implementation and administrative costs of the modified program.

The record indicates that implementation of the AEP proposed POR program comes at a significant cost. The Commission Order recognized the AEP testimony that the fully automated POR program, as proposed by AEP, would cost $1.5 million with an ongoing O&M requirement of $207,600 annually. Opinion and Order at 71. The AEP proposed program was a simpler and streamlined program compared to the program after the Commission's modifications, which create a dual system. Any system implemented under the Commission's modification will have increased costs beyond those enumerated in the record. The Commission did not deny or modify the creation of an administrative fee as proposed by AEP. However, the $0.77 rate will no longer cover the increased costs of the program modified by the Commission. There is also great uncertainty concerning what other costs could be developed as the working group, made up of mostly CRES providers, considers implementation. It is unclear if that increased fee amount is a matter for the working group to determine or a compliance filing for the Company at a later date. Conversely, if the administrative fee was not approved by the Commission, then the finding unreasonably and unlawfully requires the regulated EDU to subsidize bill collection of the competitive entities in violation of R.C. 4928.02(H).

The Company respectfully seeks rehearing on this issue asking the Commission to implement the POR program proposed by the Company with full recovery through the bad debt rider, as it is done in the Duke electric jurisdiction and the gas industry in Ohio. Regardless of that finding, the Commission should clarify that AEP will be held harmless to all administrative and implementation costs. This affirmative statement is necessary to control the debate amongst litigants to this case reasserting their litigation positions in the working group. In addition the Commission should validate the administrative fee creation for all CRES providers until the cost of implementation is recovered. The POR is being created for the benefit of CRES providers, customers and the development of the market. The regulated utility is just the vehicle for this outcome and should not bear any risk. The costs of creating that system should be borne by those benefiting parties. Such a finding should ensure productive and cost conscious discussions in the working group.

F. It is unreasonable for the Commission to require plans for supplier consolidated billing and switching provisions in the August 31, 2015 implementation filing.

The Commission determined that the existing working group could develop an implementation plan but also discussed other issues that could be discussed. It is unreasonable to find that all items related to CRES supplier issues can be incorporated in an August 15, 2015 plan. The Commission discussed some switching provisions and referenced the existing group. Opinion and Order at 81. Mixing these issues with the development of an implementation plan for the authority in this Order related to POR only serves to weigh down the efficiency of developing a plan and instead leaves the process at risk of discussing the CRES preferred issue of the day.

The Company respectfully seeks rehearing on this issue asking the Commission to clarify that its dicta on non-implementation issues was not intended to be included in the plan for filing on August 31, 2015. The sheer number of parties and differing interests requires a focused goal for the working group meetings. Absent a clear goal the different parties can focus on preferred issues versus the assigned issue by the Commission. The more global issues can be discussed at any time by the plan developed for August 15, 2015 should focus narrowly on the rules of the road for implementation of a POR program in AEP's territory.

G. It is unreasonable and unlawful for the Commission to set up a bad debt rider to recover generation related costs above the amount already being recovered through base rates, because the record does not contain the amount in base rates related to CRES Receivables and generation-related uncollectible expense.

The Commission denied the Company's proposal to recover all bad debt, offset by the amount included in rate base, through the bad debt rider. Opinion and Order at 81-82. The $12.2 million baseline prepared by the Company incorporates all the elements of the bill (Transmission, Distribution, and Generation charges). (AEP Ohio Ex. 11, Direct Test. of Stacey D. Gabbard, at 9.) However, the Commission modified the Company proposal to only allow recovery of CRES Receivables and generation-related uncollectible expense (i.e., only the generation portion of the bill). It is unreasonable to compare the generation portion of the bill to the entire $12.2 million baseline from the 2010 base rate case that includes generation, transmission and distribution bad debt.

The Commission modification to take the component of bad debt related to generation charges and compare that to the entire bill that includes generation, transmission and distribution bad debt from the last base rate case is unreasonable and unlawful. This is a classic apples to oranges comparison. The Commission found that it could not apply the total amount of bad debt in the Bad Debt Rider because that would somehow allow the Company to adjust the amount of debt already included in base rates. Opinion and Order at 81. However, that is exactly what the Commission has done because its limitation to the generation portion of the bill did not modify the comparison to the $12.2 million amount included in base rates negates the test year snapshot of distribution and transmission charges that are already included in rates. The Company proposal was to compare apples to apples and use the $12.2 million baseline already in rates and compare that to all bad debt now so that it is an accurate comparison. If the amount is higher, then only the incremental amount will be recovered. If the amount is lower, then a credit would be provided to customers. This symmetrical application is the only reasonable way to apply this rider and does not disturb the findings in the distribution rate case. The Commission's modification unreasonably denies the Company rates approved in the last base rate case in violation of the rates established under R.C. 4909.15 without a R.C. 4909.26 complaint or investigation to change the distribution rate. The impact of the Commission's modification would be to lower the amount of recovery approved in base rates without any opportunity or record justifying the decrease. The offsetting of one component of the bad debt compared to the entire class of unrecovered expenses in the bad debt portion of rates is an unlawful act due to its application.

The Company respectfully seeks rehearing on this issue asking the Commission to institute the bad debt rider as proposed by the Company to mirror the process used for CRES in the Duke electric territory and for gas companies in Ohio. However, if the Commission is unwilling to provide a consistent CRES playing field between jurisdictions on POR, then it should grant rehearing to allow the Company to reflect the comparable baseline level of generation related bad debt included in the bad debt baseline used for the 2012 base rate case. This subset of the last base rate case amount is the proper baseline to use under the modified theory enumerated by the Commission, not the $12.2 million. Absent a grant of rehearing to consider the new evidence, there is nothing in the record to support the baseline to effectuate the bad debt rider because the $12.2 million figure is not applicable. Once the appropriate baseline is established, then the Company will then be able to apply the bad debt rider using comparable figures to determine if there is a charge or credit. Absent correction the modification requiring the calculation will ensure the amount appropriated in the R.C. 4909 rate case is not recovered in the absence of a R.C. 4905.26 complaint case change or subsequent rate case. This is different than the Company proposal because the Company sought to offset the amount in rates with current like-for-like costs. The modification improperly changes the amount approved in rates using factors and figures that are not comparable.

H. It is unreasonable for the Commission to order AEP to implement a Commission modified POR program that will not allow it to disconnect for non-payment of expenses the regulated utility is required to purchase.

The Commission unreasonably denied the ability to disconnect customers for CRES charges. Opinion and Order at 82. One of the basic justifications for implementation of POR programs by regulated utilities in deregulated markets is the advantage of the regulated utility to disconnect for nonpayment. The disconnection for nonpayment of receivables is one of the reasons that purchase of receivables programs have become a cornerstone for many of the Northeast and Midwest markets because it simplifies the process. (Tr. III at 780 (AEP Ohio witness Gabbard).) The right to disconnect is the difference between CRES collection and the regulated entity overseeing collection, because it provides the incentive for the customer to pay its arrearages if the customer is subject to disconnection. (Tr. XI at 2654 (RESA witness Bennett).) Out of an abundance of caution, AEP sought a waiver of O.A.C. 4901:1-18-10(D) to ensure it would not run afoul of Commission rules. However, the Commission denied the waiver concerned that it could contradict R.C. 4928.10(D)(3) that requires rules to prevent the blocking of access to non-competitive service when a customer is delinquent in payments to the utility or competitive provider for nonpayment of a competitive retail electric service. Opinion and Order at 82. The Commission finding is curious as it currently allows for disconnection of service for nonpayment of CRES receivables in both the gas industry and in the electric industry.

Perhaps the Commission ruling is merely a matter of semantics and the explanation for inconsistency with other regulated entities could be clarified to address the unreasonable result of having the increased risk for the regulated EDU to purchase the receivables and not have the ability to disconnect customers as a tool to ensure timely payment and prevent excessive unpaid bills. If the Commission clarified that the CRES receivables become a regulated debt of the EDU and not a cost of a competitive retail electric service, as other surrounding deregulated markets do, then the waiver would not be needed and the utility could disconnect for non-payment of its regulated cost from the POR program. This rationale makes sense as the EDU is not offering the CRES providers competitive service, but instead taking over an amount due under a regulated order from the Commission as part of an ESP to authorize a POR program. Furthermore, this is why the Company requests limitation of purchased receivables to generation-related charges, so that other CRES service-related charges beyond the provision of generation would not be grounds for disconnection.

The Company seeks rehearing to clarify this point on the ability to disconnect customers for non-payment of the costs forced upon the regulated utility if a POR program is implemented. Without such a clarification the finding is unreasonable as there is no clear distinction between the authorization for other POR programs to disconnect for receivables and the AEP authorized program that would not allow disconnection. Thus, the Commission should either grant the requested waiver on rehearing or clarify that waiver is not needed for the reasons explained above.

I. It is unreasonable that the Commission creates a greater liability on the utility by denying the right to disconnect for receivables but does not provide an industry-wide applied practice of a late payment fee to encourage timely payment.

The Commission unreasonably denied the Company's request to encourage timely payment of customer bills through the implementation of a late payment charge. Opinion and Order at 81-82. Most Ohio utilities already utilize 1.5% late payment charge for residential customers. (AEP Ohio Ex. 3, Direct Test. of Gary Spitznogle, at 11.) The denial is even more unreasonable in light of the fact that AEP is now apparently barred from disconnecting service for the nonpayment of CRES receivables assigned as part of the POR program.

The fact that a late payment charge could be established in a rate case, Opinion and Order at 82, is not a reasonable reason to not weigh the merits in this case. The Commission even appears to be dissuading the Company from filing a rate case in the near future in this case. Opinion and Order at 95. Regardless, timely payment and collections were issues in this case and the Company provided a reasonable proposal to address those issues. It is unreasonable to create a system where suppliers can put their riskiest customers on the back of the regulated utility and keep the secure customers but not take the opportunity to encourage timely payment behavior. As such the Company respectfully requests the Commission grant rehearing to modify its Order to allow for the late payment charge as it has for Duke and other providers in Ohio.

V. The Commission's denial of AEP Ohio's proposed NERC Compliance and Cybersecurity Rider was unreasonable and unlawful.

In its Opinion and Order, the Commission denied AEP Ohio's proposed NERC Compliance and Cybersecurity Rider (NCCR). Opinion and Order at 62. Although it confirmed that it "believes that NERC compliance and cybersecurity matters are of the utmost importance for Ohio's customers and customer information, as well as for the security of the electric grid and electric distribution utility facilities," and recognized that "it is important that AEP Ohio take the necessary action to secure the electric grid and react quickly to protect the electric distribution system for the benefit of all consumers and the economic stability of our state," the Commission nonetheless declined to establish the requested placeholder rider. *Id.* (emphasis added). That decision was unreasonable in several respects.

The Commission justified its denial of AEP Ohio's NCCR on the grounds that the magnitude and allocation of NERC compliance and cybersecurity costs are not presently known.

Id. But the Company's future NERC compliance and cybersecurity costs are no less speculative than the costs to be included in other zero dollar placeholder riders the Commission has approved in other cases, including this one. Any costs sought to be recovered through the rider would be fully reviewed in future proceedings, and their prudency and appropriateness as distribution costs could be confirmed there. (*See* AEP Ohio Br. at 101-102.) Commission precedent supports the approval of a zero dollar placeholder rider like the proposed NCCR, as the Commission itself recognized elsewhere in its Opinion and Order. Opinion and Order at 25 (noting that "the Commission has, on prior occasions, approved a zero placeholder rider within an ESP" and citing other placeholder riders previously approved in AEP Ohio's, Duke's, and FirstEnergy's prior ESPs). Indeed, in this case alone, the Commission approved three other placeholder riders, the recovery of costs through which will be subject to future proceedings. *Id.* at 25 (PPA rider), 81 (BDR), 86-87 (pilot demand response rider). The Commission should act consistently with both its past precedent and its present decision and grant rehearing to approve AEP Ohio's placeholder NCCR. In addition, in the Company's prior *ESP II* proceeding the Commission approved the Company's Storm Damage Recovery (SDR) and Peak Demand Reduction (PDR) riders, each of which was established at a zero dollar level. The amounts of costs that would be eligible for recovery through the SDR and PDR riders were not known at the time those riders were approved. Subsequently, the Company did incur costs of the types that the SDR and PDR riders were intended to recover, those costs were subjected to the Commission's and interested parties' review in proceedings conducted for that purpose, and after that review recovery of the eligible costs through those riders was allowed. The costs that AEP Ohio has proposed for recovery in this proceeding through the NCCR are no more speculative than those ultimately recovered through the SDR and PDR riders, and are certainly no less important to incur than the costs recovered through those riders.

Moreover, even if it "is not evident that AEP Ohio * * * will incur costs for compliance with NERC standards," it is clear that the Company will incur cybersecurity costs to address ever-increasing cybersecurity risk. Opinion and Order at 62. (*See also* AEP Ohio Br. at 102.) The Company should be permitted to recover those costs, many of which would be incurred as AEP Ohio is required to "react quickly to protect the electric distribution system," Opinion and Order at 62, in a timely fashion as they are incurred. The suggestion that the Company recover those costs through a costly and time consuming distribution rate case is incompatible with the urgent nature of the activities causing those costs. Allowing the Company to defer these costs and seek their recovery through the NCCR best aligns the Company's treatment of cybersecurity issues with their urgency and importance to the Commission. It is therefore unreasonable and unlawful for the Commission to, on the one hand, emphasize the urgency and importance of responding to cybersecurity threats, while on the other hand suggesting that the Company delay recovery of its response costs until it files a distribution rate case. For this reason too, the Commission should grant rehearing and approve the NCCR.

Finally, if the Commission declines to grant rehearing and approve the NCCR as the Company proposed it, AEP Ohio respectfully requests that the Commission grant rehearing and give the Company accounting authority to create a deferral for NERC compliance and cybersecurity costs incurred during the ESP III term, the recovery of which the Company can seek Commission approval in a future proceeding.

If the Commission believes that cybersecurity is a serious issue it has an opportunity to show that in this case where the opportunity to create a special mechanism in case it is needed.

The Commission will ultimately control whether or not costs are allowed to be included in the rider but will not have the ability to create such a rider under this statute at some unknown future date. The Company is committed to ensuring cyber security and seeks a partner in the Commission in committing to that with approval of this rider. The Commission should provide the Company with a recovery mechanism that reflects the critical importance of investments in NERC compliance and cybersecurity matters that this Commission acknowledged.

VI. On rehearing, the Commission should correct the Opinion and Order's determination regarding the MRO Test by finding that the modified ESP provides $53,060,000 of quantifiable benefits that would not be possible under an MRO.

Upon consideration of the Company's ESP, in its entirety, the Commission found that the ESP, as modified, is more favorable in the aggregate than the expected results of a market rate offer (MRO) filed under R.C. 4928.142. Opinion and Order at 94-95. In particular, the Commission found that by voluntarily extending the Residential Distribution Credit Rider (RDCR) for the three year term of ESP III, the Company's ESP provides a quantifiable benefit in the amount of $14,688,000 annually or $44,064,000 over its term.[19]

The Commission made two modifications to the Company's proposed ESP that together add an additional $9 million of costs to the Company and quantitative benefits the ESP. On rehearing, the Commission should account for those benefits in the MRO test and clarify that the quantitative benefits from the modified ESP total $53,064,000 over its three-year term. First, the Commission noted that the annual $1 million funding of the Neighbor-to-Neighbor program, which was an additional component of the original RDCR mechanism, is an essential element of that credit mechanism that furthers state policy. *Id.* at 65. Consequently, the Commission

[19] The Commission also found that the ESP provides numerous additional benefits that, although less readily quantifiable than the benefits of the RDCR, nevertheless furnish substantial value. Opinion and Order at 95.

modified the Company's RDCR proposal to continue to include $1 million annually to fund the Neighbor-to-Neighbor bill payment assistance program to support at-risk and low-income customers in the Company's service area. That modification added $3 million of quantitative benefits to the Company's ESP.

Second, the Commission directed the Company to continue the Ohio Growth Fund by contributing to it $2 million dollars per year over the term of the modified ESP. *Id.* at 69-70. This modification provides an additional quantifiable benefit of $6 million during the course of ESP III.

These two modifications provide additional quantifiable benefits of $9 million in total over the three year term of ESP III. When added to the $44,060,000 of quantifiable benefits already provided by the extension of the RDCR, the total quantifiable benefits of the modified ESP increase to $53,060,000. On rehearing, the Commission should include in the MRO Test analysis the additional $9 million of quantifiable benefits that the modified ESP provides through the Neighbor-to-Neighbor program and Ohio Growth Fund during the ESP's term. The Commission should find that the modified ESP provides $53,060,000 of quantifiable benefits that would not be possible under an MRO.

CONCLUSION

For the foregoing reasons, the Commission should grant rehearing and should reverse, modify, and/or clarify its February 25, 2015 Opinion and Order as set forth above.

Respectfully submitted,

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On behalf of Ohio Power Company

Attachment A

Summary of Capital Spend Required to keep Revenue Cap Flat for 2015

Estimated Gross Plant as of December 2014	$	4,066,174,623.00
Remove gridSMART Gross Plant	$	26,256,004.90
Remove Vegetation Management Gross Plant	$	32,773,912.69
Remove Plant Held for Future Use	$	18,085.00
DIR Gross Plant in ServiceDecember 2014 Est	$	4,007,126,620.41
Depreciation Rate		3.68%
Capital Spend at Depreciation Levels	$	147,462,259.63

* December Amounts are estimated Based on the September 2014 DIR as Filed in Case No. 14-1696-EL-RDR Increased by a Revenue Requirement of $2.5M per Month

Illustration of DIR Calculation With Plant in Service Capital Spend equal to Depreciation $(147M)

Line		Return	Depreciation	Property Tax	Total
1	Distribution Plant as of 8/31/2010	$ 3,345,925,000	$ 3,345,925,000	$ 3,345,925,000	
2	Accumulated Depreciation as of 8/31/2010	$ 1,253,173,000	$ -	$ 1,253,173,000	
3=1-2	Net Distribution Plant	$ 2,092,752,000	$ 3,345,925,000	$ 2,092,752,000	
4					
5	Estimated December 2015 Distribution Plant	$ 4,213,174,623	$ 4,213,174,623	$ 4,213,174,623	
6	Estimated Accumulated Depreciation December 2015	$ 1,617,141,909		$ 1,617,141,909	
7=5-6	Net Distribution Plant	$ 2,596,032,713	$ 4,213,174,623	$ 2,596,032,713	
8					
9=7-3	Change in Distribution Net Plant	$ 503,280,713	$ 867,249,623	$ 503,280,713	
10					
11	gridSMART II Net Plant Adjustment (Recovered through GS Rider)	$ 20,215,097	$ 26,256,005	$ 20,215,097	
12					
13	Incremental Veg Mgmt Net Plant Adjustment (Recovered through Rider)	$ 29,406,854	$ 32,773,913	$ 29,406,854	
14					
15	Theoretical Reserve Per Order and Plant Held For Future Use	$ 18,085	$ -	$ 139,632,000	
16					
17	Incremental ADIT Offset	$ 222,640,025	$ -	$ -	
18					
19=9-11-13-15-17	Adjusted Change in Distribution Plant	$ 231,000,653	$ 808,219,705	$ 314,026,763	
20					
21	Carrying Charge Rate	10.54%	3.68%	5.66%	19.88%
22					
23=19*21	Initial Rider Revenue	$ 24,347,469	$ 29,742,485	$ 17,773,915	$ 71,863,869
24					
25	Revenue Offset Provided in Distribution Stipulation				$ 62,344,000
26					
27=23+25	Revised Rider Revenue				$ 134,207,869
28					
29	Gross Up Factor (CAT and Assessment Fees)				100.26%
30					

Plant in Service Increased to reflect Spend at Depreciation levels, $146M
Theoretical Reserve Included per Opinion and Order 13-2385-EL-SSO
Carrying Charge Rate Changed per Opinion and Order 13-2385-EL-SSO

Illustration of DIR Calculation With September 2014 Plant in Service Filed in Case No. 14-1696-EL-RDR

Line		Return	Depreciation	Property Tax	Total
1	Distribution Plant as of 8/31/2010	$ 3,345,925,000	$ 3,345,925,000	$ 3,345,925,000	
2	Accumulated Depreciation as of 8/31/2010	$ 1,253,173,000	$ -	$ 1,253,173,000	
3=1-2	Net Distribution Plant	$ 2,092,752,000	$ 3,345,925,000	$ 2,092,752,000	
4					
5	September Distribution Plant Less Plant Held for Future Use	$ 3,991,453,253	$ 3,991,453,253	$ 3,991,453,253	
6	Accumulated Depreciation September 2014	$ 1,428,080,513	$ -	$ 1,428,080,513	
7=5-6	Net Distribution Plant	$ 2,563,372,740	$ 3,991,453,253	$ 2,563,372,740	
8					
9=7-3	Change in Distribution Net Plant	$ 470,620,740	$ 645,528,253	$ 470,620,740	
10					
11	gridSMART I Net Plant Adjustment (Recovered through GS Rider)	$ 20,215,097	$ 26,256,005	$ 20,215,097	
12					
13	Incremental Veg Mgmt Net Plant Adjustment (Recovered through Rider)	$ 29,406,854	$ 32,773,913	$ 29,406,854	
14					
15	Theoretical Reserve Per Order and Plant Held For Future Use	$ 18,085	$ -	$ 104,724,000	
16					
17	Incremental ADIT Offset	$ 208,240,025	$ -	$ -	
18					
19=9-11-13-15-17	Adjusted Change in Distribution Plant	$ 212,740,679	$ 586,498,335	$ 316,274,789	
20					
21	Carrying Charge Rate	10.54%	3.68%	5.66%	19.88%
22					
23=19*21	Initial Rider Revenue	$ 22,422,868	$ 21,583,139	$ 17,901,153	$ 61,907,159
24					
25	Revenue Offset Provided in Distribution Stipulation				$ 62,344,000
26					
27=23+25	Revised Rider Revenue				$ 124,251,159
28					
29	Gross Up Factor (CAT and Assessment Fees)				100.26%
30					

September 2014 Plant filed in Case No. 14-1696-EL-RDR
Theoretical Reserve Included per Opinion and Order 13-2385-EL-SSO
Carrying Charge Rate Changed per Opinion and Order 13-2385-EL-SSO

Illustration of DIR Calculation With Estimated December 2014 Plant in Service

Line		Return	Depreciation	Property Tax	Total
1	Distribution Plant as of 8/31/2010	$ 3,345,925,000	$ 3,345,925,000	$ 3,345,925,000	
2	Accumulated Depreciation as of 8/31/2010	$ 1,253,173,000	$ -	$ 1,253,173,000	
3=1-2	Net Distribution Plant	$ 2,092,752,000	$ 3,345,925,000	$ 2,092,752,000	
4					
5	Estimated December 2014 Distribution Plant	$ 4,066,174,623	$ 4,066,174,623	$ 4,066,174,623	
6	Estimated Accumulated Depreciation December 2014	$ 1,464,801,883		$ 1,464,801,883	
7=5-6	Net Distribution Plant	$ 2,601,372,740	$ 4,066,174,623	$ 2,601,372,740	
8					
9=7-3	Change in Distribution Net Plant	$ 508,620,740	$ 720,249,623	$ 508,620,740	
10					
11	gridSMART II Net Plant Adjustment (Recovered through GS Rider)	$ 20,215,097	$ 26,256,005	$ 20,215,097	
12					
13	Incremental Veg Mgmt Net Plant Adjustment (Recovered through Rider)	$ 29,406,854	$ 32,773,913	$ 29,406,854	
14					
15	Theoretical Reserve Per Order and Plant Held For Future Use	$ 18,085	$ -	$ 104,724,000	
16					
17	Incremental ADIT Offset	$ 208,240,025	$ -	$ -	
18					
19=9-11-13-15-17	Adjusted Change in Distribution Plant	$ 250,740,679	$ 661,219,705	$ 354,274,789	
20					
21	Carrying Charge Rate	10.54%	3.68%	5.66%	19.88%
22					
23=19*21	Initial Rider Revenue	$ 26,428,068	$ 24,332,885	$ 20,051,953	$ 70,812,906
24					
25	Revenue Offset Provided in Distribution Stipulation				$ 62,344,000
26					
27=23+25	Revised Rider Revenue				$ 133,156,906
28					
29	Gross Up Factor (CAT and Assessment Fees)				100.26%
30					

Estimated December Plant -September 2014 Plant filed in Case No. 14-1696-EL-RDR increased by approximately $2 per month
Theoretical Reserve Included per Opinion and Order 13-2385-EL-SSO
Carrying Charge Rate Changed per Opinion and Order 13-2385-EL-SSO

Illustration of DIR Calculation with Spend at Levels at 2015 DIR Plan Filed in Case No. 14-2275-EL-UNC

Line		Return	Depreciation	Property Tax	Total
1	Distribution Plant as of 8/31/2010	$ 3,345,925,000	$ 3,345,925,000	$ 3,345,925,000	
2	Accumulated Depreciation as of 8/31/2010	$ 1,253,173,000	$ -	$ 1,253,173,000	
3=1-2	Net Distribution Plant	$ 2,092,752,000	$ 3,345,925,000	$ 2,092,752,000	
4					
5	Estimated December 2015 Distribution Plant	$ 4,296,574,623	$ 4,296,574,623	$ 4,296,574,623	
6	Estimated Accumulated Depreciation December 2015	$ 1,618,676,469		$ 1,618,676,469	
7=5-6	Net Distribution Plant	$ 2,677,898,153	$ 4,296,574,623	$ 2,677,898,153	
8					
9=7-3	Change in Distribution Net Plant	$ 585,146,153	$ 950,649,623	$ 585,146,153	
10					
11	gridSMART II Net Plant Adjustment (Recovered through GS Rider)	$ 20,215,097	$ 26,256,005	$ 20,215,097	
12					
13	Incremental Veg Mgmt Net Plant Adjustment (Recovered through Rider)	$ 29,406,854	$ 32,773,913	$ 29,406,854	
14					
15	Theoretical Reserve Per Order and Plant Held For Future Use	$ 18,085	$ -	$ 139,632,000	
16					
17	Incremental ADIT Offset	$ 222,640,025	$ -	$ -	
18					
19=9-11-13-15-17	Adjusted Change in Distribution Plant	$ 312,866,093	$ 891,619,705	$ 395,892,203	
20					
21	Carrying Charge Rate	10.54%	3.68%	5.66%	19.88%
22					
23=19*21	Initial Rider Revenue	$ 32,976,086	$ 32,811,605	$ 22,407,499	$ 88,195,190
24					
25	Revenue Offset Provided in Distribution Stipulation				$ 62,344,000
26					
27=23+25	Revised Rider Revenue				$ 150,539,190
28					
29	Gross Up Factor (CAT and Assessment Fees)				100.26%
30					

Plant in Service Increased to reflect Spend at 2015 DIR Plan equivalent of $192M as filed in Case No. 14-2275-EL-UNC
Theoretical Reserve Included per Opinion and Order 13-2385-EL-SSO
Carrying Charge Rate Changed per Opinion and Order 13-2385-EL-SSO

CERTIFICATE OF SERVICE

I hereby certify that a copy of *Ohio Power Company's Application for Rehearing* was served upon counsel for all other parties of record in this case, on this 27th day of March, 2015.

/s/ Steven T. Nourse
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