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**Via E-file**

December 15, 2014

Public Utilities Commission of Ohio
PUCO Docketing
180 E. Broad Street, 10th Floor
Columbus, Ohio 43215

**In re: Case Nos. 14-841-EL-SSO; 14-842-EL-ATA**

Dear Sir/Madam:

Please find attached the BRIEF OF THE OHIO ENERGY GROUP e-filed today in the above-referenced matters.

Copies have been served on all parties on the attached certificate of service. Please place this document of file.

Respectfully yours,

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
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**BOEHM, KURTZ & LOWRY**

MLKkew
Encl.

**BEFORE THE**
**PUBLIC UTILITIES COMMISSION OF OHIO**

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| **In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service** | : | **Case No. 14-841-EL-SSO** |
| **In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20** | : | **Case No. 14-842-EL-ATA** |

# BRIEF OF THE OHIO ENERGY GROUP

## I. INTRODUCTION

The Ohio Energy Group ("OEG") submits this Brief in support of its recommendations in this proceeding. OEG is a non-profit entity organized to represent the interests of large industrial customers in electric and gas regulatory proceedings before the Public Utilities Commission of Ohio ("PUCO" or "Commission"). OEG's members who are participating in this intervention are: AK Steel Corporation, Air Products and Chemicals, Inc., E.I. du Pont de Nemours and Company, Ford Motor Company, GE Aviation, General Motors LLC and Worthington Industries. These companies take electric service from Duke Energy Ohio, Inc. ("Duke" or "Company"). OEG's recommendations are set forth below.

## II. ARGUMENT

### A. The Commission Should Approve a Modified Version of the Price Stabilization Rider

The Price Stabilization Rider ("PSR") would be a credit or a charge to all customers' bills reflecting the net benefits or costs of all revenues accruing to Duke from the sale of its Ohio Valley Electric Corporation ("OVEC") entitlement into the PJM market.[1] The primary function of the PSR is to provide added price stability for customers who are currently 100% exposed to the volatile wholesale market.[2] If market prices increased over the term of the PSR, then the PSR would act as a credit and would help stabilize rates by offsetting the costs of

[1] Company Ex. 6, Direct Testimony of William Don Wathen, Jr. (May 29, 2014) at 11:18-12:2; 13:16-14:8.
[2] *See* Company Ex. 6 at 14:5-8.

the rising market price. If market prices remained low over the term of the proposed Electric Security Plan ("ESP"), then the PSR would likely be a charge to customer bills. So the PSR is a countercyclical hedge that will produce its greatest benefits to customers when they need it most – when PJM market prices are at their highest. On the other hand, when market prices are low and the PSR is a charge, rather than a credit, the cost of the OVEC hedge is easily absorbed by customers, who would effectively pay low PJM market rates for the vast majority of their generation portfolio plus a small charge for the PSR.

Given the substantial amount of testimony devoted to the PSR in this case, it is easy to lose sight of the fact that the financial impact of the proposed PSR will not be very significant. Duke projects that the PSR will be a charge to customers in the first three years of the Rider, before becoming a credit that grows every year from 2019 through 2024.[3] According to Duke's projections, the average annual cost of the charge in the first three years, when the PSR is a charge, is only $7.33 million.[4] This equates to about a 30 cents per month charge for the typical residential household.[5] So the primary issue is not really about the financial impacts of the PSR, it is about Commission policy. OEG believes that it is good public policy for the Commission to modify and approve the PSR in order to maintain some level of state jurisdiction over generation as authorized by the Legislature when it passed Senate Bill 221 in 2008.

**1. Ohio's Law And Legislative Policy Support Continued Commission Jurisdiction Over Generation Supply Through the Establishment of the Price Stabilization Rider.**

From 1911 until 1999, this Commission regulated Ohio's electric utilities in accordance with traditional cost-of-service principles.[6] With respect to generation, the Commission authorized each utility doing business in Ohio to collect a just and reasonable return on the average embedded cost (original cost less depreciation) of its power plant investments, plus the recovery of its actual cost of fuel and other expenses with no mark-up or profit margin. In return, the utility was required to provide reliable and non-discriminatory service to all customers located in its service territory. This regulatory compact allowed the utility low-cost access to the significant amounts of capital needed to build new generation and ensured that new generation would in fact be built. That

[3] *See* OCC Exs. 43 and 43a, Direct Testimony of James F. Wilson (September 26, 2014) at 8:1.
[4] Tr. Vol. XI (November 4, 2014) at 3114:10-21.
[5] Tr. Vol. XI (November 4, 2014) at 3115:12-25 (based on a 1,000 kWh per month typical residential bill).
[6] "*100 Years and Counting: The History of the PUCO*," Public Utilities Commission of Ohio, *available at* http://www.puco.ohio.gov/puco/index.cfm/consumer-information/consumer-topics/puco-history/.

system worked well. Throughout much of the 1970s, 1980s, and 1990s, the electric rates of Duke, and its predecessor companies, Cincinnati Gas & Electric Company and Cinergy were among the lowest in the nation. This in turn led to the growth of energy-intensive manufacturing companies in Duke's service territory, including the members of OEG.

In 1999, however, the Ohio General Assembly fundamentally changed the traditional regulatory compact whereby this Commission established generation pricing for each Ohio utility based upon its individual costs, and instead followed the lead of California and a handful of other states in electing to impose mandatory deregulation. In 1999, Ohio enacted Senate Bill 3, which moved Ohio towards complete reliance on the federally-regulated wholesale power market to provide generation supply.[7] Under Senate Bill 3, after a five-year transition period (2001-2005), the utilities were to corporately separate or divest their generation assets and customers were to rely solely on the wholesale market to supply their energy and capacity needs at just and reasonable rates as determined by the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act.[8]

In the wholesale market, rates are not based on the cost of any given utility, but instead are based on region-wide marginal (incremental) costs. For both energy and capacity, marginal cost pricing pays each supplier the clearing price of the last incremental unit needed to meet region-wide demand. Marginal cost pricing is the basis for market-based pricing. Marginal cost pricing can be beneficial for customers during periods of surplus, such as during a recession when demand is low. But marginal cost pricing can be very detrimental for customers during periods of shortage, such as during the *"polar vortex"* of 2014. Reasonable minds can differ over whether average embedded cost pricing or marginal cost pricing will be lower over the long run. However, there can be little doubt that marginal cost pricing is more volatile.[9]

Midway through Senate Bill 3's five-year transition period, the path toward complete reliance on the federally-regulated wholesale capacity and energy markets became problematic as market prices remained significantly above legacy generation pricing.[10] To avoid the rate shock experienced by Maryland, Illinois, and

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[7] Senate Bill 3, 123rd Ohio General Assembly, *available at* http://www.legislature.state.oh.us/BillText123/123_SB_3_ENR.pdf.
[8] 16 U.S.C. §824d.
[9] OEG Ex. 1, Direct Testimony of Alan S. Taylor (September 26, 2014) at 7; Staff Ex. 1, Direct Testimony of Hisham M. Choueiki, Ph.D (October 2, 2014) at 12:15-17.
[10] *See Ohio Consumers' Counsel v. Pub. Util. Comm.*, 128 Ohio St.3d 512, 513 (2011).

other deregulated jurisdictions,[11] the Commission implemented Rate Stabilization Plans that largely maintained legacy generation pricing for the 2006-2008 time period.[12] Stakeholders then urged the Ohio Legislature to reconsider whether deregulation was in fact the best course of action for the State.

To avert potentially drastic market price increases, new legislation was passed by the Ohio General Assembly in 2008 – Senate Bill 221.[13] Rather than moving Ohio farther toward mandatory reliance on the federally-regulated wholesale energy market, Senate Bill 221 gave the Commission discretion to opt back into some of the traditional features of regulation. For example, under the newly adopted R.C. §4928.143(B)(2)(b), the Commission is authorized to grant an electric distribution utility recovery of a reasonable allowance for construction work in progress for the cost of constructing an electric generating facility or for an environmental expenditure for any electric generating facility, provided the cost is incurred or the expenditure occurs on or after January 1, 2009. And under R.C. §4928.143(B)(2)(c), the Commission can establish a nonbypassable surcharge through which an electric distribution utility can recover costs associated with certain electric generating facilities dedicated to Ohio customers. Both of these tools would not be available to the Commission in a purely deregulated regulatory system.

Senate Bill 221 introduced a hybrid regulatory approach under which a utility could either choose to follow a path toward full reliance on the wholesale market by establishing a Market Rate Offer ("MRO") or could maintain a more state-regulated path by establishing an ESP.[14] When utilities subsequently attempted to establish an MRO, however, the Commission rejected them.[15] Thus, while recent ESP cases have led to Ohio utilities divesting their generation assets and establishing retail Standard Service Offer ("SSO") rates through a competitive bidding process, the Commission still maintains some traditional regulatory tools through Senate Bill 221 that can be used to protect utility customers from the risks and volatility of complete reliance on the federally-regulated wholesale energy and capacity markets.

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[11] *See Id.*

[12] *See e.g.* Opinion & Order, Case No. 04-169-EL-UNC (January 26, 2005); *See also* Opinion & Order, Case No. 02-2779-EL-ATA (September 2, 2003) at 29.

[13] *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 128 Ohio St.3d 512, 513 (2011).

[14] R.C. §§ 4928.142 and 4928.143.

[15] *See* Opinion and Order, Case No. 08-936-EL-SSO (November 25, 2008); Opinion and Order, Case No. 10-2586-EL-SSO (February 23, 2011).

Governor Kasich recently expressed concerns over the status of Ohio's electric regulatory system and questioned the wisdom of heading down the path to full deregulation because it exposes Ohio customers to overreliance on spot markets, stating:

> *I will tell you it is a challenging time in our state that has gone through this whole business of deregulation. Deregulation I think is a challenge for everybody, and the fact that many companies are now shedding themselves of generation and relying more and more on the spot markets, troubles me and concerns me. But this underscores the fact that the ideological definition of deregulation . . . I wasn't sure if it was the smartest thing to have been done in this way, but we are where we are and we can't go back, and so we're onward in a deregulated environment, we've got to figure it out.*[16]

The proposed PSR is supported by Ohio's hybrid legislative system and is a tool made available by Senate Bill 221 that can address some of the Governor's concerns and protect Ohio customers. Under R.C. §4928.143(B)(2)(d), the Commission may approve as part of an ESP:

> *Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service.*

The PSR represents a financial *"limitation on customer shopping"* that has the effect of stabilizing or providing certainty regarding retail electric service, consistent with R.C. §4928.143(B)(2)(d). It is a *"financial"* limitation because customers in Duke's service territory will still procure 100% of their *physical* generation supply either from the market through competitive retail electric service ("CRES") providers or through SSO auctions.[17] As OEG witness Mr. Taylor explained, "*my understanding of... Senate Bill 221 in Ohio was to create a hybrid market and make sure that customers weren't 100-percent dependent upon marginal cost pricing, and the PSR is really in line with that in ensuring there is some avenue for the Commission to try and stabilize prices.*"[18]

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[16] *See* Direct Testimony of James Henning (May 29, 2014) at 5:4-5 (citing Governor Kasich's statement).
[17] Company Ex. 6 at 15.
[18] Tr. Vol. VII (October 30, 2014) at 1875:15-21.

2. **The Price Stabilization Rider Will Provide A Degree Of Stability To Customers Who Would Otherwise Be 100% Exposed To The Volatile Federally-Regulated Wholesale Market.**

Under Duke's proposal, retail customers would essentially receive traditional average embedded cost service from Duke's share of the OVEC generation. The PSR would flow-through to retail customers a credit or charge for the difference between OVEC market revenues and OVEC cost-of-service. Consequently, the PSR would effectively result in all customers paying a price for retail electric generation that is approximately 3% cost-based (from OVEC) and 97% market-based (from the FERC-regulated PJM wholesale market).[19] The 3% of customer bills that is based on the average embedded cost of OVEC is inherently more stable than wholesale market pricing based on the marginal costs of all generators throughout the PJM region. Whether the PSR will result in a charge or credit on customer bills cannot be known with certainty. But the most reliable evidence shows that it will be a charge in the first three years and then a credit thereafter.[20]

The balanced portfolio approach, whereby generation to customers would be priced 3% at cost-of-service and 97% at market, is consistent with the hybrid structure chosen by the General Assembly through Senate Bill 221. Recognizing the risks of complete reliance on the federally-regulated wholesale energy and capacity markets, the General Assembly gave the Commission jurisdiction and tools to continue to protect customers. Those tools support the establishment of the PSR.[21]

It is very important to recognize that the PSR is merely a financial mechanism to stabilize rates. As noted above, all customers would still purchase 100% of their physical generation supply either from the market through CRES providers or through SSO auctions.[22] In other words, no CRES provider is impacted in any way by the approval of this Rider. The PSR would also be neutral in terms of wholesale competition as no wholesale supplier will benefit or be harmed from this proposal.[23] In that sense, the PSR is the best of both worlds: it retains customer choice for generation through the competitive wholesale market, while at the same time providing the stability and reliability of traditional state-regulated pricing.

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[19] *See* OCC Exs. 43 and 43a at 30:1-10.
[20] OEG Ex. 1, Ex. AST-2, line 17.
[21] Adoption of the PSR is also supported by R.C. §4928.143(B)(2)(a) as a cost of purchased power acquired from an Duke affiliate (OVEC) by R.C. §4928.143(B)(2)(e) as an automatic increase or decrease in a component of the SSO price, and by R.C. §4928.143(B)(2)(i) as a provision under which an electric utility may implement economic development. In this case, the PSR furthers economic development by hedging costs that large business customers of Duke would otherwise pay.
[22] *See* Company Ex. 6 at 15:6-15.
[23] *Id.*

The PSR is a valuable tool for achieving a diversified portfolio for Ohio electric customers. Without the PSR, Duke's customers will be 100% exposed to the PJM market. No reasonable investor would invest 100% of his or her assets in a single stock, no matter how well-established and financially sound that stock is perceived to be. A diversified portfolio ensures that the poor performance of any one investment will not unduly harm the investor. Diversifying the generation purchases of Ohio electric customers is reasonable because, unlike many blue chip stocks, the PJM market has proven to be extremely volatile.

While current PJM prices may be low, there is no way to confidently project that PJM prices will remain low in the short term or long term. Coal plant retirements will put upward pressure on capacity and energy market prices.[24] SNL Financial recently reported that electric utilities in PJM, MISO and other reliability regions are expected to retire over 27,000 MW of coal capacity over the next 9 years, with 24,000 MW of that occurring during the next four years. In PJM, 10,400 MW of coal capacity is expected to be retired in just 2014 and 2015.[25] The loss of this supply (along with unknown factors such as increased demand, extreme weather, or any problem associated with shale gas supply, etc.) will cause upward pressure on market prices over the short and long term.

PJM has not been able to provide incentives to generators to build new capacity to take the place of known retirements. On September 25, 2013, former Commission Chairman Todd Snitchler filed comments at the FERC expressing his concerns regarding PJM Reliability Pricing Model ("RPM") capacity pricing.[26] The former Chairman stated his concern that the price of capacity in PJM is too low to incent the construction of new generation.[27] He urged PJM and/or the FERC to take administrative measures to incent the construction of new generation.[28] In sum, PJM capacity prices are so low that regulators are actually asking PJM and FERC to devise a plan that could ultimately raise capacity prices. The low capacity prices currently enjoyed by PJM customers may not be sustainable. Higher RPM capacity prices may be needed in order to incent new generation and greater reliability, but they also mean higher prices for customers that are 100% reliant on PJM for their generation supply. This would increase the value of the cost-based PSR hedge.

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[24] Tr. Vol. VII (October 30, 2014) at 1777:5-10.
[25] OEG Ex. 2, Direct Testimony of Stephen J. Baron (September 26 2014) at 14:11-14.
[26] FERC Docket No. AD13-7-000, Todd A. Snitchler Comments (September 25, 2013).
[27] *Id.* at 9.
[28] *Id.* at 14.

In contrast to the volatile and currently deflated PJM market, the OVEC generation is a stable source of power from facilities that have been recently upgraded with pollution control equipment that will allow them to comply with the upcoming Mercury and Air Toxics Standards. There are no significant capital expenditures expected over the next decade. The forecast of demand charges is relatively flat.[29] So the OVEC hedge will be countercyclical to the market. When the market price is high, the PSR will be a credit. When the market is low, the PSR will be a charge. This would necessarily have a stabilizing impact on customer bills that customers cannot get through "*staggering,*" "*laddering,*" or by signing a long-term, fixed-price contract.

On the energy side, the OVEC units will actually benefit from the impending retirement of coal capacity in the coming years. As over 27,000 MW of coal capacity is retired over the next 8 years,[30] with little or no new coal capacity scheduled to take its place, the cost of coal is likely to be stable particularly in the Midwest where many of these retiring units reside.[31] So while coal plant retirements will put upward pressure on the capacity and energy market prices, the all-in generation costs of fully environmentally compliant coal units, such as the OVEC units, are likely to be at or below market prices in the near future.[32]

As explained above, the Ohio General Assembly has already given the Commission authority to protect customers from overexposure to the PJM market, including the ability under R.C. §4928.143(B)(2)(d) to approve as part of an ESP a financial *"limitation on customer shopping"* that has the effect of stabilizing or providing certainty regarding retail electric service. The Commission should therefore approve the PSR pursuant to R.C. §4928.143(B)(2)(d) in order to provide rate stability to Ohio electric customers and to provide a hedge so that customers are not 100% exposed to marginal-cost market prices, but instead have a supply portfolio that is a balanced blend of market purchases and generation pricing.

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[29] OEG Ex. 1 at 13:12-16

[30] OEG Ex. 2 at 14:11-13.

[31] *See* OEG Ex. 2 at 14:14-17.

[32] OEG Ex. 1 at 13:18-21.

### 3. Commission Staff's Opposition To The Price Stabilization Rider Is Unreasonable Based On The Philosophical Opinion That Ohio Should Continue Down The Path Of Ceding Complete Control Of Energy And Capacity Pricing To PJM.

Commission Staff's opposition to the proposed PSR is based on its view that Ohio has been moving toward deregulation for over a decade and that the PSR would be a step in the opposite direction.[33] Staff admits that this is a purely a matter of policy and is not based on a determination that the Rider will harm customers.[34] In fact, Staff witness Dr. Choueiki stated that even if he were hypothetically certain that the PSR would benefit customers through lower rates and greater price stability, he would still oppose the Rider on philosophical grounds.[35] Staff's objection to the proposed PSR is not based on a determination that the likely costs of the OVEC assets will outweigh the likely benefits.

While Staff may prefer that Ohio move to a system in which the Commission cedes all of its authority to regulate generation pricing to PJM, that is not the path chosen by the General Assembly and it is not a path that the Commission is required to follow. Rather, recognizing the risks of complete deregulation, the General Assembly gave the Commission more traditional regulatory tools to continue to protect customers from the volatility and unpredictability of the federally-regulated wholesale power market. Those tools support the establishment of the PSR.

Staff's objection is also based on a second false premise that rejection of the PSR will result in true competition. But Ohio customers will not be shopping in a fully competitive market, even if Ohio utilities divest all of their generating assets and the PSR is not approved, because PJM is not a fully competitive market. PJM is a regulator that administratively determines capacity rules and capacity prices.

For example, PJM regulates whether demand response and energy efficiency resources are able to bid into the Base Residual capacity auctions, what suppliers are allowed to bid into the wholesale capacity auctions and, most significantly, PJM utilizes a complex model to administratively determine the RPM price.[36] In other words, PJM capacity prices are based on a PJM regulatory formula, not on a purely free market. So Staff is opposed to

[33] Staff Ex. 1 at 17:17-20 *("It took the Commission over a decade to transition all four electric utilities into a competitive retail-market construct. Granting any generation-related riders for Duke Energy Ohio would be a move in the opposite direction").*
[34] Tr. Vol. XII (November 6, 2014) at 3380:16-3381:24.
[35] Tr. Vol. XII (November 6, 2014) at 3380:16-3381:24.
[36] Tr. Vol. XII (November 6, 2014) at 3389:22-3392:7.

the PSR based on the premise that it is a step in the opposite direction from full competition while simultaneously conceding that the PJM capacity market itself is not fully competitive.[37]

Staff's philosophical preference is not good policy for the State. It is not in the best interest of Ohio customers or the Commission itself to cede its regulatory authority entirely to PJM. Ceding authority to PJM and the FERC fundamentally limits this Commission's ability to protect Ohio customers and make decisions concerning Ohio generating assets and retail generation pricing.

For example, if the Commission disagreed with PJM's energy or capacity pricing, the Commission would have to seek a change at PJM or go to the FERC and file a complaint. The Commission would then find itself in the unenviable role of an intervenor at FERC rather than a regulator. Additionally, when Ohio utilities sell their power plants to investment firms or merchant generators, like Duke has done with the vast majority of its Ohio generating assets, the new owner may not have any incentive to work with the State of Ohio on a $CO_2$ State Implementation Plan or to work with the PUCO/State of Ohio to stabilize customer rates if the wholesale market spikes to an extreme level. The State of Ohio has a long and mutually beneficial relationship with Duke and the other Ohio utilities. These are relationships that likely cannot be similarly fostered with institutional investors who may end up owning Ohio's generating assets.

### 4. The Price Stabilization Rider Is A Cost-Based Hedge That Provides A Rate Stability Benefit To Customers That Cannot Be Achieved Through *"Staggering"* And *"Laddering"* The Standard Service Offer Auction Price.

Staff contends that its practice of *"staggering"* and *"laddering"* the procurement of wholesale generation products is sufficient to prevent harmful volatility.[38] In simple terms, staggering and laddering is the practice of splitting up procurements into auctions on different dates and of different lengths in order to achieve a blend of prices.[39] Staggering and laddering are useful tools that ensure that no one auction result can set the SSO price by itself. Although staggering and laddering certainly help mitigate price volatility for non-shopping SSO customers, they are limited by the fact that all of the auction results that make up the blended SSO price stem from the same source – the PJM wholesale market. If the market price is significantly higher than OVEC costs

[37] *Id.*
[38] Staff Ex. 1 at 12:18-13:3.
[39] Tr. Vol. XII (November 6, 2014) at 3476:20-3477:6.

over a long period of time, which it has been in the past, staggering and laddering will not be sufficient to protect customers from high prices. The SSO auction will always track the market price regardless of staggering and laddering mechanisms.

The PSR is a different type of product that protects both SSO and shopping customers. It is a cost-based hedge that is not otherwise available through the SSO auction or through a fixed price contract with a CRES provider, which likewise tracks the PJM market. The PSR is a unique hedge that reflects the difference between the relatively stable OVEC costs and the relatively volatile PJM market.

**5. Approval Of The Price Stabilization Rider Will Not Violate The Federal Power Act Nor Will It Violate The FERC *Edgar* Standards.**

OEG is aware that recent cases arising from efforts in Maryland and New Jersey to incentivize new generation to be built in their regions for the explicit purpose of driving down wholesale capacity prices have found that these actions are preempted by federal law.[40] Both states found that the PJM capacity market clearing prices in their regions were too high because of insufficient generation supply. These states also determined that the annually changing nature of PJM capacity pricing did not provide enough financial certainty for merchant generators to make the large capital investments necessary to construct new generation. Therefore, they decided to take matters into their own hands.[41] In the Maryland case, the Public Service Commission solicited proposals for the construction of a new power plant, offering the successful bidder a fixed, twenty-year revenue stream through a contract that the state would compel local electric utilities to enter.[42] In the New Jersey case, the legislature passed a statute requiring electric utilities to enter into long-term contracts to fund new natural gas-fired plants with generators chosen by the Board of Public Utilities.[43]

The PSR is not remotely similar to the Maryland and New Jersey approaches. While the PSR would allow Duke to recover its OVEC costs and refund its OVEC profits, there are important distinctions between the Maryland and New Jersey cases and the present case. As an initial matter, there is a very important structural

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[40] *PPL EnergyPlus, LLC v. Nazarian*, 974 F. Supp. 2d 790 (D.MD. Sept. 30, 2013), *aff'd* 753 F. 3d 467 (4th Cir. June 2, 2014) and *PPL EnergyPlus, LLC v. Hanna*, 977 F. Supp. 2d 372 (D.N.J. 2013).
[41] *See Id.*
[42] *PPL EnergyPlus, LLC v. Nazarian*, 753 F. 3d 467, 473.
[43] *PPL EnergyPlus, LLC v. Hanna*, 977 F. Supp. 2d 372, 393.

difference between Duke's proposed PSR and the mechanisms struck down in the Maryland and New Jersey cases. In the Maryland and New Jersey cases, the respective state commissions attempted to establish a supplemental wholesale rate. That supplemental wholesale rate represented what the local utility would pay to a third party power plant owner to ensure that the power plant owner fully recovered its costs if PJM revenues were insufficient or what the local utility would receive if the power plant owner's PJM revenues were greater than its costs. No state commission can establish wholesale rates as that is the province of FERC. And the Courts in Maryland and New Jersey so held.

Unlike the Maryland and New Jersey cases, in which the state commissions attempted to establish mechanisms to true-up costs at the wholesale level, the true-up mechanism proposed in this case (the PSR) would function solely at the retail level pursuant to state law. Here, the rate paid by the local utility (Duke) to the third party (OVEC) would be pursuant to a long-standing cost-of-service rate already filed with FERC. Duke, not a third-party power plant owner, would sell its cost-of-service rate entitlement in OVEC into the PJM markets and receive PJM revenues. The difference between Duke's OVEC costs and Duke's PJM revenues would be credited or charged through a retail rate true-up mechanism. The PSR structure presented here does not alter or modify either of the two FERC-filed rates. Nor does it establish a supplemental wholesale rate. The cost-of-service rate paid by Duke to OVEC is unchanged. And the PJM revenues that Duke will receive at the wholesale level are unchanged. The only financial transaction under the PSR occurs at the retail level between Duke and its customers. This transaction is within the Commission's jurisdiction.

Further, in the Maryland and New Jersey cases, the states' efforts were aimed specifically at incentivizing the construction of new power plants that would lower wholesale capacity prices in their region.[44] Even though the RPM capacity prices in the constrained Maryland and New Jersey regions were very high and resulted in high prices for customers, the annually changing nature of RPM capacity prices did not encourage new generation to be built. The states therefore decided to establish their own methods of encouragement (state-subsidized long-term contracts). Providing state-established methods to subsidize the construction of new generation undermined the price signals provided by the FERC-approved RPM market construct.

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[44] Id.; *PPL EnergyPlus, LLC v. Nazarian*, 753 F. 3d 467, 473.

Here, the purpose of the PSR is not to encourage new generation to be built by bypassing the FERC-approved RPM market construct. Instead, the PSR is merely intended to provide rate stability to retail customers by acting as a hedge against market fluctuations at the retail level. Approval of the PSR will not distort the price signals resulting from the PJM wholesale markets. The generation supply bid into the PJM markets will not change if the Rider is approved. Approval of a modified PSR would not cause this Commission to direct how the OVEC capacity or energy would be bid into the PJM wholesale market. OVEC is *existing* generation that Duke previously bid into the PJM wholesale markets, and will continue to bid into those markets, regardless of whether the PSR is approved. Approval of the PSR will not change the wholesale price for energy or capacity at all. Not by a penny.

Additionally, PJM's FERC-approved Minimum Offer Price Rule ("MOPR") does not apply here. The PJM MOPR is intended to address the concern that certain resources seeking to participate in PJM's capacity auctions might attempt to suppress market clearing prices. The PJM MOPR is designed to limit the ability of buyers to suppress capacity prices by subsidizing the construction of new generation. The PJM MOPR only applies to new gas-fired combustion turbines, new gas-fired combined cycles, and new integrated gasification combined cycle units.[45] The PJM MOPR therefore applied to the new gas generation at issue in the Maryland and New Jersey cases.[46] But it specifically does not apply to existing coal resources such as the OVEC units. Therefore, FERC's concerns regarding buyer-side manipulation of the PJM wholesale markets are not implicated by the PSR.

Moreover, unlike the contract costs at issue in the Maryland and New Jersey cases, the OVEC charges or credits sought to be passed through in this case are the result of a wholesale rate that has already been filed at the FERC.[47] The Commission would not alter that FERC-filed rate by approving the PSR.

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[45] *PJM Interconnection, L.L.C.*, 143 FERC ¶61,090 (May 2, 2013) at ¶4 and ¶22 ("*Currently, PJM's MOPR protects against these forms of buyer-side market power by setting a price floor, i.e. a minimum bid, and requiring all new, non-exempted resources to bid at that floor...*"); Id at ¶166 (*"We accept PJM's proposal to apply the MOPR to gas-fired combustion turbine, combined-cycle, and IGCC resources. The IMM, FirstEnergy, and Dayton argue that the MOPR should apply to all resource types and that any resource type can be used to exercise market power. We agree with PJM, however, that the MOPR may be focused on those resources that are most likely to raise price suppression concerns.*").

[46] *Id.*

[47] *See Ohio Valley Elec. Corp.*, Letter Order in FERC Docket. Nos. ER04-1026-000, *et al.* (Dec. 13, 2004); *Ohio Valley Elec. Corp.*, Letter Order in Docket. Nos. ER11-3181-000, *et al.* (May 23, 2011).

Finally, the Court of Appeals decision regarding the Maryland scheme expressly limits the scope of its reach. In that case, the Court specifically states *"...it is important to note the limited scope of our holding, which is addressed to the specific program at issue."*[48] Given that the facts and circumstances in this case are vastly different from those at issue in the Maryland and New Jersey cases, those cases do not bar Commission approval of the PSR. In sum, the approval of the PSR will not violate the Federal Power Act nor will it violate the FERC *Edgar* standards.

### 6. The Commission Should Approve Duke's Proposed Price Stabilization Rider Subject To Several Modifications.

OEG supports the PSR in concept, but proposes several modifications to the PSR in order to protect customers and increase the likelihood that the PSR will provide a valuable hedge against the volatility of the PJM market.

First, and most importantly, OEG recommends that 10% of the PSR should be retained by Duke. By ensuring that Duke has skin in the game, its interests and the interests of its customers would be aligned. We would all be in the same boat. This will provide incentives for Duke to keep OVEC costs as low as possible and revenues from OVEC energy and capacity as high as possible. The remaining 90% would appear as a credit or a charge on Duke's customer bills depending on whether OVEC's all-in generation costs are below or above market prices for any given time period.[49] This modification would make the PSR self-policing and would directly address Staff Witness Dr. Choueiki's concern that Duke would not have sufficient incentive to manage the OVEC assets like its unregulated assets. At hearing, Dr. Choueiki stated that OEG's 90/10 sharing proposal would be an improvement to Duke's proposal if the Commission approves the PSR.[50]

Second, OEG recommends that the term of the PSR should have a definite termination date so that the Rider would start in June 2015 at the beginning of the upcoming ESP and continue through and beyond the next two ESPs before terminating at the end of calendar year 2024 – approximately 9 and a half years.[51] According to OEG witness Alan Taylor, a 9 and a half year PSR duration is an ideal time frame because it is long enough to increase the

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[48] *PPL EnergyPlus, LLC v. Nazarian*, 753 F. 3d 467, 478 (4th Cir. June 2, 2014).
[49] OEG Ex. 1 at 21:31-19.
[50] Tr. Vol. XII (November 6, 2014) at 3398:9-11.
[51] OEG Ex. 1 at 18.

likelihood that cumulative OVEC net benefits would be roughly neutral or positive given market projections, and short enough to likely avoid future exposure to unknown risks such as higher-than-expected $CO_2$ costs, should federal regulations be enacted in this area.[52] The U.S. Environmental Protection Agency's June 2, 2014 proposed Clean Power Plan for reducing $CO_2$ emissions from existing fossil power plants would not become fully effective until 2030, thus subjecting customers to virtually no $CO_2$ cost exposure under a 9 and a half year PSR (8 and a half years of actual hedging, plus a one-year true-up).[53] This time frame would also be consistent with the PSRs and tolling-type of hedge products that are common elsewhere in the country and would increase the likelihood that cumulative OVEC net benefits would be positive.[54]

Third, OEG proposes that the PSR employ a levelization mechanism that would flatten the PSR. The proposed levelization approach would advance the long-term benefits of the Rider and bring the Rider closer to a market-neutral hedge in all years.[55]

Finally, large customers that have corporate finance departments that already deal with commodity, interest rate, or currency exchange rate hedges should have the option to self-insure. Any customer with more than 10 MW of load per single site should be given the chance to self-insure and not participate in the OVEC hedge. This would be a one-time election at the very beginning. Such customers would either be in or out of the hedge for the entire 9 and a half years. The percent of load for any customers who chose not to participate would be added to Duke's 10% share. Thus, the rest of the customer base would not be affected (either positively or negatively) by any self-insurance decisions on the part of large customers.[56]

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[52] OEG Ex. 1 at 18:3-19:5.
[53] Environmental Protection Agency, June 2, 2014 Carbon Pollution Emission Guidelines For Existing Stationary Sources: Electric Utility Generation Units, RIN2060-Ar33.
[54] OEG Ex. 1 at 18:3-18.
[55] OEG Ex. 1 at 19:7-20:12.
[56] OEG Ex. 1 at 21:21-22:10.

## B. The Commission Should Require Duke To Continue An Enhanced Version Of Its Large Customer Interruptible Load Program Beyond May 31, 2015.

Duke's current large customer interruptible load program was established as a result of the Commission's approval of the Stipulation in Duke's last ESP proceeding.[57] Under that program, transmission voltage customers, whether shopping or non-shopping, with loads in excess of 10 MW at a single site can nominate any part of their load as being subject to interruption by Duke.[58] In exchange for subjecting their load to interruption, customers receive an interruptible credit equal to 50 percent of the PJM Net Cost of New Entry ("CONE"), which currently translates into roughly $4.88/kW-month.[59] There are four customers participating in the Company's large customer interruptible load program, representing about 52 MW of interruptible load, although the program is open to up to 250 MW of interruptible load.[60] The costs of the large customer interruptible load program are currently recovered through Duke's Economic Competitiveness Fund Rider (Rider DR-ECF).[61]

In this case, Duke seeks to completely abandon its large customer interruptible load program as of June 1, 2015 - the initial date of its proposed ESP.[62] The Company's first rationale for abandoning the program is that the Company will no longer be a Fixed Resource Requirement ("FRR") Entity in PJM as of June 1, 2015 and therefore will not need the interruptible resources to meet its FRR obligations.[63] Duke's second rationale is its belief that the value of the interruptible resources in its service territory should be determined by PJM and not by this Commission.[64] As discussed below, both of Duke's rationales for terminating its large customer interruptible load program are flawed and do not provide sufficient basis to forego the potential benefits of the program through the ESP period.

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[57] OCC Ex. 2, Stipulation and Recommendation, Case No. 11-3549-EL-SSO (October 24, 2011); OMA Ex. 2, Opinion & Order, Case No. 11-3549-EL-SSO (November 22, 2011).
[58] OCC Ex. 2 at 32.
[59] OCC Ex. 2 at 33; Tr. Vol. VIII (October 31, 2014) at 2340:16-20.
[60] OEG Ex. 2 at 7:4-6; Tr. Vol. VIII (October 31, 2014) at 2359:7-10.
[61] OEG Ex. 2 at 7:1-2.
[62] Company Ex. 6 at 22:6-23:4; Company Ex. 18, Direct Testimony of James E. Ziolkowski (May 29, 2014) at 8:4-11.
[63] Company Ex. 6 at 22:16-19.
[64] Company Ex. 6 at 22:19-23:4.

### 1. Duke's Large Customer Interruptible Load Program Can Continue to Provide Reliability, Economic, and Energy Conservation Benefits to Customers In The Company's Territory Even After Duke Transitions From a Fixed Resource Requirement Entity To An RPM Entity.

The Company's transition from an FRR Entity in PJM to a RPM Entity as of June 1, 2015 will not alter the value of its large customer interruptible load program.[65] While Duke may not need the interruptible load currently participating in its program as part of an FRR plan after May 31, 2015, under present circumstances, the Company could still bid that load into the PJM RPM market as a capacity resource.[66] And that interruptible load could continue to provide benefits to customers in Duke's service territory if used either as part of the PJM RPM capacity auctions or simply at the state level.[67]

For example, the interruptible load of large customers can be used to reduce strains on the electric grid during peak times, increasing the reliability of the grid.[68] The reliability benefit provided by interruptible load was recently demonstrated during the *"polar vortex"* in January 2014. The extreme cold temperatures occurring at that time caused significant reliability problems for PJM, which was *"particularly hard hit"* by outages and other weather-related reliability problems.[69] In fact, PJM lost *"roughly 40,000 MW of generating capacity"* during the coldest, highest load periods, representing 20% of its total generating capacity.[70] However, interruptible load and other demand response resources were available at that time and helped enable PJM to meet the demands on its system.[71]

Additionally, given pending developments in the electric market, it is likely that interruptible resources will become increasingly useful in maintaining the reliability of the grid. As discussed above, electric utilities in PJM, MISO, and other reliability regions are expected to retire over 27,000 MW of coal capacity over the next 9 years, with 24,000 MW of that occurring during the next four years. In PJM, 10,400 MW of coal capacity is expected to be retired in just 2014 and 2015. More than half of these retirements are AEP East coal units located in Ohio, Kentucky, West Virginia, and Indiana.[72] These retirements will tighten the demand/supply balance in PJM, thus increasing the

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[65] OEG Ex. 2 at 4:2-4.
[66] OEG Ex. 2 at 8:13-16.
[67] OEG Ex. 2 at 8:16-18.
[68] OEG Ex. 2 at 11:23-25.
[69] OEG Ex. 2 at 13:12-16 (citing OEG Ex. 2, SJB-4).
[70] OEG Ex. 2 at 13:18-21 (citing OEG Ex. 2, SJB-4).
[71] OEG Ex. 2 at 13:17-18.
[72] OEG Ex. 2 at 14:11-17 (citing OEG Ex. 2, SJB-6).

value of reliability resources. PJM's own estimates indicate that it could fail to meet its peak load requirements in the winter of 2015/2016 if it faces generator outages, extreme cold, and expected coal retirements at a similar rate as last winter. Heightened concerns over such potential reliability problems recently led PJM to propose a new product known as *"capacity performance"* for its RPM market, which would reward resources that can bolster the reliability of its system.[73]

In addition to reliability benefits, interruptible resources can provide economic benefits by lowering market prices for all customers during peak times and by reducing the need for additional capacity resources to be constructed. Interruptible load programs can also bolster economic development in furtherance of R.C. §4928.02(N) by allowing large customers, who must compete both nationally and internationally, to secure more competitive electric rates in exchange for choosing to take a lower quality of service from their utility. Finally, interruptible load programs can increase energy conservation by reducing the amount of power that would otherwise be consumed during peak times.[74]

The Commission has already recognized the multitude of benefits provided by state-sponsored interruptible load programs. In Case No. 11-346-EL-SSO, the Commission approved AEP Ohio's interruptible program and associated $8.21/kW-month credit, stating:

> *The Commission finds the IRP-D credit should be approved as proposed at $8.21/kW-month. In light of the fact that customers receiving interruptible service must be prepared to curtail their electric usage on short notice, we believe Staff's proposal to lower the credit amount to $3.34/kW-month understates the value interruptible service provides both AEP-Ohio and its customers. In addition, the IRP-D credit is beneficial in that it provides flexible options for energy intensive customers to choose their quality of service, and is also consistent with state policy under Section 4928.02(N), Revised Code, as it furthers Ohio's effectiveness in the global economy. In addition, since AEP-Ohio may utilize interruptible service as an additional demand response resource to meet its capacity obligations, we direct AEP-Ohio to bid its additional capacity resources into PJM's base residual auctions held during the ESP.*[75]

The Commission's rationale behind approving AEP Ohio's interruptible load program also supports the continuation of Duke's large customer interruptible load program during the term of the proposed ESP.

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[73] OEG Ex. 2 at 14:1-6 (citing OEG Ex. 2, SJB-5).
[74] OEG Ex. 2 at 11:25-12:6.
[75] Opinion & Order, Case No. 11-346-EL-SSO (August 8, 2012) at 26.

The multitude of benefits stemming from state-sponsored interruptible programs can be achieved irrespective of whether Duke is an FRR Entity or an RPM Entity in PJM. Hence, it would be unreasonable for the Commission to force customers in Duke's service territory to forego those benefits solely because Duke changed its status as a capacity-providing entity in PJM.

**2. In The Absence of Duke's Large Customer Interruptible Load Program, PJM Pricing May Not Provide Sufficient Incentive For Customers To Subject Their Businesses To Interruptions.**

Duke argues that PJM pricing should determine the value of interruptible resources in its service territory.[76] But PJM pricing may not provide sufficient incentive for customers to subject their businesses to interruptions.[77] The PJM Base Residual Auctions ("BRA") through May 31, 2018 have already occurred. Consequently, over the proposed ESP period, customers with interruptible load could only participate in the PJM incremental auctions. And the capacity pricing resulting from incremental auctions has historically been unpredictable, and often significantly lower than the standard RPM capacity prices produced by the annual BRAs.[78] For example, in delivery year 2014/2015, the BRA resulted in capacity price of $125.47/MW-day. The corresponding prices for the 1st and 2nd incremental auctions were $0.03/MW-day and $25/MW-day. This equates to an interruptible credit of approximately $0/kW-month and $0.76/kW-month.[79]

While the 2015/2016 1st incremental auction produced an RTO price of $43/MW-day and the 2015/2016 recent 2nd incremental auction cleared at $136/MW-day (compared to the 2015/2016 BRA price of $136/MW-day), the recent extreme volatility of the incremental auctions would continue to create a potential barrier to Duke interruptible customers who would no longer have the Duke program available, if there is not a replacement alternative. As OEG witness Baron testified at the hearing, *"the stability of the interruptible credit is an important factor"* in whether large customers will subject their business to interruption.[80] Mr. Baron explained:

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[76] Company Ex. 6 at 22:19-23:4.
[77] OEG Ex. 2 at 8:20-21.
[78] OEG Ex. 2 at 9:6-10 (citing OEG Ex. 2, SJB-2).
[79] OEG Ex. 2 at 9:14-17 (citing OEG Ex. 2, SJB-2).
[80] Tr. Vol. VIII (October 31, 2014) at 2329:20-21.

*I mean, customers --interruptible -- receiving interruptible credit is not just something people line up for a handout. They have to respond and curtail their operation and that requires investments and takes risks. They have to install equipment and do a lot of other changes in order to participate. So stability of the rate is important based on my experience.*[81]

Because of the significant uncertainty regarding the ability of the incremental auctions to provide realistic, economic payments for interruptible load that has been previously committed to the Duke interruptible program, incremental auctions may not provide a realistic substitute for a Duke-specific large customer interruptible load program.[82]

If customers with interruptible load choose not to participate in the PJM demand response programs due to insufficient compensation or unpredictability regarding the level of compensation they would receive, then the potential benefits of that interruptible load to all customers would be lost. Duke's belief that interruptible load should receive only PJM pricing could therefore result in all customers losing the benefits of interruptible resources because such pricing may not provide sufficient incentive for large customers to offer their load for interruption.

**3. The Rationale Behind Duke's PowerShare® Program Supports Continuation of Duke's Large Customer Interruptible Load Program.**

Duke currently has two Commission-approved demand response programs – the PowerShare® program and the large customer interruptible load program. While Duke proposes to abandon the large customer interruptible load program, the Company publicly touts the benefits of its other demand response program, the PowerShare® program. Yet these programs are similar in function and the rationale for preserving the PowerShare® program supports the continuation of the large customer interruptible load program as a complimentary option.[83]

Both the PowerShare® program and the large customer interruptible load program can provide reliability, economic, and energy conservation benefits to customers. In exchange, participating customers receive a credit on their bills. Duke discusses the benefits of its PowerShare® program in the 2014/15 program brochure, stating:

[81] Tr. Vol. VIII (October 31, 2014) at 2329:21-2330:3.
[82] OEG Ex. 2 at 10:4-8.
[83] OEG Ex. 2 at 4:12-16.

*Building new generation facilities is costly, time-consuming and offers no immediate relief. Demand-response programs are the cheapest, fastest, and cleanest way to meet energy demand, while providing our business customers with a way to profit from their energy curtailment.*[84]

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*Participation in PowerShare provides economic and environmental benefits...helps maintain low energy rates by reducing the need for new generation plants. Mitigates electrical emergencies, increases system reliability and reduces customer inconvenience. Reduces the need to run expensive generation plants during high demand, resulting in lower wholesale market prices and end-user savings...*[85]

These same benefits apply to Duke's current large customer interruptible load program. At the hearing, Duke witness Wathen acknowledged that demand response programs similar to the PowerShare® program, such as the Company's large customer interruptible load program, can provide such benefits:

*Q: Can a demand response program like PowerShare provide reliability benefits?*

*Mr. Wathen: If that customer is willing to take peak at a time PJM asks, then, yes, it would provide benefits.*

*Q: Can a program like Duke's PowerShare program provide energy conservation benefits?*

*A: If it's reducing energy, then it must be giving you energy benefits.*

*Q: Can a program like Duke's PowerShare program provide economic development benefits?*

*Mr. Wathen: I assume that a customer would enter into an arrangement like that for its economic benefits, so I would assume that's an economic development benefit.*[86]

Duke's opposition to continuing its large customer interruptible load program is based in part on a belief that PJM should determine the value of demand response resources.[87] But Duke's PowerShare® program provides Commission-determined compensation for demand response resources. Thus, the existence of Duke's PowerShare® program undermines the Company's argument against continuing the large customer interruptible load program.

While Duke may argue that customers would still have the option to participate in Duke's PowerShare® program if its large customer interruptible load program is completely abandoned as it suggests, there are several reasons to continue Duke's large customer interruptible load program as a complimentary program to the PowerShare® program. As an initial matter, the PowerShare® program, which is part of Duke's current five-year

[84] OEG Ex. 2, SJB-8 at 2.
[85] OEG Ex. 2, SJB-8 at 2.
[86] Tr. Vol. III (October 24, 2014) at 634:3-17.
[87] Company Ex. 6 at 22:19-23:4.

EE/PDR portfolio plan, is only approved to continue through December 31, 2016.[88] If Duke is permitted to completely abandon its large customer interruptible load program, and it does not propose to continue PowerShare® or a similar program beyond 2016, then such a program may not exist during the later portion of the proposed ESP period. In that scenario, the benefits of either program to customers would be lost. The Commission should foreclose this possibility by approving the continuation of the large customer interruptible load program throughout the entire ESP period.

Continuing a large customer interruptible load program in Duke's service territory also provides more options for customers who are able to subject their business to interruptions and greater incentive for customers to do so. As discussed below, OEG recommends that the Commission enhance the large customer interruptible load program during the proposed ESP period by modifying the terms of participation such that customers are subject to unlimited emergency-only interruptions throughout the year. The PowerShare® program only requires interruptions during the summer months.[89] Hence, the enhanced large customer interruptible load program would serve as a complimentary option for customers who can subject their customers to interruptions year-round. And because customers would receive a slightly greater incentive for doing so (50 percent of Net CONE, currently around $4.88/kW-month, versus the $3/kW-month credit offered by the PowerShare® program),[90] customers will be more likely to participate.

By approving the enhanced version of Duke's large customer interruptible load program to continue throughout the proposed ESP period, the Commission would also provide other customers in Duke's service territory the opportunity to receive greater potential benefits throughout the year at the same price they currently pay for benefits during the summer months. And the cost of providing such additional potential benefits year-round is reasonable, as OEG witness Baron discussed at the hearing:

> *Q. Okay. Let's use -- 4.88 [the large customer interruptible load program rate credit] minus $3 [the PowerShare® rate credit] is a $1.88 -- a $1.88 a kW a month difference under the large interruptible programs versus the PowerShare program, correct?*
>
> *A. Correct.*
>
> *Q. Times 52,000 kW participating in the current Commission-approved large industrial program?*
>
> *A. Yes.*

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88 *See* Opinion & Order, Case No. 13-431-EL-POR (December 4, 2013) (approving the programs contained in the Company's April 15, 2013 Application, as amended on May 9, 2013, including the PowerShare® program).
89 OEG Ex. 2, SJB-8 at 6.
90 *Id.*

*Q. Times 12 is $1.173 million more money credit for the large industrial – large interruptible program versus the PowerShare program?*
*A. Yes. And, of course, it's important to recognize that the program for that extra money there is unlimited annual emergency interruptions.*

*Q. So for the extra $1.2 million you get 52 megawatts of year-round interruptible polar vortex protection versus summer only under the PowerShare.*

*A. Yes, exactly.*[91]

**4. Continuing State-Sponsored Interruptible Programs Is Particularly Important Given That The Legality of PJM-Administered Demand Response Programs Is In Serious Question.**

In light of a recent decision by the D.C. Circuit Court calling into question whether PJM will be permitted to continue allowing demand response resources to participate in its energy and capacity markets,[92] it is critical that the Commission retain a state-administered interruptible load program in order to preserve the benefits offered by interruptible resources. In that decision, the D.C. Circuit Court stated that *"[d]emand response—simply put—is part of the retail market. It involves retail customers, their decision whether to purchase at retail, and the levels of retail electricity consumption."*[93] The Court vacated FERC Order 745, limiting PJM's ability to regulate demand response in its energy markets.[94] Shortly thereafter, FirstEnergy filed a complaint, which is pending now, arguing that PJM should not include demand response in its capacity markets.[95]

The PJM Independent Market Monitor ("IMM") also raised a serious question regarding the continuation of the PJM demand response program in the capacity market. In his comments submitted in response to PJM's proposed performance standards, the IMM stated as follows:

> *The capacity market should no longer include any demand side resources on the supply side of the market, including energy efficiency resources (EE). Demand side resources should be on the demand side of the market where they can and should be a very significant component of the capacity market. PJM needs to take clearly defined steps to facilitate such demand side participation. Load that does not want to pay for capacity and is willing to interrupt its use of capacity when that capacity is needed by those who do pay for it, should be able to avoid paying for capacity. That is the demand side of the market as it should work and can work.*[96]

[91] Tr. Vol. VIII (October 31, 2014) at 2366:1-18.
[92] *Electric Power Supply Association v. Federal Energy Regulatory Commission*, D.C. Circuit Case No. 11-1486 (May 23, 2014).
[93] Id. at 11.
[94] Id. at 16.
[95] Tr. Vol. VIII (October 31, 2014) at 2333:7-10; *See* FERC Docket No. EL14-55.
[96] OEG Ex. 2 at 10:20-11:11 (citing Comments of the Independent Market Monitor on PJM's Capacity Performance Proposal and IMM Proposal, The Independent Market Monitor for PJM (September 17, 2014) at 8).

Hence, significant uncertainties currently surround the PJM demand response program. If that program is eventually terminated, then the continued existence of demand response programs in Ohio will be left entirely to the Commission. In anticipation of such a scenario, the Commission should continue to require Duke to provide an interruptible load program in Duke's service territory. Doing so would ensure that the benefits to customers associated with such a program are not lost regardless of the outcome of PJM IMM-recommended changes or court proceedings related to FERC Order 745.

**5. Continuing Duke's Large Customer Interruptible Load Program Would Provide Greater Rate Stability For Interruptible Customers Who Currently Base Their Planning And Operations On Participation In The Program and Would Prevent Economic Disadvantages to Those Customers.**

Providing rate stability to customers is important in light of the uncertainties surrounding Duke's generation service rates throughout the ESP period.[97] In its previous ESP case, Duke agreed to divest its generation assets and to use competitive bidding processes to set its SSO rates.[98] Duke proposes to continue setting its SSO rates through competitive bidding processes during the ESP period proposed in this case.[99] Hence, customers would remain subject to uncertainty and market risk throughout that time. Market prices could fluctuate depending upon natural gas prices, coal plant retirements, proposed environmental regulations (i.e. the U.S. Environmental Protection Agency's Rule 111(d) proposal), events such as last winter's *"polar vortex,"* or other factors.[100] Given the uncertainties and risks associated with Duke's chosen rate-setting approach, the Commission should continue the interruptible load program in order to provide greater rate stability to customers currently participating in the program during the proposed ESP period.

Further, abandoning Duke's large customer interruptible load program would place the Company's large industrial customers in Southern Ohio at a disadvantage relative to similar large industrial customers in the Northern Ohio service territories of the FirstEnergy operating companies. Because customers in those service territories can receive an interruptible rate credit through May 31, 2016,[101] a steel mill in Northern Ohio would potentially have a significant economic advantage over a similar customer in Duke's service territory for a full year. Such an approval

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[97] OEG Ex. 2 at 18:3-6.
[98] OMA Ex. 2 at 11 and 29.
[99] Company Ex. 3, Direct Testimony of Robert J. Lee (May 29, 2014) at 5:3-9.
[100] OEG Ex. 2. at 6:6-9.
[101] Opinion & Order, Case No. 12-1230-EL-SSO (July 18, 2012) at 37.

would therefore result in inequitable treatment for customers in Duke's service territory compared to customers in the FirstEnergy operating companies' service territories.

OEG also notes that the interruptible programs for the FirstEnergy operating companies were approved to continue even though those companies have long been *"wires-only"* companies, having divested their generation in the mid-2000s, and even though they operate as RPM Entities in PJM.[102] The Commission has repeatedly approved FirstEnergy's interruptible program with an associated credit of $10/kW-month to continue despite these facts.[103] Accordingly, the pending divestiture of Duke's generation assets and its change of status to an RPM Entity do not necessitate that Duke's large customer interruptible load program be abandoned. Instead, the Commission should continue a large customer interruptible load program in Duke's service territory in order to maintain consistent policy between the Ohio utilities.

### 6. Rather Than Abandoning Duke's Large Customer Interruptible Program, The Commission Should Approve an Enhanced Version Of That Program To Continue Through the Proposed ESP Period.

Instead of completely abandoning the large customer interruptible program during the proposed ESP period, the Commission should simply modify and expand its terms. Specifically, as discussed above, the Commission should require that participating customers be subject to unlimited emergency-only interruptions throughout the entire year, rather than only in the summer months. The level of the interruptible credit, 50 percent of Net CONE, should remain the same. This modification would provide even greater reliability to other customers, particularly if an event like last winter's *"polar vortex"* occurs during the proposed ESP period, at the same cost as the current large customer interruptible load program. It will also compliment Duke's PowerShare® program, which is only applicable during the summer months, by providing demand response resources throughout the entire year.[104]

The Commission should require Duke to continue recovering the costs associated with any interruptible credits through Rider DR-ECF. Also, Duke should be required to maximize the financial value of the interruptible capacity by bidding it into the appropriate PJM capacity auction and credit that revenue back to

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[102] OEG Ex. 2 at 19:8-9.
[103] Opinion & Order, Case No. 12-1230-EL-SSO (July 18, 2012) at 37.
[104] OEG Ex. 2 at 18:8-22.

customers. This crediting approach was required when the Commission approved the AEP Ohio's current interruptible program.[105]

### C. The Load Factor Adjustment Rider Should Be Phased-Down Rather Than Terminated And Modified To Remove The Small Business Customers. Alternatively, The Commission Should Adopt Staff's Recommendation To Gradually Phase-Out The Load Factor Adjustment Rider.

In Duke's last ESP case, the Commission approved Duke's Load Factor Adjustment Rider ("LFA Rider"), which is a non-bypassable charge and credit designed to stabilize electric service by enhancing some of the benefits received by high load factor customers. Duke's LFA Rider currently applies to customers served under rate schedules DS, DP, and TS.[106] In this case, Duke proposes to immediately terminate the LFA Rider as of June 1, 2015. Duke's rationale is that the price customers pay for all generation-related costs should be established by PJM. Duke states that high load factor customers should be rewarded with appropriate offers by competitive suppliers or in the form of lower SSO rates instead.[107]

The Commission should reject Duke's proposal to immediately terminate the LFA Rider beginning June 1, 2015. Duke did not present any information on the impact of its proposed elimination of the LFA Rider beginning June 1, 2015. Indeed, the typical bill impact analyses presented by Mr. Ziolkowski remove the effect of the LFA Rider from both current and proposed rates.[108] But as Commission Staff witness Donlon explains, if Duke's proposal was adopted, *"the initial rate increase to certain customers would be too high."*[109] Staff provided the following chart which estimates the adverse bill impacts to customers if the LFA Rider were completely eliminated.[110]

<u>Estimated Impacts of Eliminating LFA Rider</u>

| Schedule | Total # of Customers | Approximate # of Customers over 50% LF | % of Total | Est. % Impact on Non-Shop Customers with 83% LF |
|---|---|---|---|---|
| DS | 18,703 | 3,711 | 20% | 12% |
| DP | 273 | 183 | 67% | 11% |
| TS | 34 | 21 | 62% | 15% |

[105] OEG Ex. 2 at 19:14-21.
[106] OEG Ex. 2 at 20:1-9.
[107] Company Ex. 6 at 21:10-22:5.
[108] OEG Ex. 2 at 22:12-13.
[109] Staff Ex. 5, Prefiled Testimony of Patrick Donlon (October 2, 2014) at 3:2.
[110] Staff Ex. 5 at 3:8-9.

### 1. OEG's Recommended Phase-Down and Modification of the Load Factor Adjustment Rider.

In light of the potential rate increases cited by Staff, rather than being completely eliminated as of June 1, 2015, the LFA Rider should be preserved, but gradually phased-down beginning June 1, 2016 such that the demand charge under the Rider is reduced by half at the end of Duke's proposed ESP period.[111] Specifically, in year one of the proposed ESP (June 1, 2015 through May 31, 2016), the LFA demand charge should be maintained at its current level of $8 per kVa of billing demand, though recalculated to remove DS customers. In year two (June 1, 2016 through May 31, 2017), the demand charge should be reduced to $6 per kVa of billing demand. In year three (June 1, 2017 through May 31, 2018), the demand charge should be reduced to $4 per kVa of billing demand. Thus, the demand charge would be cut in half by the end of the proposed ESP period. As the demand charges are reduced, the design of the LFA Rider would also result in decreasing energy credits to maintain revenue-neutrality among all DP and TS customers.[112] FirstEnergy has proposed a comparable approach with regard to a similar rider in its most recent ESP case, although FirstEnergy's approach involves a phase-out rather than a phase-down.

By preserving, but phasing-down the level of the LFA Rider over the proposed ESP period, the Commission can continue some of the LFA Rider benefits to high load factor customers, while easing any adverse impacts of the Rider on other customers. This gradual phase-down approach will provide a reasonable level of time for large, industrial customers – many of whom face significant competitive pressures nationally and internationally – to adjust to what would otherwise be a significant change in their power costs.[113] This approach is also consistent with the ratemaking principle of gradualism since it will soften the harm to high load factor customers who have grown to depend upon the LFA Rider during Duke's current ESP. Further, it will lessen adverse economic development impacts associated with increasing rates on large high load factor customers.[114]

The Commission should also modify the LFA Rider by requiring that the Rider only apply to the approximately 310 customers taking service under Rates DP and TS over the proposed ESP period. This will prevent adverse rate impacts to approximately 19,000 smaller customers currently taking service under Rate DS.

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[111] OEG Ex. 2 at 20:22-24.
[112] OEG Ex. 2 at 21:21-22:8.
[113] OEG Ex. 2 at 21:6-12.
[114] OEG Ex. 2 at 3:19-21.

With this one modification, the Commission could eliminate 98.4% of the customers currently impacted by the LFA from being impacted through the proposed ESP period.[115]

A phase-down and modification of the LFA Rider will provide a more reasonable transition than the Company's proposal to eliminate the Rider immediately beginning June 1, 2015. For example, the impact of eliminating the LFA Rider immediately, as Duke proposes, for an 82% load factor TS customer will result in an immediate rate increase in the range of 14%. Phasing down the LFA Rider, coupled with eliminating DS customers from the Rider, will result in increases of about 8% the first year, 10% the second year, and about 11% in year three of the ESP.[116]

**2. Staff's Recommended Phase-Out of the Load Factor Adjustment Rider.**

Alternatively, if the Commission wishes to eliminate the LFA Rider, than it should adopt the gradual phase-out approach to eliminating the Rider recommended by Staff witness Donlon rather than the extreme method of immediately terminating the Rider as of June 1, 2015 recommended by Duke.[117] Specifically, Staff recommends that the current LFA Rider should be phased-out during the term of Duke's proposed ESP by reducing the Rider by 33% in years one and two, and by 34% in year three, with a true-up to follow for any remaining balance. Staff states that this approach *"will reduce the initial rate impact of those customers receiving a credit for the LFA Rider, while still reducing the cost of those customers that are paying into the LFA Rider."*[118]

While OEG recommends against completely eliminating the LFA Rider, Staff's approach is a reasonable alternative if the Commission chooses to take that path. Unlike OEG's approach, Staff's approach would continue to allow DS customers to participate in the LFA Rider during the proposed ESP period, which would benefit the 3,711 DS customers with load factors greater than 50%. In no event, however, should the Commission choose the *"flash-cut"* approach recommended by Duke in this case, which would force high load factor customers to instantly absorb substantial rate increases beginning June 1, 2015.

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[115] OEG Ex. 2 at 23:1-8.
[116] OEG Ex. 2 at 22:13-18.
[117] Staff Ex. 5, Prefiled Testimony of Patrick Donlon (October 2, 2014) at 2:21-3:3.
[118] Staff Ex. 5 at 4:1-3.

## D. The Commission Should Reject OCC Witness Kahal's Proposal To Do Away With The Practice Of Assigning Standard Capacity Costs To Service Offer Customers Based On Capacity Usage.

OCC witness Matthew I. Kahal proposes to dispense with the well-established practice of allocating capacity costs to the various SSO customer classes according to cost-of-service principles.[119] Mr. Kahal suggests that capacity usage differences should be disregarded and that (save for voltage differences) all SSO customers pay the same bundled energy charge.[120] Mr. Kahal argues that since SSO auction participants do not submit separate bids for capacity, energy, ancillary services, etc., and submit only a bundled *"package"* bid in which the cost of all of these products are factored into a single kWh price, Duke should not unbundle this *"package"* when billing customers for SSO service.[121] Mr. Kahal claims that unbundling the SSO *"package"* is unfair to residential SSO customers, who require more capacity than business customers relative to energy usage. He states that other, non-quantifiable factors such as the larger size of the residential SSO load and the lower migration risk of residential SSO customers justify a policy of ignoring capacity cost-causation.[122]

The Commission should reject Mr. Kahal's proposal for multiple reasons. First, Mr. Kahal's proposal exploits the fact that the SSO auction requires bundled bids in order to create a brand new subsidy for one customer class, to be paid for by the other customer classes. As SSO auction manager, Robert Lee, testified, the SSO auction requires a bundled bid in order to attract bidders and minimize the risk that there will be insufficient interest in one or more of the individual products. Mr. Lee stated at hearing:

> *...[T]here is a lot of different potential auction designs, and there's pluses and minuses associated with each of them. Part of the reason why we like a single product in this is to ensure that there are no products that have limited interest and clear, you know, unexpectedly high prices. We're looking to serve that load – bundled load of SSO – the bundled SSO load of Duke Energy Ohio and that's what bidders are bidding on in this case.*[123]
>
> ***
>
> *And if you break the products up either by customer class potentially or break the product into different components, you run the risk of there being individual components of the auction where there is very little interest and, as a result, a high price.*[124]

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[119] *See* OCC Ex. 32, Direct Testimony of Mathew I. Kahal (September 26, 2014) at 21:15-14.
[120] Tr. Vol. VII (October 30, 2014) at 1760:16-1761:9.
[121] *See* OCC Ex. 32 at 17:5-19:20.
[122] *See* OCC Ex. 32 at 20:1-21:14.
[123] Tr. Vol. II (October 23, 2014) at 320:12-21.
[124] Tr. Vol. II (October 23, 2014) at 321:7-12.

As Mr. Kahal conceded during cross-examination, Duke assigns capacity costs based on the PJM RPM clearing price because the RPM price is the value of capacity in the PJM system.[125] The value of capacity is known in PJM, and each winning bidder is required to provide the specified amount of capacity as a part of serving SSO load. This is a cost incurred by auction winners that is readily quantifiable. Duke is simply requiring each customer class to pay for its share of capacity costs. Mr. Kahal's proposal would socialize capacity costs among all customers and require higher load factor customer classes to subsidize lower load factor customer classes that on average use system resources less efficiently.

Second, Mr. Kahal's argument that the larger size of the residential SSO load and his assumption that residential customers carry lower migration risk justify his proposal to ignore known capacity cost differences between customer classes is extremely speculative. Although it is certainly true that there is more residential SSO load than non-residential SSO load, and it is probably true that residential SSO load carries lower migration risk than non-residential SSO load; how these factors affect SSO pricing is a matter of pure speculation. Mr. Kahal admits that there is no way to quantify the benefits associated with larger size and lower migration risk.[126] In fact, Mr. Kahal does not even establish for certain that residential migration risk is lower. Further, there are other factors, such as greater weather sensitivity, that make the residential SSO load less attractive than non-residential SSO load to bidders. Mr. Kahal does not propose to confer a benefit on non-residential SSO customers for the non-quantifiable factors that weigh in their favor.

Finally, Mr. Kahal makes no attempt to quantify the rate impact of his proposal on non-residential SSO customers. He is asking the Commission to establish an unprecedented allocation methodology in which capacity costs will be socialized among all customers, regardless of size, without even assessing the magnitude of the resultant rate increase on business customers. The Commission should reject Mr. Kahal's proposal on this basis alone.

[125] Tr. Vol. VII (October 30, 2014) at 1755:3-23.
[126] Tr. Vol. VII (October 30, 2014) at 1762:24-1763:3-13.

In sum, Duke, like every other Ohio utility, allocates capacity and energy costs to SSO customers according to well-established, easily quantifiable, cost-causation principles. It does not attempt to quantify the unquantifiable, by allocating costs based on the speculative value of load size, migration risk, weather sensitivity, etc. As such, the Commission should reject Mr. Kahal's proposal to drastically change the methodology for allocating SSO capacity costs.

## III. CONCLUSION

WHEREFORE, for the foregoing reasons, the Commission should adopt OEG's recommendations in this proceeding.

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