BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE LONG-TERM FORECAST REPORT OF OHIO POWER COMPANY AND RELATED MATTERS.	)))	**CASE NO. 18-501-EL-FOR**
IN THE MATTER OF THE APPLICATION SEEKING APPROVAL OF OHIO POWER COMPANY'S PROPOSAL TO ENTER INTO RENEWABLE ENERGY PURCHASE AGREEMENTS FOR INCLUSION IN THE RENEWABLE GENERATION RIDER.	))))))))	**CASE NO. 18-1392-EL-RDR**
IN THE MATTER OF THE APPLICATION OF OHIO POWER COMPANY TO AMEND ITS TARIFFS.	))))	**CASE NO. 18-1393-EL-ATA**

INITIAL BRIEF OF <u>INTERVENOR OHIO COAL ASSOCIATION</u>

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I. <u>INTRODUCTION</u>

On April 16, 2018, AEP Ohio filed its 2018 Long Term Forecast Report ("LTFR") in Case No. 18-501-EL-FOR. On September 19, 2018, AEP Ohio filed an Amendment to the LTFR. The purpose of the Amendment was to demonstrate a claimed "need" for at least 900 MW of renewable energy projects in Ohio - 500 MW nameplate capacity of wind energy projects and 400 MW nameplate capacity of solar projects. These projects were subject to Commission approval pursuant to R.C. 4928.143(B)(2)(c) and cost recovery through a PPA Rider. AEP Ohio expressly acknowledged in the Amendment that a statutory predicate for a nonbypassable surcharge for the life of the facility under R.C. 4928.143(B)(2)(c) is that the Commission "first determines in the proceeding that there is a need for the facility *based on resource planning projections* submitted by the electric distribution utility." Amendment at p. 2 (quoting R.C. 4928.143(B)(2)(c)).

On September 27, 2018, AEP Ohio filed an Application (PUCO Case No. 18-1392-EL-RDR and 18-1393-EL-ATA) seeking Commission approval of a proposal to enter into two Renewable Energy Purchase Agreements for inclusion in the RGR - a proposed 300 MW solar facility (Highland Solar or "Hecate") and a proposed 100 MW solar facility (Willowbrook). AEP Ohio seeks a Commission order finding these REPAs are reasonable and prudent and seeks recovery through the RGR of a nonbypassable charge under R.C. 4928.143(B)(2)(c) (inclusive of REPA costs and debt equivalency costs) for the life of the facility.

The Commission Staff filed a Motion For Hearing in Case No. 18-501-EL-FOR. AEP Ohio opposed Staff's motion but alternatively argued for consolidation of Case No. 18-501-EL-FOR with Case Nos. 18-1392-EL-RDR and 18-1393-EL-ATA.

On October 22, 2018, the Attorney Examiner issued an Entry granting the Staff's request for hearing and granting AEP-Ohio's motion to consolidate the cases. Entry at 11, ⁋32 (Oct. 22, 2018) However, the Attorney Examiner directed the bifurcation of these cases into two phases - the "need" for the facility heard first as a distinct issue under R.C. 4928.143(B)(2)(c) with cost recovery through the nonbypassable surcharge under R.C. 4928.143(B)(2)(c) to be heard in a subsequent phase. Entry at 11-12, ⁋32 (Oct. 22, 2018)

AEP Ohio has unequivocally conceded that it cannot establish "need" for these facilities under R.C. 4928.143(B)(2)(c) pursuant to this Commission's precedent, *i.e.*, that, based on resource planning projections, generation needs cannot otherwise be met through the competitive market. *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Officer*, PUCO Case Nos. 11-346-EL-SSO), et al., p. 39 (Dec. 14, 2011); *In re Long Term Forecast Report of Ohio Power Co.*, PUCO Case Nos. 10-501-EL-FOR and 10-502-EL-FOR (Jan. 9, 2013). Indeed, in its Amendment, AEP Ohio readily acknowledges that "*PJM wholesale markets are adequately supplying capacity* and energy to the AEP Ohio load zone. *** *Nor is the Company proposing through this filing that it has a traditional integrated resource planning (IRP) need for generation.*" Amendment at 3 (emphasis added).

Notwithstanding the express provisions of R.C. 4928.143(B)(2)(c) and established Commission precedent, AEP Ohio has attempted to define (or redefine) "need" in its Amendment in terms of the relative costs of renewable energy projects, and in doing so, relies exclusively on assertions regarding "generic" solar and wind projects to demonstrate purported "economic benefit". Additionally, AEP Ohio relies on an unsupported "customer survey" to show that customers "want" or "desire" renewable energy and claimed job creation and "economic development benefits" to justify its requested relief in this case. These claims are wholly irrelevant to the mandatory provisions of R.C. 4928.143(B)(2)(c).

The Commission's Staff has independently confirmed that there is no capacity or energy "need" for 900 MW of renewable energy projects based on integrated resource planning. The competitive PJM Market is more than adequate to service capacity and energy needs and AEP Ohio disclaims that the projects are necessary to satisfy Renewable Portfolio Standards under R.C. 4928.64. (Benedict, Staff Ex. 2; Siegfried, Staff Ex. 1). AEP Ohio's reliance on purported "generic" economic benefit, customer "wants" or "desires", and "economic development" benefits are wholly irrelevant to the demonstration of "need" based on integrated resource planning as required by R.C. 4928.143(B)(2)(c). Claimed "economic development benefits" are irrelevant to the issue of "need" or any other issue under R.C. 4928.143(B)(2)(c). See *In the Matter of the Long-Term Forecast of Ohio Power and Related Matters*, Case No. 10-501-EL-FOR et seq., Opinion and Order at 25-27 (Jan. 9, 2013).

Staff's position is supported by the majority of stakeholders in this case - the Office of Consumers' Counsel, the Ohio Manufacturer's Association, the Industrial Energy Users, Kroger, Direct Energy, Interstate Gas Supply, and the Ohio Coal Association. These parties have offered highly qualified expert witnesses and substantial documentary evidence to refute AEP Ohio's claims in this case. AEP Ohio's supporters are environmental groups which are more concerned with environmental issues than the "need" or costs of projects.

Significantly, AEP Ohio itself unilaterally imposes at least five (5) conditions to its proceeding with its own proposal for the two specific facilities at issue. These conditions are:

1. The PUCO must approve the REPAs as prudent in their entirety.

2. The PUCO must find the requisite "need" for these two specific solar facilities under R.C. 4928.143(B)(2)(c).

3. The PUCO must approve the requested nonbypassable surcharge covering claimed "costs" for the 20 year life of the REPAs.

4. In approving the nonbypassable surcharge, the PUCO must allow recovery of the proposed debt equivalency charge - a cost of over $110 million over the twenty year life of the REPAs.

5. The PUCO must allow recovery of the requested capacity performance assessment charge. (OCA Ex. 2, REB - 1, pp. 1, 8).

Absent Commission acceptance of these unilateral pre-conditions, AEP Ohio will not proceed with its own proposal and the REPAs will terminate. Accordingly, it is apparent that AEP Ohio unilaterally conditions the purported "need" for the two solar projects at issue on cost recovery acceptable to AEP Ohio.

There is no barrier to another affiliate of AEP - AEP Energy, AEP Renewables or another affiliate - to develop renewable energy projects, or other energy generation resources, in the competitive market. If AEP really believes the projects are economically beneficial, it is free to develop the projects at its benefit and risk rather than to invoke the limited exception of R.C. 4928.143(B)(2)(c) to force captive customers to subsidize and guarantee the projects.

Since there is no "need" for the projects based on resource planning, the standard that defines "need" under R.C. 4928.143(B)(2)(c), AEP Ohio cannot satisfy the predicate condition under R.C. 4928.143(B)(2)(c) and no nonbypassable surcharge is merited. The case should be summarily dismissed and the relief sought by AEP Ohio denied.

II. THE PREDICATE CONDITION OF "NEED" UNDER R.C. 4928.143(B)(2)(c)

R.C. 4928.143(B)(2)(c) is a limited statute authorizing an electric distribution utility to recover the costs of a qualifying facility specified in the application through a nonbypassable surcharge for the life of the facility but only if there is to a demonstrated "need" for the facility.

The specific facility at issue must be owned or operated by the EDU and the source must be competitively bid. The statute presents a very narrow and restricted exception to the State scheme to deregulate utility generation resources to permit and implement generation resource competition. AEP Ohio's proposal in these cases would permit AEP Ohio to re-enter the regulated generation environment to contract for unneeded solar generation capacity and energy, at total costs in excess of the competitive market, replete with artificial tax credits and incentives to subsidize the facility and pass 100% of the costs on to both jurisdictional captive customers and shopping customers through the nonbypassable surcharge. This proposal, viewed in its entirety, violates R.C. 4928.143(B)(2)(c) and is inconsistent with the State's stated policy under R.C. 4928.02.

R.C. 4928.143(B)(2)(c) provides that an electric security plan filed by an electric distribution utility may include:

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

R.C. 4928.143(B)(2)(c) expressly provides for six (6) predicate conditions to satisfy the narrow exception of the statute. These predicate conditions are:

1. The specific generating facility at issue must be directly *owned* or *operated* by the EDU.

2. The specific facility must be newly used and useful on or after January 1, 2009 and must be *sourced* through a qualifying *competitive bid process*.

3. The EDU may establish a nonbypassable surcharge to cover *costs of the utility specified in the application*.

4. No surcharge shall be authorized *unless* the Commission first determines in the proceeding that there is a *need* for the facility proposed *based on resource planning projections* submitted by the EDU.

5. The EDU shall dedicate to Ohio consumers the *capacity* and *energy* and the *rate* associated with the *cost* of that *specific facility*.

6. Before authorizing the surcharge, the Commission may consider, as applicable, the effects of any decommissioning, deratings and retirements.

As noted above, the Commission has previously ascribed a narrow meaning of the word "need" consistent with the unambiguous provisions of R.C. 4928.143(B)(2)(c). The Commission has held that "need" is established only when, based on resource planning projections, generation needs cannot be met through the competitive market. *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company For Authority to Establish a Standard Service Offer*, PUCO Case Nos. 11-346-EL-SSO, et al., at p. 39 (Dec. 14, 2011) ("While Section 4928.143(b)(2), Revised Code provides the Commission with authority to order construction of new generation facilities in Ohio, such new generation or capacity projects will only be authorized when generation needs cannot be met through the competitive market.") See also *In re Long Term Forecast Report of Ohio Power Co.*, PUCO Case Nos. 10-501-EL-FOR & 10-502-EL-FOR (Jan. 9, 2013) ("The Commission noted that it would first look to the market to build needed capacity and that new generation or capacity projects would only be authorized under Section 4928.143(B)(2), Revised Code, when generation needs cannot be met through the competitive market.").

The Commission also concluded that "need" under R.C. 4928.143(B)(2)(c) must be established for specific generating facility at issue. *Id*. at 27 (finding no demonstration of "need" under R.C. 4928.143(B)(2)(c) for the specific "Turning Point" project at issue). Job creation and socio-economic benefits are not relevant under R.C. 4928.143(B)(2)(c). *Id* at 25-27.

Contrary to AEP Ohio's position, "need" is well-defined in the statute. "Need" is based on "resource planning projections". "Need" is determined with reference to the *specific* facility at issue and the *capacity* and *energy* of that *specific* facility must be dedicated to the Ohio resources that bear the nonbypassable surcharge. "Need" is not dependent on the nature of the generation - renewable or otherwise, is not dependent on the relative costs or benefits of the generation source, is not dependent on "wants" or "desires" of customers and is not dependent on purported "economic development" benefits.

As respects renewable energy resources, the Ohio General Assembly has independently provided benchmark portfolio standards in R.C. 4928.64 for "qualifying renewable energy resources". Those benchmarks are subject to separate conditions, including a cost cap and a bypassable surcharge (rather than a nonbypassable surcharge) and do not require exclusively in-state generation resources.

There is no legitimate basis for AEP Ohio's attempt to expand the meaning of "need" beyond that provided in the statute itself. R.C. 4928.143(B)(2)(c) is unambiguous - "need" is based on resource planning projections. The Commission cannot "read words into or out of that statute but must accept the enactment of the General Assembly as it stands." *State v. Stevens*, 161 Ohio St. 432, 435 (1954); *State ex rel. Solomon v. Board of Trustees*, 72 Ohio St. 3d, 62, 65

(1995). The Commission "must give effect to the plain meaning of the words used in a statute, and ". . . must not modify an unambiguous statute by adding or deleting words." *State v. Steele*, 138 Ohio St. 3d.1, 4, 2013 - Ohio - 2470 at ⁋17 (2013).

III. THE RECORD UNEQUIVOCALLY ESTABLISHES THAT THERE IS NO CAPACITY OR ENERGY NEED FOR THE PROJECTS AT ISSUE BASED ON THE COMPANY'S OWN RESOURCE PLANNING PROJECTIONS.

Significantly, as noted above, AEP Ohio admits that there is no need for supply of capacity and energy in the AEP Ohio load zone and disclaims that additional solar or wind generation resources are necessary to meet the benchmarks of R.C. 4928.24. (AEP Ex. 2, Amendment at 3.) Nor is AEP Ohio proposing that there is a traditional integrated resource planning need (IRP) for this generation. *Id*.

AEP Ohio Witness Allen acknowledges that OAC Rule 4901:5-06(B) requires that an LTFR filing include an integrated resource plan (IRP) if a company intends to file for a nonbypassable surcharge under R.C. 4928.143(B)(2)(c). Inconsistently, Allen asserts that AEP Ohio is not requesting a finding of "need" under R.C. 4928.143(B)(2)(c) for any *specific* renewable project - particularly the Hecate and Willowbrook projects. (AEP Ex. 3, pp. 3-4).

AEP Ohio offers its 2018 Long Term Forecast Report which projects resource needs ten (10) years out. (AEP Ex. 1). AEP Ohio purchases capacity and energy through the PJM competitive market. AEP Ohio reports sufficient resources to serve a native load providing an adequate reserve over the projection forecast. (AEP Ex. 1, pp. 100-110; Form FE R-1-R-9). Although AEP Ohio already has contractual entitlements for solar and wind generation - Fowler Ridge II, (Wind, 100 MW), Wyandot Solar (Solar, 10 MW) and Timber Road (Wind, 100 MW) - none of these renewable generation resources are designated to serve the AEP Ohio peak load. (AEP Ex. 1, pp. 103-106; Vol. II, 265).

The Commission Staff independently reviewed AEP Ohio's LTFR and confirmed that there is no capacity or energy need for the subject facilities based on resource planning projections. Staff Witness Siegfried confirmed that AEP Ohio does not need Renewable Energy Credits (RECs) or Solar RECs from a proposed 900 MW of renewable energy resources to meet the RPS mandates. (Siegfried, Staff Ex. 1, pp 2-4). Staff Witness Benedict confirmed that AEP Ohio does not need capacity or energy from the projects to serve its customers. The PJM market is more than adequate to serve the Company's needs. (Benedict, Staff Ex. 2).

Staff Witness Benedict is Senior Utility Specialist in the Office of Federal Energy Advocate. Mr. Benedict explained that Integrated Resource Plans (IRP) under OAC Rule 4901:5-5-06 became largely obsolete with deregulation since all investor owned EDUs have been fully sourcing generation needs in the PJM competitive market. The exception is R.C. 4928.143(B)(2)(c) which permits nonbypassable cost recovery for new generation facilities conditioned upon a finding of "need" within the context of a forecast filing. (Staff Ex. 2, p. 2).

The first step in an IRP review is to determine whether the energy and demand forecasts are reasonable. Staff confirmed that AEP Ohio's forecasts are reasonable and the methodologies adequate. (Staff Ex. 2, p. 5).

The next distinct step in the process is to determine whether sufficient resources exist to serve demand including a reasonable reserve margin. Staff reviewed AEP Ohio's LTFR and concluded there was no need for capacity or energy to serve the AEP Ohio service load. Staff concluded that PJM's most recent Base Residual Auction in May, 2018 resulted in a reserve margin of 21.5% well in excess of the target of 15.8%. Further, PJM's Reliability Pricing Model (RPM) has consistently procured capacity at levels exceeding standards for resource adequacy.

Staff independently confirmed AEP Ohio's admission that the PJM Market more than adequately serves AEP Ohio's capacity, energy and reliability needs. (Staff Ex. 2, pp. 7-8).

Given that there is no demonstrated "need" for the proposed projects based on resource planning, there is no basis to proceed to next steps to determine whether the specific projects proposed are the "least cost resource option." "Least cost resource options" could include considerations such as cost, flexibility, environmental attributes, dispatch availability, fuel diversity and economic impact. (Staff Ex. 2, pp. 4-8). However, AEP Ohio attempts to put the "cart before the horse." There is simply no basis to consider options as "least cost resource options" absent a demonstrated "need" for capacity and energy resources in the first place. (*Id*., p. 8).

Staff also refuted AEP Ohio's reliance on the Navigant survey as a confusion of "want" versus "need." Staff explained that there were competitive market options available to respond to any customer desire for renewable energy. These offerings included net metering, CRES offerings and government aggregation. Specifically, as of November 8, 2018, residential customers in the AEP service area had 29 CRES provider offerings with 100% renewable content and small commercial (GS-I) customers had 14 CRES offerings with 100% renewable content. Staff's concern was that AEP Ohio's proposal to invoke R.C. 4928.143(B)(2)(c) would provide a disincentive to the competitive market place. (*Id*., pp. 9-11).

Staff's position is clearly consistent with R.C. 4928.143(B)(2)(c) which requires a predicate showing of "need" based on resource planning projections and with prior Commission precedent. (Benedict, Vol. VIII, 2292, 2317). The position also makes good common sense. There is no basis for an EDU to proceed with costly resource facilities under R.C.

4928.143(B)(6)(c) when there is no demonstrated "need" for the facilities to serve capacity or energy demands in the first place.

Staff's position is supported by the majority of stakeholders in this case.

OCA Witness Dr. Richard E. Brown is an industry-recognized expert on electric power systems, electric utility economic assessments and benefit-to-cost assessments. (OCA Ex. 2, pp. 2-3). Dr. Brown's Expert Report is submitted as REB Exhibit 1. Ohio is obviously a deregulated state. The intent of deregulation is to create competition among wholesale electricity generators to achieve cost-efficiencies in the free market. (REB Ex. 1, pp. 5-7). Ohio has established Alternative Energy Portfolio Standards. AEP Ohio already meets the RPS standards without the proposed projects. (REB Ex. 1, pp. 12-13). As admitted by AEP Ohio, there is no "need" for the proposed projects based on resource planning projects. Forecasted generation capacity is sufficient to meet AEP Ohio's own forecasted energy demand based on the LTFR. (REB Ex. 1, p. 30).

OCA Witness Emily Medine is a Principal in the consulting firm of Energy Ventures Analysis, Inc. Ms. Medine has extensive experience in the electric utility industry representing clients in the industry and a number of public agencies including the U.S. Department of Justice, the U.S. Department of Interior and various state public utility commissions. She has performed over 25 audits of utilities regulated by this Commission and has testified in a number of proceedings before this Commission, including audits of AEP Ohio. (OCA Ex. 3, p. 2; Attachment ESM-1).

Ms. Medine concludes that AEP Ohio has fulfilled its obligation to *propose* to develop 900 MW of renewable generation based on the Stipulation in the earlier Commission cases - Case No. 14-1693-EL-RDR and Case No. 16-1852-EL-SSO. There is, however, nothing in the

Stipulation requiring the Commission to *accept* AEP Ohio's proposal absent a demonstrated "need" for the facilities under R.C. 4928.143(B)(2)(c). (OCA Ex. 3, pp. 3, 6-10).

Other Intervenor Experts likewise support the Staff position based on their independent assessments. All concluded that there was no "need" for the projects based on resource planning projections. See Dr. Jonathan Lesser, (OCC Ex. 18, pp. 4-6-8); Joseph Haugen, (IGS Ex. 10, p. 5); Matthew White (IGS Ex. 12, p. 17); Kevin Murray (IEU Ex. 1, p. 5, KMM-2); John Seryak (OMAEG Ex. 16, p. 8); Justin Bieber (Kroger Ex. 4, p. 5). Kevin Murray testified that PJM's recent Base Residual Auction cleared 163,627.3 MW of unforced capacity representing a 22% resource margin more than enough to meet target reserves. (IEU Ex. 1, p. 5; KMM-2). Dr. Lesser additionally noted that based on the 2018 PJM Reserve Requirement Study, October 10, 2018 (OCC Ex. JAL-7), PJM forecasted reserve of 28.7% in 2018, increasing to 36.2% in 2021 and maintaining at 31.2% in 2018. (OCC Ex. 18, p. 14).

In short, by AEP Ohio's own admission and as unequivocally confirmed by the Staff and Intervenors, AEP Ohio cannot demonstrate any "need" for the projects based on resource planning projections. AEP Ohio has wholly failed to satisfy the predicate condition of R.C. 4928.143(B)(2)(c) and these cases should be summarily dismissed and the requested relief denied. The remainder of AEP Ohio's contentions are irrelevant.

IV. THE PJM MARKET IS A COMPETITIVE MARKET THAT PROVIDES DIVERSE, RELIABLE AND EFFICIENT ENERGY RESOURCES. THERE IS NO BASIS TO INVOKE THE LIMITED EXCEPTION OF R.C. 4928.143(B)(2)(c) TO FORCE CAPTIVE CUSTOMERS TO GUARANTEE AND SUBSIDIZE THE PROPOSED RENEWABLES PROJECTS.

The PJM Market is a competitive market providing a diverse resource mix of coal-fired, natural gas-fired, nuclear and renewables resources. (Allen, Vol. I, 269). The PJM Market addresses flexibility, resource diversity, reliability and ancillary services. (*Id*., 270). The greatest benefit of membership in PJM is the pooling of generation and transmission services across thirteen (13) states and the District of Columbia. (Benedict, Vol. VII, 2343).

PJM operates independently subject to FERC jurisdiction over the wholesale market and NERC jurisdiction over planning and reliability issues. With deregulation, this Commission has no direct authority to dictate generation resources in the deregulated market. Likewise, AEP Ohio is no longer a vertically integrated electric utility and generally is prohibited from engaging in the generation market. (Allen, Vol. I-97, 270; OCA Witness Brown, REB Ex. 1, pp. 5-7). AEP Ohio, like the other electric distribution utilities operating in Ohio, procures competitive energy and capacity resources through the PJM Market. (REB Ex. 1, pp. 5-7).

AEP Ohio's proposal to enter into fixed-price REPAs over a twenty (20) year term under the limited exception of R.C. 4928.143(B)(2)(c) is inconsistent with the free PJM competitive market, provides a guarantee and state out-of-market subsidy for the renewable energy projects, distorts the operation of the PJM Market and is anticompetitive. (OCA Witness Brown, REB Ex. 1, pp. 37, 47-55; OCA Witness Medine, OCA Ex. 3, pp. 21-24).

A. The PJM Market Is A Diverse, Reliable And Efficient Energy and Capacity Market

The PJM Market has 195,000 MW of installed capacity-more than enough capacity to meet demand of 168,000 MW. (Ali, Vol. II, 427). Across the load, new generation resources are being developed regardless of LMP pricing considerations. (Ali, Vol. II, 437). Generation resources are currently 33% coal-fired, 33% natural gas-fired, 18% nuclear and 6% renewables including wind and solar. (Medine, OCA Ex. 3, Attachment ESM-3, pp. 9-10; Benedict, Vol. VIII, 2375; Allen, Vol. I, 269). Coal-fired generation is the "backbone" of the PJM capacity market. PJM employs 56,000 MW of coal-fired capacity which is over 20% of the entire U.S. coal fleet. (Medine, OCA Ex. 3, Attachment EJM-3, p. 2). Of that 56,000 MW of installed capacity, merchant generation provided 34,569 MW of coal-fired capacity while regulated utilities provided the balance. (*Id*., p. 4). Coal-fired generation offers resiliency and reliability attributes not provided by renewable resources. During the Polar Vortex of 2014 and the "Bomb Cyclone" of 2018, coal-fired generation was critical in meeting extraordinary demands. (*Id*., p. 3).

B. Renewable Resources, Including Both Wind and Solar, Do Not Materially Promote System Capacity, Flexibility, Load Regulation Or Other Ancillary Requirements.

Renewable generation resources have an advantage of zero fuel costs but cannot contribute materially to PJM system capacity, flexibility, load regulation or other ancillary requirements. These resources are, by nature, intermittent resources dependent on location, wind pattern and sunlight. (Medine, OCA Ex. 3, Attachment ESM-3, pp. 4, 9).

AEP Witness Ali conceded that the proposed solar projects will not meaningfully impact rate stability in the PJM Market given the projects are only 1/2% of PJM installed capacity. (Vol. II, 416). He testified that the PJM Market is an efficient market where the most cost-effective units are dispatched first. (Vol. II, 418) Renewable resources cannot, and will not, displace the capacity of baseload units because of their intermittent nature but will displace energy produced by baseload units depending on the availability of the renewables resources. (*Id*., 418). There will still be required baseload provided spinning reserve when renewable resources are not available. (*Id*., 418-419). Renewables are not expected to meaningfully impact frequency response, voltage regulation, ramping, load following or reserve requirements of the system because of the resource variability and intermittent nature. Mr. Ali did not consider either the benefit nor the liabilities of these ancillary system requirements in his LMP analysis. (Vol. II, 419-420). His analysis included no analysis of capacity impact at all and was focused solely on the energy impacts. (*Id*., 422). Renewables are not valued for capacity benefits and PJM discounts renewable capacity values. (*Id*., 422, 424). Mr. Ali did not consider "uplift" costs. which routinely apply when units are dispatched for reliability purposes, even though "uplift" costs definitely result in a loss of revenues in the system. (Vol. II, 417, 453). In fact, renewables are a detriment to the system since PJM is required to carry higher reserves to compensate for the inherent variability of renewables resources. (Ali, Vol. II, 453, 459).

OCA Witness Brown concludes that given low capacity values for renewables, renewables cannot, and will not, displace baseload generation. If 1000 MW of capacity is necessary, a renewable resource with a capacity value of 19% will only contribute, at best, 190 MW of required capacity. 810 MW of existing or new baseload generation will still be required. (OCA Ex. 2, REB Ex. 1, p. 47). Nor can renewables contribute to ancillary service requirements including load following, regulation and reserve. (*Id*., at p. 50-51). In fact, large scale solar generation can adversely impact reliability and may increase the ancillary services that load-serving entities are required to provide. (*Id*., p. 51).

C. Renewables Resources Are Heavily Subsidized Energy Resources That Distort The Market.

Renewables resources are heavily subsidized through the Investment Tax Credit and Production Tax Credit. The PTC generates $24/MWH for wind and $12/MWH for solar. The ITC generates fixed contributions for utility investments. Given these tax incentives, coupled with zero fuel costs, renewables will be automatically dispatched displacing available energy output from baseload units. (Ali, Vol. II, 413). Wind production receives the PTC at $24/MWH even overnight when demand diminishes and can be dispatched at zero energy or even negative energy prices. This adversely impacts baseload operation and distorts the market. (Medine, Vol. VII, 1928, 1930, 1945; Brown, OCA Ex. 2, REB Ex. 1, pp. 52-55).

Ms. Medine concluded that renewables resources cannot displace baseload generation and, in fact, distort the market. Given low capacity values, it would require 30,000 MW of wind generation at a capacity cost of $59 billion to replace 5,255 MW of coal fired generation capacity recently retired. (OCA Ex. 3, Attachment ESM 3, p. 12). Given declining solar installation costs, solar projects can stand on their own merits without subsidies out-of-market. (Medine, Vol. VII, 1915, 1928). The Wind PTC is an unwarranted subsidy that distorts the market since wind facilities dump energy into the overnight market at very low or negative prices, displacing baseload coal-fired generation even though coal-fired generation is typically available and less expensive in other hours. (*Id*., p. 1945).

Renewable resources are also subsidized by state sponsored Renewable Energy Portfolio Mandates. This is true in Ohio as well as Ohio has implemented mandatory portfolio benchmarks in R.C. 4928.64. (Medine, Vol. VII, 1928). Significantly, AEP Ohio does not attempt to justify the REPAs proposed as necessary to meet these portfolio requirements. AEP Ohio has satisfied benchmarks and will do so for the next ten (10) years or more. (Allen, Vol. I, 117, 160, 210; Brown, OCA Ex. 2, REB Ex. 1, pp. 12-13).

OCA Witness Brown concludes that the Highland and Willowbrook projects should compete on equal footing in the competitive market. Since Ohio is part of the deregulated market, no new generation facilities should receive state subsidization providing an advantage of one resource over another. It is particularly true that state sponsored subsidization should not come from electricity customers. (OCA Ex. 2, REB Ex. 1, p. 9). Interfering with the PJM Market by subsidizing renewable resources results in a less efficient and distorted market. (*Id*., p. 37).

AEP Ohio asserts that Ohio is a net importer of energy and there is a need for new, in - state renewable generation. The fact of the matter is that Ohio has been a net importer of energy for years, before and after deregulation. (Allen, Vol. I, 99, 101 -102, 210). Furthermore, in-state generation resources have declined in large part to premature retirement of in-state coal generation units by electric utilities including AEP. (Medine, Vol. VII, 1629).

In any event, the Ohio General Assembly in Senate Bill 310 eliminated the in-state mandate for renewables in the RPS. These in-state mandates were eliminated due to the excessive cost of in-state renewables. Accordingly, the Ohio General Assembly has not seen fit to mandate in-state renewables resources. (White, IGS Ex. 12, pp. 6-8; Allen, Vol. I, 77).

Moreover, FERC is presently considering changes in PJM capacity rules to address, or mitigate, state out-of-market subsidization for generation resources. In *Calpine Corp. v. PJM Interconnection, LLC*, FERC Case Nos. EL-16-49-000, EL 18,314-000, EL 18, 314-001 and EL 18-178-000, FERC is addressing price suppression effects resulting from state out-of-market support for renewables resources. PJM has filed proposed capacity market rule changes which would allow state subsidized resources to submit a bid at Minimum Offer Price Rules (MOPR) or the capacity would fall under the Resource Carve-Out option. (Haugen, IGS Ex. 10, p. 5). AEP Ohio has totally ignored this significant potential action in its benefit analysis. (Torpey, Vol. V, 1318). If these rules changes are adopted, AEP Ohio would likely not be able to receive any capacity revenues for the REPA sources and its customers would bear that risk.

D. The Competitive Market Offers Market Driven Alternatives To Supply Renewable Generation Resources. AEP's REPA Artifact Is Anticompetitive.

AEP Ohio concedes that the PJM Market offers market driven alternatives to supply renewable generation resources. Merchant generators can, and do, make their own choices for generation which depend on relative economics and a wide variety of economic considerations. (Allen, Vol. I, 276). Nothing precludes AEP Energy, AEP Renewables or another affiliate from entering into bilateral arrangements, joint ventures or self-construction to build and market renewables resources. (Allen, Vol. I, 155, 163, 181, 275). (Lesser, OCC Ex. 18, pp. 13-14). Utility scale resources can be, and are being developed, without the REPA artifact. (Medine, Vol. VII, 1958, 1963).

OCA Exhibits 4 and 5 reflect both currently operating and pending wind and solar projects in Ohio. Utility scale wind and solar projects are subject to the siting authority of the Ohio Power Siting Board (OPSB). There are 327 operating wind turbines in Ohio providing 669.8 MW of generation. There are 794 potential turbines pending OPSB approval providing 1910 MW of capacity. There are also 1,249.9 MW of solar facilities pending for OPSB approval - including Hardin Solar, Alamo Solar, Angelina Solar, Vinton Solar and Hilcrest Solar. All are utility scale projects.

The record is replete with evidence of renewables alternatives available in the market and offered by CRES providers including Intervenors in this case. (Rever, IGS Ex. 9, p. 5; Haugen, IGS. Ex. 10, p. 4; Murray, IEU Ex. 1, p. 12; White, IGS Ex. 12, pp. 17-18; Sioshonsi, OCC Ex. 25, p. 22). Renewable energy can be supplied by CRESs providers with as much as 100% renewables sourcing. As discussed above, Staff Witness Benedict testified that there are alternatives available in the market. As of November 8, 2018, residential customers in the AEP load had 29 CRES offerings with 100% renewables and small commercial, GS-1, had 14 offers with 100% renewables. There are also "Green Tariff" options, net metering options and governmental aggregation programs available in the market. (Benedict, Staff Ex. 2, p. 10). The Staff is concerned that AEP's proposal would crowd out these competitive offerings. (*Id.*, p. 11).

In sum, AEP Ohio's REPA proposal distorts the market and is anticompetitive. Additionally, there is no assurance that the output of any REPA will actually serve Ohio customers. AEP Ohio reserves the option of entering into "reasonable arrangements" for the output. (Allen, Vol. I, 208). In any event, in the PJM Market, output is liquidated into the market and the provider then purchases needs in the market. (Allen, Vol. I, 287). There is no assurances Ohio customers will receive any purported benefit of these proposed renewables projects. (Torpey, Vol. V, 1422, 1424; Lesser, OCC Ex. 18, p. 20).

V. AEP OHIO'S CONTORTED PERCEPTION OF "NEED" IS SELF-SERVING, IRRELEVANT AND INCONSISTENT WITH THE PREDICATE CONDITIONS OF R.C. 4928.143(B)(2)(c).

Acknowledging that there is no capacity or energy "need" for 900 MW of renewable energy based on resource planning, AEP Ohio attempts to redefine and enlarge the meaning of "need" beyond that addressed in R.C. 4928.143(B)(2)(c). AEP Ohio redefines "need" to include:

1. Consideration of claimed cost/benefit of renewable resources;
2. Customer "wants" or "desires" for renewable energy; and
3. Economic benefit to the Ohio economy.

As discussed above, none of these considerations are relevant to the "need" for the facilities based on resource planning as required by R.C. 4928.143(B)(2)(c).

In this case, AEP Ohio contends that there is a *generic* need for 900 MW of renewable energy projects. The AEP Ohio focuses exclusively on *generic* renewable resources rather than the two specific solar generation projects at issue - Highland and Willowbrook. AEP Ohio relies principally on Witness Torpey to demonstrate claimed economic benefits of *generic* renewable energy projects. The operation, design, output, costs, cost allocation, capacity factors and reliability of the specific sources at issue can only be determined by critical examination of the actual REPAs at issue. AEP Ohio's hypothetical, *generic* cost analysis provides no real-world economic cost/benefit analysis of the two specific solar projects at issue under R.C. 4928.143(B)(2)(c).

A. Commissions In Other Recent Cases Have Rejected AEP's Forecasted Cost/Benefits Analysis.

This Commission would be well-served to note that AEP Ohio's forecasted analysis of cost/benefit has been soundly rejected by other state Commissions in very recent cases.

In *Re Application of Appalachian Power Company For A Rate Adjustment Clause Pursuant To § 56-581.1A6 of The Code of Virginia*, Virginia State Corporation Commission, Case No. PUR-2017-0031, Order Dated April 2, 2018, Appalachian Power Company (APCO) filed an application seeking approval of a rate adjustment clause to recover costs associated with the Company's proposed acquisition of the Beech Ridge II and Hardin wind generation facilities. APCO, as in the present case, did not assert a capacity need for the facilities. Rather, it asserted the facilities were needed to provide a lower cost of energy compared to the PJM market particularly during winter months. The Virginia Commission found, however, that APCO's forecasted energy and natural gas prices were inflated compared to market and other independent forecasts. For example, APCO forecasted natural gas prices at the Henry Hub were \$4.89/MMBTU for 2018 compared to the EIA forecast of \$2.88/MMBTU for 2018. (*Id*. p. 5). The Virginia Commission further found that APCO had not established that the facilities were needed as a hedge against market volatility. APCO conducted no analysis of the costs and benefits of such a hedge or that facilities provided a superior hedge compared to other available alternatives. The Virginia Commission rejected APCO's application holding:

> Put simply, the capacity and energy from these generating facilities is not needed by APCO to serve its Virginia customers. Thus, we find that it is neither

> reasonable nor prudent for APCO to acquire the Wind Facilities and then recover the costs from Virginia customers based on the record before us. (*Id*., p. 2).

In its Order Denying Reconsideration dated April 20, 2018, the Virginia Commission found additional reasons for denying the application. The Virginia Commission found claimed benefits were highly speculative depending on fluctuating prices for 25 years while the increased cost for the facilities was locked in for those 25 years. The Commission also found that APCO narrowly focused on cost of facilities over the first 10 years of service life only. The Production Tax Credit would end after the first 10 years, resulting in substantially higher cost of facilities over the remainder of the 25 years. (Order Denying Reconsideration, p. 3).

In *Re: Petition of Appalachian Power Company and Wheeling Power Company For Consent And Approval Of Acquisition of Wind Facilities*, Public Service Commission of West Virginia, Commission Order Dated May 30, 2018, the West Virginia Commission also considered a petition filed on July 5, 2017 for the acquisition of the Hardin Wind and Beech Ridge II wind generation facilities. The companies requested a rate surcharge to recover the costs of the facilities. The companies admitted, as here, that there was no capacity need for the facilities. (*Id*., p. 7). Rather, the companies asserted that the proposed acquisition was justified to provide a net cost savings to consumers, to take advantage of the Production Tax Credit, to promote diversity and to provide a hedge against market prices and projects impacted by future carbon regulation. (*Id*. pp. 1-6).

The West Virginia Commission found that AEP's Fundamentals Forecast was suspect and overly aggressive in projecting future PJM Market prices. (*Id*., pp. 13-14). The Commission found that AEP forecasted Henry Hub prices increasing by about 200% in the first ten years and over 427% extending to 2046. The West Virginia Commission found:

> ". . . We are concerned that the benefit of owning the Wind Facilities is supported by PJM Market price projections that are dependent on the Companies' 2016 Fundamentals Forecast showing near term Henry Hub price increases of 200% and 300% increases in Appalachian gas prices. We are equally concerned by the extended projection of 427% to 650% longer term increases in natural gas prices over the period of time generally covering the life of the Wind Facilities." (*Id*., p. 13).

The West Virginia Commission was also critical of the companies' reliance on future carbon burden costs.

> ". . . There are not now, nor have there been, carbon regulations imposing burden on generators. Although it may be prudent for the Companies to consider the effect of possible carbon regulations on future costs, to rely completely on possible regulations that will occur in the near future and may not occur in the distant future is too speculative to impose on current ratepayers." (*Id*., p. 14).

Additionally, the West Virginia Commission found that the Production Tax Credit would phase out in years 11-25 resulting in much higher revenue requirements than in the first 10 years of the project. This would result in future customers paying higher rates than current customers. (*Id*., p. 8). Finally, the Commission found that there was insufficient evidence to clearly demonstrate a net cost savings and the Monte Carlo probalistic simulation was speculative. (*Id*., p. 9-10, 12).

In conclusion, the West Virginia Commission rejected the Companies' application holding:

> "Accordingly, we base our decision on the Companies' proposed rate setting request, the potential benefits and detriments that acquisition of the Wind Facilities bring to the table and the fact that the required VSCC approval has been denied. Considering the lack of need for capacity, the availability of ample energy supplies from the PJM Market, the uneven potential benefits of the Wind Facilities as compared to the market option due to the fly-up revenue requirements beginning in eleven years and continuing for fifteen years thereafter, the aggressive projections of gas prices and PJM market price escalation over the next twenty-five years, the uncertainty of the timing and impact of carbon regulations and their associated impact on market prices and fossil fuel generation, the uncertainty of the per unit value of RECs that would offset the costs of the Wind Facilities, and the complete lack of any record on how we go

forward with the Wind Facilities acquisition in view of the denial by the VSCC, the proposed acquisition, under the conditions and circumstances set forth in this record, are not in the public interest in West Virginia." (*Id*., p. 15).

Finally, in *Re Application of Southwestern Electric Power Company For Certificate of Convenience and Necessity Authorization And Related Relief For the Wind Catcher Energy Connection Project In Oklahoma*, Public Utility Commission of Texas, PUC Docket No. 47461, SOAH Docket No. 473-17-5481 (Order Dated August 13, 2018), the Texas PUC rejected SWEPCO's application for authorization to acquire 70% of the 2000 MW Wind Catcher generating facility. The Texas PUC concluded that SWEPCO failed to show the project would result in probable cost savings to SWEPCO customers and, consequently, failed to show the project was necessary for the service, accommodation, convenience or safety of the public.

Again, SWEPCO, as here, acknowledged that the project was not needed to serve load or address capacity issues. Instead, SWEPCO asserted that the project would provide cost savings to consumers. (*Id*., p. 2). The central issue was the forecast of future natural gas prices provided in the AEP Fundamentals Forecast. The Texas PUC found that the Fundamentals Forecast grossly overstated base case forecasts of natural gas prices. Forecasted prices based on EIA forecasts and NYMEX exchange prices were much lower. Depending on the range of forecasted prices, cost impact would vary from savings of $912 million to net costs of $1.971 billion. (*Id*., p. 2). The Commission also criticized the SWEPCO's assumed future carbon tax used in the modeling which impacted cost savings by $550 million. The Commission found there was no credible evidence to show imposition of the assumed carbon tax was likely. Finally, the Commission found significant that SWEPCO assumed a 51% net capacity factor for the wind generation but was unwilling to guarantee that performance.

The approach relied upon by AEP Ohio in this case is virtually identical to the approach offered by AEP affiliates in this recent case and rejected by three (3) State Commissions in the last year. The evidence establishes that AEP Witness Bletzacker sponsored the Fundamentals Forecast in the Texas Wind Catcher case (Vol. III, 783) and AEP Witness Torpey sponsored the economic benefits analysis in the Virginia and West Virginia cases. (Vol. V, 1383-1412). This Commission should follow the lead of these other state Commissions and reject the AEP Ohio approach for the same reasons as asserted as the basis for rejection in the three recent cases.

B. AEP's Locational Marginal Pricing (LMP) Savings Analysis
Was Flawed From The Beginning And Never Fully Corrected.

AEP Witness Ali initially presented his analysis of Locational Marginal Pricing (LMP) and estimated savings assuming new generation sources for 650 MW of wind and solar facilities. (AEP Ex. 5). PJM uses LMP to establish the price of energy purchases and sales in the PJM wholesale electricity market. LMP reflects the value of energy at the specific location and time it is delivered. LMPs are calculated by PJM's computer systems and posted to the website every five (5) minutes. LMP pricing has three (3) components: (1) an energy component; (2) a congestion component; and (3) a "loss" component. Pricing applies at relevant pricing "nodes" in the PJM Market and applies to day-ahead and realtime dispatching. LMP provides the bases for *payments* to generators and *payments* by buyers determined at the relevant node. Cash settlements are made after the fact. (AEP Ex. 5, p. 3; Vol. II, 412-413, 445-446, 501-502, 503-505; Vol. XII, 2782, 2784-2790).

Where there is congestion in the system, LMP prices can vary. Where there is no congestion, LMP prices tend to be equal across the system. The relevant system Ali initially analyzed was the entire AEP East Zone which consists of transmission facilities of ten operating or transmission companies including Ohio Power, Indiana Michigan, Kentucky, Wheeling

Power, Kingsport and West Virginia Transmission. (AEP Ex. 5, p. 6). Many factors can influence LMP pricing which vary not just hourly but on a five minute basis. These factors include facility changes, load changes, re-dispatch, and power transactions. (AEP Ex. 5, p. 7).

Mr. Ali employed the PROMOD model to perform simulations of the PJM region. The model inputs include future demand, generating unit characteristics and transmission constraints that simulate hourly LMPs rather than the five (5) minute LMPs posted in the real world. Mr. Ali employed a "base case" with an unmodified version of the PJM model and a "study case" which modeled three (3) new projects - one wind and two solar with a combined capacity of 650 MW. (AEP Ex. 5, pp. 4-5).

The PROMOD model takes weeks to perform. Mr. Ali accordingly only modeled three years - 2021, 2024 and 2027. (AEP Ex. 5, p. 5, Figure 1).

Mr. Ali agreed that congestion costs vary at the relevant pricing node. Mr. Ali further concluded that there was no congestion - anywhere, any time or any place - in the AEP East Zone. Accordingly, Mr. Ali believed LMP prices would be uniform across the system. (Vol. II, 503-505, 506).

Since LMP prices are determined at the relevant pricing nodes, location of the new generating source is important. (Vol. II, 505). Mr. Ali had to have a specific location of the interconnection in order to model LMP pricing. The specific generating facility is also important to input the load and rate profile. Mr. Ali relied on the load and rate profile and location of the Highland and Willowbrook solar facilities. The assumption Mr. Ali made was that the location and profile of these projects would have similar representative characteristics to the study case model. (Vol. II, 439-440).

Significantly, Mr. Ali assumed that both the Highland and Willowbrook facilities interconnected to the AEP East Zone. If a facility was located in a different zone, modeling could be affected. (Vol. II, 527).

As the hearing progressed, it became apparent that Mr. Ali's assumption that the Highland facility would connect to the AEP East Zone was incorrect. The facility actually connects to the DP&L zone at the 345 kv Stuart-Clinton line. Accordingly, AEP Ohio recalled Mr. Ali on "rebuttal" to correct the LMP analysis to model the Highland project interconnection at the Stuart-Clinton line and to model the expected output at 400 MW. (AEP Rebuttal Ex. 26, p. 2).

It is clear that Mr. Ali knew, or should have known at the time of his original testimony, that the Highland facility would interconnect to the DP&L zone rather than the AEP East Zone. Mr. Ali filed his testimony on September 19, 2018 based on the PROMOD model runs in May, 2018. The PJM Impact Study was submitted October 3, 2018 and produced during discovery on October 24, 2018. That study reflected the Highland interconnection at the Stuart-Clinton line. (IEU Ex. 14; Vol. XII, 2750-2752). Mr. Ali originally testified on January 16, 2019 and testified he was aware of the Highland connection in October, 2018 before he took the stand. However, he did not amend or modify his testimony to reflect the correct location and interconnection. (Vol. XII, 2756-2757).

Contrary to Mr. Ali's testimony, changing the location of the interconnection and the load output does impact Mr. Ali's calculation of LMP savings. This is demonstrated by a comparison of Figures 1 and 2 in Mr. Ali's Rebuttal Direct. Figure 1 reflects the LMP savings in his original testimony.

Figure 1

AEP Zone	2021	2024	2027
LMP Savings ($/MWH)	0.50	.043	.062
Average Energy Use (GWH)	133,952	136,721	138,989
LMP Savings/Yr. ($/Yr.)	$6,715,561	$5,877,571	$8,599,389

These figures change in Figure 2 which reflects the change in the Highland interconnection point and the 400 MW output.

Figure 2

AEP Zone	2021	2024	2027
LMP Savings ($/MWH)	.053	.053	.068
Average Energy Use (GWH)	133,952	136,721	138,989
LMP Savings/Yr. ($/Yr.	$7,099,456	$7,306,885	$9,398,417

(AEP Rebuttal Ex. 26, pp. 6-7; Vol. XII, 2792).

Re-modeling the PROMOD simulation with changes in input to the Highland interconnection and output at 400 MW does not cure the flaws in the LMP analysis and, in fact, exaggerates the flaws in a number of respects.

First of all, the re-modeled results are suspect. Normally, a complete PROMOD run would take several weeks. This re-run was done in a week and a half. (Vol. XII, 2758). It is apparent that the changes to input were not just the location point but a change in assumed MW output as well. AEP Ohio has failed to prove that the claimed results fully reflect the change in generation output particularly as respects LMP pricing at different nodes and at different hourly or five minute intervals in future years.

Second, the relevant pricing nodes change with the change in location of the interconnection. The power is transmitted now from a new interconnection at the Stuart-Clinton line to a new substation south of the existing Clinton substation. According to Mr. Ali, from that substation, the power is transmitted to the **AEP West Zone** - not the **AEP East Zone** as originally assumed. Mr. Ali testified that the power is integrated into the DP&L power zone and liquidated into the **AEP West Zone**. (Vol. XII, 2779-2780). Mr. Ali performed no analysis of the DP&L system to reflect any changes in congestion at any given pricing node and presents no evidence as to congestion and relevant pricing nodes in the AEP **West Zone**. (Vol. XII, 2784, 2786, 2787).

Third, and most importantly, Mr. Ali's LMP Savings ($/MWH) change in the update for each of the three years projected - 2021, 2024 and 2027. These results were passed on to Mr. Torpey and he had to extrapolate LMP pricing for all intervening years including all future years in the 20 year analysis after 2027. There is no evidence that Mr. Ali passed on the corrected figures to Mr. Torpey or that Mr. Torpey reflected the corrected figures in his analysis. Based on the present record, Mr. Torpey's analysis is based on faulty numbers for 2021, 2024 and 2027.

Mr. Ali's correction of the LMP savings figures for 2021, 2024 and 2027 certainly does not cure any of the flaws in his original analysis.

LMP pricing is only one of the possible ancillary benefits or liabilities associated with the REPA arrangement. Mr. Ali did not review the actual REPAs for either the Highland or Willowbrook facilities and made no assumption as to the contractual point of delivery or allocation of benefits / costs. (Vol. XII, 2776). In a typical REPA arrangement, the buyer assumes the output at the contractual point of delivery and dispatches the power where and how the buyer determines. (Vol. XII, 2779). The typical REPA will allocate ancillary benefits / liabilities at the point of delivery including regulation, frequency, energy imbalance, spinning reserve, capacity benefits or penalties and other ancillary attributes. The REPAs will allocate ancillary benefits, charges or credits between the generator and buyer in some fashion. In this case, AEP has not addressed whether AEP Ohio would be considered the generator for purposes of receipt of LMP pricing payments. Mr. Ali testified:

> Q. For purposes of your limited analysis, did you make any assumption as to what contracting party would bear or receive the locational marginal pricing?
>
> A. (Ali). No. My generic analysis was looking at the impact of LMPs, changes on the entire AEP zone. (Vol. XII, 2788).

For that matter, Mr. Ali's LMP savings analysis does not indicate any need for capacity or energy. (Vol. II, 462). Nor does his analysis take into account any countervailing or offsetting ancillary service costs or credits. (Vol. II, 417). He did not take into account uplift costs (Vol. II, 417, 455), reserve costs (Vol. II, 418-419), capacity performance assessments (Vol. II, 422), or other ancillary service revenue offsets (Vol. II, 429, 446, 447).

As discussed, Mr. Ali furnished AEP Witness Torpey with the LMP savings forecasts for the years 2021, 2024 and 2027. Mr. Torpey was required to "extrapolate" costs savings for the intervening years between 2021 and 2024 and 2024 through 2027, and thereafter for the thirteen (13) years between 2027 and 2024. (Vol. V, 1459). The purported LMP savings is reflected at Table 4 of the IRP. The figures for 2021, 2024 and 2027 were based on Mr. Ali's original Figure 1 which is incorrect. Mr. Torpey does not reflect the corrected figures in Figure 2 in his analysis.

Mr. Torpey's LMP analysis in Table 4 reflects the same incorrect assumption that the Highland project would interconnect with the AEP East Zone. (Vol. V, 1462, 1463). Since the three year figures for 2021, 2024 and 2027 are all wrong, the extrapolation for intervening years is erroneous as well. Table 4 is incorrect and has not been corrected to reflect new figures for the intervening years.

In Table 4, Mr. Torpey applies a load cost with and without renewables to the OPCO Load (GWH). The OPCO Load is based on Column 8 of FTE-D-1 in the LTFR. (AEP Ex. 1, p.

113). Column 8 is Net Energy For Load and includes Total End User Consumption (Column 6) plus Losses and Unaccounted For (Column 7). (Vol. V, 1453-1454). Mr. Torpey offered no explanation for the assumption that LMP pricing would apply to Losses and Unaccounted For Energy. (Vol. V, 1454).

Further, Mr. Torpey offered no explanation for the resultant decline in the Change in Load Energy Cost in Table 4 from $.05/MWH in 2021 to $.02/MWH in 2024 or the change from $.02/MWH in 2021 to $.07/MWH in 2027. After 2027, the Change in Load Energy Cost remained constant at $.09/MWH in 2029 through 2031, increased to $.10/MWH for 2032 through 2034, increased again to $.11/MWH from 2035 through 2037 and remained at $.12/MWH for the balance of the period. (Table 4, JFT-1, p. 20). Mr. Torpey merely assumed a constant rate of escalation in the latter years even though he also acknowledged that Change in Load Energy Costs for years prior to 2027 would be dependent on the make-up of resources in the AEP East Zone for those years. (Vol. V, 1459).

Mr. Torpey did not verify the location of the Highland interconnection and merely assumed the differential would apply consistently throughout the entire AEP East Zone. (Vol. V, 1468-1471). Mr. Torpey also acknowledged that LMP prices would be paid to the generator at the relevant pricing node. He assumed AEP Ohio would buy all 46,000 GWH from the generic projects and would sell the output into PJM and receive the revenues. (Vol. V, 1472-1473). He, like Mr. Ali, did not review the actual REPAs to determine how LMP credits or charges would be allocated between the parties. (Vol. V, 1474).

In any event, Mr. Torpey acknowledged that LMP savings, assuming no congestion, would apply uniformly across the entire AEP East Zone (Vol. V, 1373, 1454-1456). The AEP East Zone is three times larger than the AEP Ohio load. (Vol. V, 1460). Accordingly, Mr.

Torpey acknowledged that LMP savings were a function of system savings and would apply irrespective of whether AEP Ohio entered the REPA contract or secured the output in an alternative arrangement. LMPs are an ancillary benefit not reserved solely to AEP customers and not dependent on the REPA arrangement. (Vol. V, 1374).

OCA Witness Brown criticized AEP's LMP analysis on several bases. First, LMP pricing is not a resource planning tool and does not establish any "need" for capacity or energy as Mr. Ali conceded. (Vol. II, 462). Any viable PROMOD simulation must be based on simulation of the actual project's location, operation, load profile and generation output as opposed to any "generic" analysis. (OCA Ex. 2, REB Ex. 1, p. 39).

OCA Witness Medine also criticized Mr. Torpey's LMP analysis in Table 4. Ms. Medine testified that a .12% difference in the Net Present Value of claimed savings over a 20-year period fails to demonstrate that one scenario is lower in cost than any other. The difference is within the margin of error of the forecasts. A microscopic change in any number of assumptions can impact the outcome. The results are not dispositive of any relative LMP savings. In fact, many of the assumptions in the analysis are problematic. Specifically, the average annual growth in energy costs at 4.5% is inconsistent with other reported costs. (OCA Ex. 3, pp. 18-19).

Based on the flaws addressed above, AEP's analysis of LMP savings (Table 4) should be rejected in its entirety. Mr. Ali's original analysis improperly assumed the connection point would be the AEP East Load Zone. This analysis was subsequently modified to reflect a connection to the DP&L Zone with assumed liquidation of output into the AEP West Zone - not the AEP East Zone. The many errors in the LMP analysis were never corrected in Mr. Torpey's analysis. The analysis constructed by Mr. Torpey is flawed in this respect and many others.

C. AEP's Fundamentals Forecast Is "Fundamentally Flawed".

AEP Witness Bletzacker sponsored AEP's Fundamentals Forecast employed by AEP Witness Torpey as a basis for his generic economic benefit analysis. The Fundamentals Forecast is a natural gas commodity market forecast. It is not intended to be a specific regulatory tool. It is not an exact forecast but merely one indication of the relationship of supply, demand and price relationship over time. (AEP Ex. 11, pp. 2, 3-5). There are four "cases" in the Fundamentals Forecast - the Base Case, the Low Case, the Upper Case and a Status Quo Case. The Status Quo Case assumes no carbon tax burden during the entire forecast period. The Base and other Cases assume a carbon tax burden in 2028 and thereafter. (AEP Ex. 11, p. 4). The most significant assumption in the Base Case is an assumed $15/ton carbon tax beginning in 2028 and escalating at 5% thereafter. (Vol. III, 778).

The record here demonstrates, as found by the Virginia, West Virginia and Texas Commissions in recent cases, that the Fundamentals Forecast is consistently overaggressive and speculative both in the projections of energy cost and PJM market prices. There is no basis for the assumption of a carbon burden in 2028 that dramatically impacts forecasted prices. There is not now, nor is there contemplated in the future, a proposed carbon tax of $15/ton commencing in 2028.

A review of the Fundamentals Forecast reflects significant variation in PJM peak and off peak prices. It also reflects substantially increasing natural gas commodity prices at the Henry Hub between 2018 and 2048, increasing from $2.79/MMBTU in 2018 $9.17/MMBTU in 2048. The review also reflects disparate natural gas prices at the Henry Hub compared to other locations closer to Ohio such as the TCO Pool or the Dominion South Point Pool. The most dramatic impact in the PJM forecasts is the assumed carbon burden commencing in 2028 which increases forecasted energy prices by $11/MWH alone. (Vol. III, 832; IGS Exs. 4 and 5).

A comparison of the Fundamentals Forecast from 2008 through 2018 is also reflected in IEU Ex. 11 and 12. (Vol. III, 841, 855). This comparison demonstrates the speculative nature of the Fundamentals Forecast. In 2018, Mr. Bletzacker forecasted Henry Hub commodity prices at $9.43/MMBTU. That forecasted price proved wildly inaccurate. Based on subsequent forecasts between 2008 and 2018, the forecasted price dropped precipitously each year as follows:

2008 - $9.43/MMBTU
2009 - $7.09/MMBTU
2010 - $6.64/MMBTU
2011 - $6.32/MMBTU
2013 - $6.12/MMBTU
2015 - $5.40/MMBTU
2016 - $4.89/MMBTU
2018 - $3.22/MMBTU

(Vol. III, 859-861).

OCA Witness Medine reviewed AEP's assumptions for natural gas prices compared to EIA's 2018 Annual Energy Outlook. Ms. Medine concluded that AEP forecast prices for natural gas at the Henry Hub were substantially greater than EIA forecasted prices. Further, Marcellus Shale gas, produced locally, currently trades at a negative basis differential to Henry Hub. (OCA Ex. 3, p. 20-21, Table A-1).

OCC Witness Lesser also testified that AEP's forecast price at the Henry Hub varied between 2.5% and 18% higher than the EIA 2018 Annual Energy Outlook Agreement. For the entire period of 2018 through 2048, AEP's forecasted prices averaged 12% higher than for EIA forecasts. (OCC Ex. 18, pp. 43-44). Moreover, assuming a differential of $.76/MMBTU between the AEP and EIA forecast and a 10,000 MMBTU/kwh average heat rate, the differential between the AEP gas forecasts and the EIA gas forecasts translates to a $7.60/MWH price differential. (OCC Ex. 18, p. 46).

IGS Witness Paul Leanza also found that the AEP Fundamentals Forecast consistently overstated natural gas prices. (IGS Ex. 13, pp. 3, 5). For example, by 2030, AEP's natural gas estimate is $6.479 while market forecasts the price at $3.389, half AEP's forecast. Based on heat rate correllation, the price difference translates to an over inflated power price of $29/MWH in 2030. (IGS Ex. 13, pp. 5-6). IGS Witness Leanza testified that Mr. Bletzacker's forecasts have been consistently overstated. Based on testimony in Case No. 14-1694-EL, Mr. Bletzacker consistently overstated natural gas prices compared to the Henry Hub:

	Bletzacker	**Henry Hub**
2017	$6.01	$3.37
2018	$6.12	$3.46
2019	$6.19	$3.56
2027	$8.04	$4.65

(IGS Ex. 13, pp. 8-9).

D. AEP Ohio's "Generic" Economic Benefit Analysis Is Skewed To Favor Renewable Resources, Is Based On Unfounded Assumptions And Is Speculative.

AEP Witness Torpey sponsors Exhibit JFT-1 - AEP's Integrated Resource Plan. The IRP includes an analysis of the Net Cost of Energy based on an assumed addition of 400 MW of solar and 250 MW of Wind for a total of 650 MW new capacity. Mr. Torpey merely assumes that this analysis can be extrapolated to 900 MW of renewables resources. The analysis for solar is presented in Table 5 (JFT-1, p. 21) and the analysis for wind is presented in Table 6 (JFT-1, p. 23). The methodology for both sources is identical. Given that the present application requests approval for REPAs for two solar projects, the discussion that follows will focus on Table 5. Table 5 (JFT-1, p. 21) is reproduced below.

Table 5. Generic Solar REPA Benefits

Net Cost of Energy
Generic Solar (400 MW)
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change in Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	($/MW-Day)	(MW)	($M)	($M)	($/MWh)
2021	0.9217	400	813.9	23.2%	45.00	36.6	37.8	(30.8)	50.8	76.0	(1.4)	4.4	5.46
2022	0.8495	400	809.9	23.1%	45.00	36.4	39.2	(31.7)	30.1	76.0	(0.8)	3.9	4.77
2023	0.7829	400	805.8	23.0%	45.00	36.3	40.5	(32.7)	44.2	76.0	(1.2)	2.4	2.95
2024	0.7216	400	803.3	22.9%	45.00	36.2	41.8	(33.6)	58.7	76.0	(1.6)	0.9	1.18
2025	0.6650	400	797.8	22.8%	45.00	35.9	43.0	(34.3)	73.6	76.0	(2.0)	(0.5)	(0.60)
2026	0.6129	400	793.8	22.7%	45.00	35.7	44.0	(34.9)	88.9	76.0	(2.5)	(1.7)	(2.09)
2027	0.5649	400	789.8	22.5%	45.00	35.5	44.6	(35.2)	104.7	76.0	(2.9)	(2.6)	(3.29)
2028	0.5207	400	787.4	22.4%	45.00	35.4	55.6	(43.8)	120.9	76.0	(3.4)	(11.7)	(14.86)
2029	0.4799	400	781.9	22.3%	45.00	35.2	57.2	(44.7)	137.6	76.0	(3.8)	(13.3)	(17.04)
2030	0.4423	400	778.0	22.2%	45.00	35.0	60.7	(47.2)	154.8	76.0	(4.3)	(16.5)	(21.23)
2031	0.4076	400	774.1	22.1%	45.00	34.8	62.7	(48.6)	172.2	76.0	(4.8)	(18.5)	(23.90)
2032	0.3757	400	771.8	22.0%	45.00	34.7	64.9	(50.1)	190.1	76.0	(5.3)	(20.6)	(26.69)
2033	0.3463	400	766.4	21.9%	45.00	34.5	66.5	(51.0)	208.5	76.0	(5.8)	(22.3)	(29.09)
2034	0.3191	400	762.6	21.8%	45.00	34.3	68.1	(52.0)	227.3	76.0	(6.3)	(24.0)	(31.44)
2035	0.2941	400	758.8	21.7%	45.00	34.1	70.8	(53.7)	246.5	76.0	(6.8)	(26.4)	(34.83)
2036	0.2711	400	756.5	21.5%	45.00	34.0	72.2	(54.6)	266.3	76.0	(7.4)	(28.0)	(36.99)
2037	0.2499	400	751.2	21.4%	45.00	33.8	74.2	(55.7)	286.5	76.0	(7.9)	(29.9)	(39.78)
2038	0.2303	400	747.4	21.3%	45.00	33.6	78.0	(58.3)	307.1	76.0	(8.5)	(33.2)	(44.48)
2039	0.2122	400	743.7	21.2%	45.00	33.5	78.1	(58.1)	328.6	76.0	(9.1)	(33.7)	(45.34)
2040	0.1956	400	741.4	21.1%	45.00	33.4	80.7	(59.8)	350.6	76.0	(9.7)	(36.2)	(48.77)
Present Worth	9.4633					335.1		(389.2)			(33.9)	(88.0)	
Levelized			786.9	22.4%	45.00	35.4	52.3	(41.1)	129.0	76.0	(3.6)	(9.3)	(11.82)

Column Definitions:

B. Present valued to 2021 at 8.5% discount rate.
C. Total nameplate capacity of the REPA.
D. Total estimated energy output of the REPA.
E. Estimated annual capacity factor based on estimated energy, nameplate capacity and hours per year.
F. Projected annual total cost per MWh inclusive of return and ITC.
G. Projected annual total cost = D x F/1000.
H. Weighted average of hourly market price of energy displaced by hourly incremental REPA purchase.
I. Change in revenue requirement due to solar energy impact on market sales/purchases (Column D x Column H ÷ 1000).
J. Based on 2018 H2 AEP Fundamental Forecast - Base Case
K. Based on 5 percent (wind) or 19 per cent (solar) PJM Capacity Credit.
L. Column J x Column K x 365 ÷ 1,000,000. Adjusted for leap years
M. Total Change in Net Revenue Requirement is the sum of columns G, I, & L.
N. The net cost of energy for the REPA, Column O x 1000 ÷ Column D

Mr. Torpey's generic analysis is based on Levelized Net Cost of Energy ("LNCOE"). The Net Cost of Energy compares the assumed REPA Contract Price to the avoided cost of energy and capacity from the market. Mr. Torpey uses levelized costs because the Net Cost of

Energy varies year to year due to changes in forecast energy and capacity prices. In addition, wind and solar projects generate energy at different hours of the day which influences the value of the avoided cost of energy (AEP Ex. 14, pp. 7-8). Hourly market prices were based on the Base Case Fundamental Forecast provided by Witness Bletzacker. (AEP Ex. 14, p. 8).

The analysis assumes a fixed REPA over a twenty (20) year term. Investment Tax Credits and Production Tax Credits inure to the owner of the facility and are not otherwise reflected in the analysis. (AEP Ex. 14, p. 9). However, Renewable Energy Credits (RECs) inure to AEP Ohio but are not reflected at all in the analysis. (AEP Ex. 14, p. 10).

The LNCOE analysis is predicated on a variety of factors - the assumed REPA price, the assumed capacity factor, capacity resource, forecasted PJM energy prices and forecasted PJM capacity values. (JFT-1, p. 17). This analysis is extremely speculative and problematic since a change in any one of these input factors changes the results of the analysis. (Vol. V, 1449 and 1450).

Mr. Torpey relies on cost and production data in "RFPs" for 250 MW wind and 400 MW solar projects as well as the U.S. EIA's "Levelized Cost and Levelized Avoided Cost of New Generation Resources in Annual Energy Outlook (2018)". (Attachment 1). The 2018 EIA report is instructive. That report presents an average value of levelized cost for generating technologies entering service in 2020, 2022 and 2040. Wind and solar generating resources are considered "intermittent" resources of little capacity value. Generating units with the capability to vary output to follow demand generally have more value to the system than intermittent units. Accordingly, the LCOE value of dispatchable and non-dispatchable technologies must be carefully compared. The report concludes that direct *comparison* of LCOE across technologies can be *problematic* and *misleading* as a method to assess economic competitiveness of generation alternatives because projected utilization rates, the existing resource mix and capacity values can all vary dramatically across regions where new generation capacity may be needed. (Attachment 1, p. 2).

The EIA Report also found that tax Credits can also significantly impact an LNCOE analysis. The current Production Tax Credit for wind is $24/MWH and $12/MWH for solar. The PTC applies for the first ten (10) years then declines in subsequent years. The ITC for solar begins at 30% and declines in subsequent years. (Attachment 1, p. 2). These tax credits have significant impact in comparing LCOE for conventional resources compared to wind and solar. (Attachment 1, p. 5).

Further, the duty cycle for wind and solar is not operator controlled but is dependent on weather and sunlight and will not correspond to operator controlled duty cycle. Therefore, LCOE for wind and solar is not directly comparable to other dispatchable technologies. (Attachment 1, p. 3).

In Table 5, Mr. Torpey starts with a nameplate capacity of 400 MW for a "generic" solar facility - rather than the 300 MW Highland project and the 100 MW Willowbrook project. (Col. C). Mr. Torpey conceded that a 400 MW "generic" facility could produce different results than separate 100 MW and 300 MW facilities. (Vol. V, 1477). Mr. Torpey then assumes a total estimated energy output of the generic 400 MW project. He applies an estimated annual capacity factor for a generic 400 MW facility which begins in 2021 at 23.2% and then declines thereafter through 2040. (Col. E).

The critical assumption is an assumed fixed REPA Contract Price of $45/MWH for the entire term of 20 years. (Col. E). The Solar Total Cost is the product of Column D times Column F (the assumed Fixed REPA Cost). (Col. DXF 1000). This fixed REPA Contract Price was simply based on an assumption of what a generic REPA could cost. It was not based on the REPAs at issue. Market REPAs could result in REPA prices more or less than assumed. (Vol. V, 1478, 1481).

While Mr. Torpey assumes a fixed REPA Contract Price of $45/MWH, he conceded that Solar REPA prices are declining and future REPA prices may be less than $45/MWH. (Vol. V, 1332). Mr. Torpey never actually reviewed the RFP's for any proposed facility. (Vol. V, 1414). As it turned out, the representative projects included the Highland and Willowbrook projects but he didn't verify the specific load curve or projected output for these facilities and merely assumed a load curve for a single facility would apply to the entire 400 MW generation facilities. (Vol. V, 312, 1316, 1420).

To determine Avoided Energy Cost, Mr. Torpey first determines Solar Energy Priced at Market (Col. H) which is the weighted average of the forecasted hourly market price of energy. That figure is projected to increase from $37.8/MWH to $80.7/MWH in 2040. That figure was based on a presumed load curve for a generic REPA. (Vol. V, 1481-1482). Significantly, the price is assumed to escalate by $11/MWH in 2028 due to the so-called "carbon burden" addressed by Bletzacker' s Fundamentals Forecast. (Vol. V, 1482). The price jumps from $44.6/MWH in 2027 to $55.6/MWH in 2028 and escalates by 5% per year thereafter. The Avoided Cost of Energy (Col. I) is the product of Column D x Column H / 1000.

To determine Avoided Capacity Cost, Mr. Torpey applies the Fundamentals Forecast - Base Case to determine Capacity Prices in $/MW-Day (Col. J). That Base Case Forecast of PJM capacity prices escalate from $50.8/MW - Day in 2021 to $350.6 / MWH - Day in 2040. Mr. Torpey had to rely on the Base Case Fundamentals Forecast to determine market capacity prices because PJM does not forecast capacity prices more than three years out. (Vol. II, 1499 - 1450).

Mr. Torpey then assumes a Solar Capacity Credit of a flat $76.0/MW (Col. K) based on an assumed 19% solar PJM Capacity Credit. Mr. Torpey did nothing to confirm the 19% capacity figure. (Vol. V, 1485). The Solar Capacity Credit Value (Col. L) is the product of Column J and Column K. The Credit Value is presumed to escalate from $1.4 million in 2021 to $9.7 million in 2040.

Finally, the Total Change in Net Revenue Requirement (Col. M) is the sum of Columns G, I and L. The Net Cost of Energy (Col. N) is then determined in $/MWH. Mr. Torpey merely assumed that AEP Ohio could sell 100% of the capacity and monetize the capacity value in the market. He is assuming a capacity credit only and does not attempt to determine any capacity performance penalty or assessment. (Vol. V, 1486).

The Break Even for the 400 MW "generic" solar resource is displayed in Table 7 (JFT-1, p. 23). The Break-Even for solar is $56.82/MWH. Solar will operate at a Net Energy Cost Loss for the first seven (7) years from 2021 to 2027 (Col. N).

	Net Cost of Energy ($/MWH)
2021	17.29
2022	16.59
2023	14.77
2024	13.00
2025	11.23
2026	9.73
2027	8.53

Accordingly, AEP Ohio and its customers would incur a $70 million loss before break-even. (Vol. V, 1352-1353).

A similar analysis is performed for a "generic" wind facility of 250 MW. The assumed capacity factor for wind is 31.0% for each year. The assumed Fixed REPA Price is $40/MWH and the Break Even is $48.40/MWH. The generic wind facility will also operate at a Net Cost of Energy Loss for the first seven (7) years. (Table 8, JFT-1, p. 24 Vol. V, 1487-1489, 1490-1491).

It is apparent from a critical review of Tables 5 and 6 presented in Mr. Torpey's generic Avoided Cost analysis that the analysis is skewed in favor of renewables, is based on numerous unfounded assumptions and is speculative.

First of all, the analysis is based on AEP's Fundamentals Forecast which has been proven to be overaggressive and speculative. Forecasting hourly, let alone real time, energy and capacity values which vary by year, season, day and hour out twenty (20) years is inherently speculative and problematic. Comparing intermittent and baseload resources based on an LNCOE basis with varying load curves, utilization rates and capacity factors is problematic and grossly misleading. Tax credits, including the Production Tax Credit, distort energy and capacity pricing. Mr. Torpey's analysis improperly considers a single 400 MW generic source rather than separate facilities with different load curves, capacity factors and operating characteristics. Again, any of the critical assumptions of the analysis change, the results would change. (Vol. V, 1312).

Mr. Torpey did not consider the potential addition of new generation resources over the next twenty (20) years - including specifically pending or approved solar or wind projects. New generation source could impact the analysis particularly as to assumptions for future energy and capacity market prices. (Vol. V, p. 1448).

Mr. Torpey's analysis incorporates the so-called "carbon burden" engrained in the AEP Fundamentals Forecast which increases the forecasted energy price in 2028 by $11/MWH and escalating at 5% for every year thereafter. (Vol. V, 1333, 1345). That factor alone skews Solar

Energy Priced at Market and the Net Costs of Energy, pushing the Break Even date for solar to at least 2030 and beyond. (See Table 7, Column N).

Worse yet, Mr. Torpey *assumes* that AEP Ohio could sell 100% of the capacity value and monetize the capacity value in the market. (Vol. V, 1317, 1486). The assumption is that if a solar resource is bid and clears the PJM capacity value, some value would be realized. (Vol. VI, 1210). The evidence strongly indicates that solar (and wind) are intermittent sources not likely to be bid or clear the capacity market. Further, there may actually be capacity performance assessment or penalties that apply but were not considered. (Vol. V, 1322, 1342). If no capacity credit is received in the future, the value of Net Avoided Cost of Energy is reduced by $33.9 million. (Vol. VI, 1211).

OCA Witness Dr. Brown reviewed AEP Ohio's generic project analysis. (OCA Ex. 2, REB Ex. 1, pp. 13-17). He also reviewed a specific analysis for the Highland and Willowbrook solar facilities but that analysis has been deferred to Phase II. (REB Ex. 1, pp. 18-24).

Initially, Dr. Brown concluded that assuming the Break-Even for solar at $56.82/MWH and a Break-Even for wind at $48.40/MWH, AEP Ohio expects that the discounted cost of solar power over the next 20 years is approximately 17% higher than wind. (REB Ex. 1, p. 13). AEP Ohio also assumes that a Solar REPA would cost $45/MWH compared to a Wind REPA at $40/MWH. AEP Ohio's own evidence suggests that a Solar REPA is less advantageous than a Wind REPA.

Dr. Brown also concluded based on the Generic Solar Break-Even Analysis (Table 7, Ex. JFT-1), the net cost of energy would exceed market for the first seven (7) years of the analysis. Mr. Torpey projects Avoided Energy and Capacity Costs will increase significantly over the 20 year term. The Net Cost of Energy is lower than market in years 2028 through 2040. The analysis for later years is particularly suspect given increased uncertainty in later years of the analysis. AEP Ohio incorrectly uses the same discount rates for all 20 years of the forecast (based on AEP Ohio current weighted cost of capital). Higher discount rates should have been used in later years given this uncertainty. Just considering inflation, yield curves have significantly different values in the short-term versus longer terms. (REB Ex. 1, p. 15).

Mr. Torpey projects an average annual price increase for Solar Energy Priced at Market of 4.2% over 20 years and an average annual market price increase for Capacity of 12.1% over 20 years. These projections are significantly in excess of historical inflation rates of 2.16% over the last 20 years. In fact, Torpey's projected Capacity price increases are five (5) times the historic inflation rate. (Table 3-1, REB Ex. 1, pp. 15-16).

Further, as discussed, Mr. Torpey merely assumes a fixed Solar REPA Contract Price of $45/MWH over the 20 year term. Mr. Torpey asserts this fixed Solar REPA price provides a hedge against his overly aggressive projections of market capacity and energy prices. AEP Ohio itself projects that solar installation costs for both utility scale and residential and commercial installations will decline through 2030. Recent solar REPA prices have generally been priced in the range of $20 to $30/MWH. Far from being a "hedge", locking in a REPA price over the current market presents an enormous financial risk to AEP Ohio and its customers. (REB Ex. 1-1, pp. 16-17).

Finally, Mr. Torpey's analysis does not reflect "debt equivalency costs". (Vol. V, 1599). AEP Ohio seeks recovery of over $110 million in debt equivalency costs over the twenty year term of the REPAs. However, Mr. Torpey did not factor these debt equivalency costs in his analysis. (Vol. V, 1295). Dr. Brown addresses in his Report the significant impact of debt equivalency costs. This evidence (REB Ex. 1, p. 20) was deferred to Phase II. However, OCA has made a Proffer and urges the Commission to consider the impact of debt equivalency costs in this Phase. The Proffer follows:

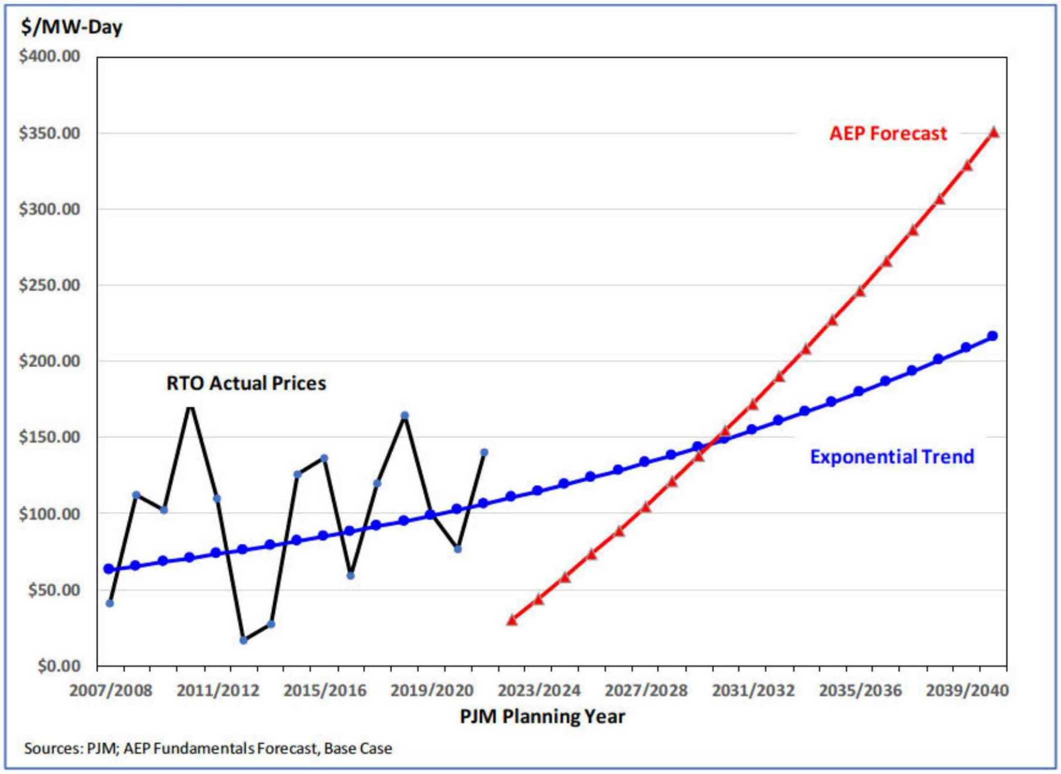
> **PROFFER: AEP OHIO CALCULATES THE ANNUAL DEBT EQUIVALENCY COST TO BE $4.30 MILLION FOR HIGHLAND AND $1.36 MILLION FOR WILLOWBROOK OR OVER $113 MILLION OVER THE 20 YEAR TERM. THE RESULT IS AN INCREASE OF $7.05/MWH FOR HIGHLAND AND $6.69/MWH FOR WILLOWBROOK. THE ADDITION OF THESE COSTS PUSHES BACK THE HIGHLAND BREAK-EVEN BY 16 YEARS AND THE WILLOWBROOK BREAK-EVEN BY 12 YEARS. (REB Ex. 1, pp. 20, 23).**

OCA Witness Medine also criticized Mr. Torpey's Break-Even Analysis. (OCA Ex. 3, pp. 21-24). Most importantly, AEP Ohio fails to consider the risk to ratepayers associated with committing to a 20 year Solar REPA at $45/MWH when all indications are that solar installation costs are declining. This is similar to AEP Ohio's commitment to Wind projects which required AEP Ohio ratepayers to pay higher Wind REC prices through the AER even if REC prices drop. (OCA Ex. 3, p. 21).

Referencing Table 5 of the Torpey analysis, Ms. Medine concludes, as did Dr. Brown, that in the early years of the 20 year term, generic solar energy costs exceed the market. It is only in the later future years do the projects break-even. That is due to Mr. Torpey's overly aggressive projections of future market and capacity price increases. (ESM-3 of OCA Ex. 3, pp. 23-24).

OCC Witness Dr. Lesser expressed similar criticisms of Mr. Torpey's analysis. Dr. Lesser concluded the suggested benefit is overstated and is based on inaccurate future gas prices. He also testified that solar REPA costs must be offset by the claimed debt equivalency costs. Contrary to fact, there is no carbon burden presently and none is contemplated in the future. The presumed carbon burden in year 2028 dramatically impacts projected costs. (OCC Ex. 18, pp. 8, 48). Further, AEP Ohio assumes a capacity credit but ignores probable capacity nonperformance penalties. (OCC Ex. 18, p. 9). Given renewables' intermittent character, there is no assurance that AEP Ohio will be able to collect capacity revenues at all. (OCC Ex. 18, p. 50). AEP Ohio also did not take into account possible FERC actions in Docket No. EL-18-178 to reduce capacity revenues for renewables. (*Id*.). Finally, Mr. Torpey assumes an unreasonable and rapid escalation in PJM capacity and energy market prices. The 2018 Base Case projects market capacity prices increasing at an average rate of 14.6% rising from $30.12/MW day in 2022 to $350.55/MW day in 2040. There is no basis to support this projected price escalation. Based on Dr. Lesser's analysis, the average rate of growth should only be 3.8%. (OCC Ex. 18, pp. 50-54). Figure 4 that follows is from Dr. Lesser's testimony and reflects the discrepancy in Mr. Torpey's analysis.

Figure 4: AEP Capacity Price Forecast vs. Exponential Trend of Actual PJM RTO Prices



In 2048, AEP forecasts a capacity price of $520/MW-day. By contrast, extrapolating the existing exponential trend would result in a capacity price of just over $290/MW-day. AEP's unrealistic capacity price forecast artificially inflates the capacity revenue benefits to AEP Ohio customers in Mr. Torpey's analysis from the REPAs.

OCC Witness Dr. Sioshansi was particularly critical of AEP Ohio's so called "Monte Carlo" simulation. Mr. Torpey testified that PJM historical data yielded a standard deviation of 25% relative to average energy price over the last 10 years. The 25% standard deviation was employed in the probalistc simulation. Accordingly, 66% of the time the value would fail between plus (+) or minus (-) 25% of the mean value. (Vol. V, 1425-1426).

Dr. Sioshansi testified that relying on the prior 10 years of PJM price data was unreliable to calculate standard deviation of future prices since the historical prices were driven by skewed decreases in natural gas prices and in the rate of growth of electricity. Normal distribution (Gausian) does not provide a good fit to historical data in any event. Mr. Torpey did not address autocorrelation in the simulation at all. Normal distribution (Gausian) does not provide a good fit to empirical renewable availability data. The mistaken assumption in Monte Carlo is that random variables such as wind and solar availability are statistically independent. (OCC Ex. 25, pp. 19-22).

IGS Witness Joseph Haugen also agreed that AEP Ohio's forecast of capacity cost benefits was flawed. As discussed, PJM is moving to change capacity market rate changes (FERC Docket EL-18-178) which would only allow state subsidized resources to bid at Minimum Offer Price Rates (MOPR) or capacity would fall under the Resource Carve-Out option. Given the large amount of generation reserves currently in the PJM Market, it is unlikely renewables resources would clear the capacity auction. (IGS Ex. 10, p. 5).

Sierra Club Witness Goggin even acknowledged that the MOPR would effectively prevent state subsidized renewable sources from clearing the capacity market. AEP's REPA proposal may very well result in AEP Ohio not being able to realize sales of renewable capacity. Moreover, there is a risk AEP Ohio would actually be subjected to Capacity Performance assessments (penalties). PJM has recently proposed reducing Wind capacity values from 13% to 7.9% of nameplate capacity. Under PJM Capacity Performance Rates, penalties for under-performance are significant. (Sierra Club Ex. 1, pp. 12-15, 18).

IEU Witness Murray sponsored the 2021/2022 PJM Base Residual Auction Results. These results indicate that, for the most part, Wind and Solar resources are not bid into the capacity market and do not clear the capacity market. (IEU Ex. KMM-2). Out of 8,126 MW of nameplate capacity, only 1,416.7 MW of Wind cleared the market. Out of 1641 MW of Solar nameplate capacity, only 569.9 MW of Solar cleared the market. (IEU Ex. KMM-2, pp. 13-14).

Finally, Kroger Witness Justin Bieber was likewise critical of AEP Ohio's generic benefit analysis. If the Low Band is utilized from the AEP Fundamentals Forecast, there is a loss of $13 million on a NPV bases over the life of the solar REPA and a significant annual loss for the first eight (8) years. (Kroger Ex. 4, p. 18). Again, Mr. Torpey's analysis does not reflect debt equivalency costs which substantially offsets the projected savings. (*Id*., p. 19). The real price of a REPA is more expensive in early years and less in later years. AEP Ohio's forecast of avoided cost of energy and capacity in the PJM Market has just the opposite shape. The avoided cost of energy and capacity is lower in early years and increases substantially during later years of the REPA duration. There is a misalignment between the REPA fixed price and the avoided cost of energy and capacity results. (*Id*., p. 23).

In short, the overwhelming evidence demonstrates that AEP Ohio's "generic" economic benefit analysis is skewed to favor renewables, is based on unfounded assumptions and is speculative. The analysis should be rejected.

E. The Navigant Survey Is Irrelevant To The Issue of "Need" And Ridiculously Biased.

The Navigant Survey is irrelevant to the issue of "need" under R.C. 4928.143(B)(2)(c). The Survey is biased and cannot be extrapolated to reflect "wants" or "desires" of the AEP Ohio residential or commercial customer base.

The survey was sent to only AEP customers with email addresses. (Vol. III, 562). The survey did not accurately reflect the nature of the REPAs at issue, negative issues with the REPAs or the potential impacts. Navigant played no role in the sample selection which was conducted by AEP Ohio. Categorization of responses was performed by a single person based on judgment. (Vol. III, 563, 587, 600).

AEP Ohio has over 1.1 million non-PIPP residential customers. The survey was sent to 120,000 accounts. Only 7,498 responded. Accordingly, 92.8% of AEP Ohio non-PIPP residential customers either were not solicited for a response *or* did not bother to respond. Similarly, only 664 small C&I customers responded out of 150,000 customers - 96.75% provided no response. (Vol. III, 634-635, 637).

OCC Witness Dr. Noah Dormady, an expert in survey methods for economic measurement and a professor at Ohio State, concluded that the Navigant Survey was poorly designed and totally unreliable. Given his credentials and experience, his testimony is particularly credible and reliable. Dr. Dormady concluded that the Navigant Survey was biased in multiple ways - Framing Bias, Hypothetical Bias, Social Desirability Bias and likely Selection Bias. Stated Preference surveys notoriously misrepresent true behavior and attitudes. Navigant failed to provide sufficient, credible details concerning coding methodology, sampling method or content framing. There is no basis to suggest that the sample size was sufficient to mitigate bias. (OCC Ex. 24).

OCA Witness Dr. Brown was equally critical of the Navigant Survey. The response rate for Non-PIPP Residential Customers was only 6.2% and only 3.3% for Small C&I customers. Navigant cannot extrapolate results to the total customer base. Only 92.8% of non-PIPP residential customers and 96.7% of the Small C&I customers either were not solicited or did not bother to respond. Non-response bias is a major problematic issue. Further, the nature of the questions and how posed introduce substantive bias in the response. In sum, Dr. Brown concluded that the Navigant Survey was substantially flawed, reflected low response rates, produced significant non-response bias and reflected biased response choices. (OCA Ex. 2, REB Ex. 1, pp. 31-34).

Further, the National Renewable Energy Laboratory has performed an assessment of utility green power programs in 2017. Customer participation rates tend to decrease as participation costs increase. Well over 95% of customers that have the options to participate in green power initiatives chose not to do so. When green power program costs are greater than 1¢ per/kwh, over 98.8% of customers chose not to participate. (REB Ex. 1, pp. 34-35).

OCC Witness Medine, who has survey experience in working with utilities and state Commissions (Vol. VII, 1922-1923), testified that the Navigant Survey actually indicates that customers care more about maintaining bill amounts than having AEP Ohio invest in renewables. Further, Navigant failed to establish the survey results were at all representative of the residential and commercial customer base. The survey was limited to customers with email addresses which were not available for 38% of non-PIPP residential and 65% of Small C&I accounts. The Survey was not directed to the issue of the 20 year risk of committing to a solar or wind REPA or the premium cost and risk that would be incurred. Based on her experience in Alaska, in general only 3% of customers are willing to see an increase in bills with renewables. (OCA Ex. 3, pp. 33-35).

F. The Purported Economic Development Benefits Of The Projects Are Also Irrelevant To The Issue of "Need". Any Economic Development Benefit Would Apply Irrespective of AEP Ohio's Participation In The REPA Contracts.

As discussed above, the Commission has previously held that economic development benefits and job creation are irrelevant to the issue of "need" based on resource planning as provided by R.C. 4928.143(B)(2)(c). See *In The Matter Of the Long-Term Forecast of Ohio Power and Related Matters*, Case No. 10-501-EL-FOR et seq., Opinion and Order at 25-27 (Jan. 9, 2013).

The bottom line is that any economic development benefit of the two proposed solar projects will apply irrespective of whether the projects are developed in the market or through AEP Ohio's proposed commitment through the subject REPAs. (Allen, Vol. I, 105; Buser, Vol. I, Tr. 1088). Further, solar projects exhibit substantial installed costs. Together, the total construction output above for the projects exceed $332,396,000. For 400 MW of solar this equates to $830,990/MW. (Ex. SB/BL-1, Table 1, p. 10). There is no "free lunch". Ultimately, these construction costs will be borne by ratepayers, including the Ohio ratepayers. (Lafayette, Vol. IV, 1141).

As it turned out, AEP Witness Buser played a minor role in the economic development study. He was only responsible for Section V, the socioeconomic portion. Dr. Lafayette was responsible for the bulk of the analysis. (Buser, Vol. IV, 1115-1116).

On cross-examination, Dr. Lafayette conceded that "many" benefits associated with job commitment would be separate and in addition. He did not eliminate any double-count in his analysis. (Vol. IV, 1134). Errors were also made in calculating local tax benefit. (Vol. IV, 1139). Dr. Lafayette assumed all direct jobs would be Ohio jobs which may not be the case. (Vol. IV, 1140). Dr. Lafayette further assumed no generation resources in Ohio would be displaced. (Vol. IV, 1140). He addresses no adverse impact on other competitors. (Vol. IV, 1143). He did not consider the impact of probable property tax abatements. (Vol. IV, 1150).

Significantly, Dr. Lafayette acknowledged that the nature of a solar project poses particular challenge. These projects are significantly different from standard construction projects with available construction multipliers. Solar projects must be analyzed based on a line-by-line projection of goods and costs. Particular attention must be devoted to determining whether goods are sourced in Ohio. If not, there is no direct benefit in Ohio. Not only must a line-by-line analysis be made but there has to be a line-by-line determination of the particular source for each line item. (Vol. IV, 1152-1154).

Dr. Lafayette did not review the specific REPA contracts to determine any contractual commitment to source of goods. (Vol. IV, 1152). Instead, he relied on AEP personnel to provide information on costs and source of goods. AEP, in turn, relied on representations from the developers and details were not produced at trial because of confidentiality restrictions. (Vol. IV, 1133, 1136, 1144, 1155). Accordingly, Dr. Lafayette's entire analysis is based on "double hearsay" - unreliable and unconfirmed evidence.

The largest component of a solar project are the solar panels and inverters. The source of these items impacts the entire flow chain from source of manufacture, through transportation to direct installation. (Vol. II, 1154-1155). Dr. Lafayette could provide no details of the breakdown of the total construction costs of $332,396,000 for the projects reflected in Table 1 of Ex. SB/BL-1, p. 10. Dr. Lafayette was not told the number of solar panels or inverters at issue or the specific model or manufacturer. (Vol. IV, 1158). He had no direct communications with the developers. He could not independently verify that the source of the panels/inverters was from Canada, outside the United States or outside Ohio. (Vol. IV, 1160, 1166).

The projects will employ only a few permanent positions during operation. Willowbrook will employ 20 to 24 direct personnel during operation and Highland will employ only 5 new direct jobs during operation. (Vol. IV, 1165-1166). Dr. Lafayette could not address any "premium" for Ohio jobs proposed in the REPA contracts or what the impact might be. (Vol. IV, 1151).

OCA Witness Dr. Brown addressed the economic development benefits analysis. The RIMS II model is heavily dependent on the assumptions made. Actual economic benefit may vary by a factor of ten (10). This analysis should be given little weight. (OCA Ex. 2, REB Ex. 1, p. 25).

Although AEP Ohio suggests that no existing generation sources in Ohio will be displaced, generation output from existing sources will be displaced. Dr. Brown concluded that not recognizing these offsetting economic impacts results in an overstatement of ongoing net economic benefit. Higher electricity rates, including debt equivalency costs of over $110 million, will negatively impact the Ohio economic, reduce sales tax revenue, reduce employment and discourage new businesses from locating in Ohio. Not recognizing these offsets further results in an overstatement of economic benefit. The purported socioeconomic benefits-enhanced living standards, curing the "opioid" crises, enhanced public health benefits and enhanced "gender equality" are overstated and unsupported. These conclusions of benefit are not valid. (REB Ex. 11, pp. 26-29).

VI. CONCLUSION

AEP Ohio has unequivocally conceded that it cannot establish a capacity or energy "need" for the subject facilities under R.C. 4928.143(B)(2)(c) pursuant to this Commission's precedent, that is that based on resource planning projections, generation needs cannot otherwise be more through the competitive market. See *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Office,* PUCO Case Nos. 11-346-EL-SSO et al., p. 39 (Dec. 14, 2011); *In re Long Term Forecast Report of Ohio Power Co.*, PUCO Case Nos. 10-501-EL-FOR and 10-502-EL-FOR (Jan. 9, 2013). The Commission's Staff has independently confirmed that there is no capacity or energy "need" for the renewable energy projects based on integrated resource planning. The competitive PJM Market is more than adequate to service capacity and energy needs.

AEP Ohio's reliance on purported "generic" economic benefits, customer "wants" or "desires", and 'economic development" benefits are wholly irrelevant to the demonstration of "need" based on integrated resource planning as required by R.C. 4928.143(B)(2)(c).

There is no barrier to another affiliate of AEP - AEP Energy, AEP Renewables or another affiliate - to develop renewable energy projects, or other energy generation resources, in the competitive market. AEP is free to develop the projects at its benefit and risk rather than to invoke the limited exception of R.C. 4928.143(B)(2)(c) to force captive customers to subsidize and guarantee the projects.

Since there is no "need" for the projects based on resource planning, the standard that defines "need" under R.C. 4928.143(B)(2)(c), AEP Ohio cannot satisfy the predicate construction under R.C. 4928.143(B)(2)(c) and no nonbypassable surcharge is merited. The case should be summarily dismissed and the relief sought by AEP Ohio denied.

Further, AEP Ohio's proposal to enter into a fixed price REPAs over a twenty (20) year term under the limited exception of R.C. 4928.143(B)(2)(c) is inconsistent with the free PJM competitive market, provides a guarantee and state out-of-market subsidy for the renewable energy projects, distorts the operation of the PJM Market and is anticompetitive.

Finally, AEP Ohio's contorted perception of "need" is self-serving, irrelevant and inconsistent with the predicate conditions of R.C. 4928.143(B)(2)(c). Commissions in three (3) states - Virginia, West Virginia and Texas - have, in the last year, soundly rejected AEP's Fundamentals Forecasts and methodology for asserting claimed cost/benefits of renewable energy projects. Besides being entirely irrelevant to the predicate issues of "need" under R.C. 4928.143(B)(2)(c), this approach has been demonstrated in this case to be flawed, skewed to favor renewable resources, based on unfounded assumptions and speculative.

AEP Ohio's proposal for authority to enter into a fixed price REPA locked in for twenty (20) years term with the attendant, forced nonbypassable surcharge should be summarily dismissed.

Respectfully submitted,

_/s/ John Stock____________________

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CERTIFICATE OF SERVICE

I hereby certify that the undersigned counsel served, or arranged for service of, a copy of the Initial Brief Of Intervenor Ohio Coal Association on counsel for all other parties of record in this case by e-mail, on this 6th day of March, 2019.

/s/ John Stock
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