BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	Case No. 14-1297-EL-SSO

POST-HEARING REPLY BRIEF OF OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY

PUBLIC VERSION

I. INTRODUCTION

This case, like every electric security plan ("ESP") case, is about establishing a favorable retail rate plan for the future. In this case, the Commission must decide whether the comprehensive electric security plan now before it, including its pricing and all other terms and conditions, is more favorable in the aggregate as compared to the expected results of a market rate offer.

The seventeen parties supporting Powering Ohio's Progress – the Stipulated Fourth Electric Security Plan ("Stipulated ESP IV") filed by the Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (the "Companies") – recognize that Stipulated ESP IV is a comprehensive and prudent retail rate plan. Notwithstanding, those that oppose Stipulated ESP IV now attempt to lull the Commission into a very different vision for Ohio's energy future. Those opposing Stipulated ESP IV ask the Commission to adopt a "wait and see" approach while simultaneously demanding that Stipulated ESP IV be rejected for failing to provide a sufficient guarantee of the market outcome that will result at the conclusion of Stipulated ESP IV. This view is at odds with the nature of ESPs. It also disserves the Companies' customers and inevitably exposes customers to unnecessary and ultimately costly risks.

Contrary to the view put forward by Stipulated ESP IV's opponents, Ohio law and policy do not call for an unbridled embrace of the electricity market for retail electric service. To be sure, Senate Bill 3, enacted in 1999, set Ohio on the road to a more competitive retail electric market. But within the span of five or six years, policy makers saw the risks of a wholly "deregulated" retail market: the vagaries of supply and demand and the volatility of prices. Accordingly, the General Assembly replaced the market-based framework it had previously created with a regulatory framework that applied a basic principle of retail rate management. Ohio legislators rejected the notion that Ohio would put all of its regulatory eggs in one "market" basket. It thus created what might be regarded as the ultimate retail rate stability statute.

Senate Bill 221, adopting that rate stability approach, gave Ohio customers the opportunity to experience the benefits of a competitive market, but the statute also provided important protections against the risks of that market, such as fluctuating retail prices. It encouraged customers to shop, but required electric distribution utilities ("EDUs") to offer a Standard Service Offer ("SSO") as an alternative to the competitive market. Further, the statute required that the SSO be provided in one of two forms: a Market Rate Offer ("MRO") or an ESP. Importantly, the sole criterion of whether an ESP should be adopted is whether, considering its price and all of its terms and conditions, the ESP is more favorable in the aggregate than the expected results of an MRO. Thus, the General Assembly envisioned that ESPs would stand as a mechanism available to customers and would be better than the market. ESPs then may provide stability, certainty and, as the name of the ESP implies, security, which can make an ESP more favorable than an MRO.

Stipulated ESP IV does exactly what an ESP is supposed to do. It provides customers an opportunity to:

- have reliable, reasonably priced electric service;
- enjoy the benefits of market-based pricing and avoid the full effect of market risks;
- enjoy the benefits of economic development; and
- enjoy the wise use of our natural resources through increased energy efficiency, use of renewable power and reduced emissions from power plants.

It also provides protection for those of our citizens who are most vulnerable and at risk. And it is more favorable than an MRO.

The salient features of Stipulated ESP IV include:

- The continuation of the Companies' indisputably successful open, transparent and fair competitive bidding process ("CBP") that employs staggered and laddered procurements to service SSO load.

- The continuation of the Companies' Delivery Capital Recovery Rider ("Rider DCR") that allows the Companies to invest proactively in the distribution system and that has contributed to the Companies' success in achieving among the most favorable reliability records in the state.

- The contemplated continuation of a freeze of distribution base rates.

- The continuation of numerous economic development programs designed to retain, grow and attract industrial and commercial activity.

- The continuation and expansion of funding programs to assist low income customers.

- The introduction of new commitments by the Companies to provide more energy efficiency programs, renewable energy options and carbon emission reductions.

Stipulated ESP IV also introduces the Economic Stability Program, which includes a Retail Rate Stability Rider ("Rider RRS"). Recognizing that all of the Companies' customers receive the benefit of market-based prices, Rider RRS provides protection against fluctuating retail prices. Through a proposed transaction under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), the Companies will purchase from FirstEnergy Solutions Corp. ("FES") all of the output of two of FES's plants (the W.H. Sammis facility ("Sammis") in Jefferson County, Ohio and the Davis-Besse facility ("Davis-Besse") in Ottawa County, Ohio (collectively, "the Plants")), as well as FES's entitlement to Plants owned and operated by the Ohio Valley Electric Corporation ("OVEC"). FES will receive under the transaction an independently negotiated purchase price. The Companies then plan to sell this output into the wholesale market. Through Rider RRS, the Companies' cost (the payments to FES) will be netted against the revenues the Companies receive. Rider RRS will reflect a credit or a charge to customers depending on the relative revenues and costs. Rider RRS is thus designed to run counter to market prices and provide a valuable hedge against market price volatility.

Further, Stipulated ESP IV was not created solely by the Companies; it was the product of open, transparent and lengthy negotiations by the parties to this proceeding, all having the ability to review one of the largest evidentiary records ever to come before the Commission. These parties include the Staff and representatives of customers of every stripe, all agreeing that Stipulated ESP IV meets all of the criteria for approval of an ESP, including that it is something that is the best path forward for customers, the Companies and Ohio.

The briefs filed by those in opposition to Stipulated ESP IV feature a host of allegations and arguments that not only are at odds with Ohio statutes, the precedent of the Supreme Court of Ohio and of this Commission, but also frankly set standards that no ESP could ever meet. A prominent theme of their briefs is that the Companies should present "guarantees" as part of their ESP, and particularly for the results of Rider RRS.[1] Yet, for all of these opponents' advocacy of a reflexive and unwavering support of letting the market "work," it is both ironic and puzzling that the lack of "guarantees" is the linchpin of their opposition.

The fact is, in dealing with markets, there are no and there never will be any guarantees. In dealing with the future, the best one can do is pick the best tools to understand the likelihood of favored outcomes and act prudently to hedge against adverse ones. Even with the given uncertainty of the future, there are a few facts that are not disputed:

1. Energy prices are now at lows not seen for a decade (at least).

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[1] *E.g.*, Sierra Club Brief, pp. 57, 61, 65, 78; Cleveland Municipal School District ("CMSD") Brief, p. 57; Exelon Brief, p. 54; Environmental Law and Policy Center ("ELPC") Brief, pp. 6, 61; Northeast Ohio Public Energy Council ("NOPEC") Brief, pp. 8, 24; Office of the Ohio Consumers' Counsel and Northwest Ohio Aggregation Coalition ("NOAC") (collectively, "OCC/NOAC") Brief, pp. 66-67, 75-76; Ohio Manufacturers Association Energy Group ("OMAEG") Brief, pp. 15, 50; Retail Energy Suppliers Association ("RESA") Brief, pp. 45-47.

2. The nature of the generation fleet is rapidly changing: almost all of the plants that are retiring are baseload coal-fired or nuclear; almost all of the new plants that are coming on line use natural gas for fuel.

3. This change will result in having natural gas prices increasingly set the price for energy.

4. Natural gas prices are among the most volatile of any commodity.

5. Natural gas plants have experienced outages in extreme weather. In the 2014 Polar Vortex, coal and nuclear baseload generation formed the bulwark that ultimately prevented the loss of system reliability.

Thus, in light of these facts, to determine the most reasonable approach presented here, the Commission must judge the quality and thus the weight of the evidence presented by both sides. And in considering the evidence, it is not the number of times an argument is made or the number of parties that make an argument that gives it weight. Rather, the Commission must evaluate the candor, good faith, experience, acceptance and reliability of the witnesses and the methodologies used by the witnesses in coming to their conclusions.

To this end, compare the evidence on the potential outcome for Rider RRS. On the one hand, there is Company witness Judah Rose, one of the most experienced and respected forecasters in the energy field who used some of the most widely accepted computer models to simulate markets and project natural gas, energy and capacity prices, among other things. Using Mr. Rose's forecasts, the Companies projected that Rider RRS would provide a $561 million credit. On the other hand, there are witnesses such as OCC/NOPEC witness Wilson, EPSA/P3 witness Kalt and Sierra Club witness Comings who have virtually no forecasting experience and who did not prepare any forecasts here. These witnesses projected that Rider RRS would cost customers hundreds of millions (and perhaps billions) of dollars using calculations derived from methods of their own devising that have never been reviewed, much less accepted. These same witnesses ignored independent model results (for example, from the U.S. Energy Information Administration) that are unfavorable to their clients or advocate using prices posted in the futures market, even though some of these witnesses (and several others in this case) acknowledge the unreliability of such data for forecasting purposes beyond a few years.

Similarly, compare the evidence of the future of the Plants. On the one hand, there is evidence provided by FES and the Companies showing that the Plants have not been profitable and have required $2 billion in capital infusions. There is also the testimony by FES management – Company witnesses Moul, Harden and Lisowski, all experienced in Plant operations or finances and in making retirement decisions. They provided a frank assessment about the financial viability of the Plants. On the other, there are academic witnesses, such as Dr. Kalt, who have never had any operational or decisionmaking responsibility for generation plants, but nevertheless presented theoretical discussions about economic rationality. They contended that the Plants should stay open if they merely recover their avoidable costs. Yet these witnesses ignored, contrary to common sense and basic business principles, the reality of meager cash flows and unsustainable debt, *i.e.*, no firm can sustain losses indefinitely, even in the face of potentially positive long-term prospects.

Or compare the evidence on the consequences of the closure of the Plants on reliability. On the one hand, there is testimony from Company witness Phillips, an experienced engineer responsible for transmission and system reliability, who presented a study of the effect of the retirement of the Plants on the system. Using a model developed by PJM and run by an independent expert formerly employed by PJM with experience with such models, the study showed serious violations of reliability standards that could only be remedied through transmission system upgrades, costing hundreds of millions to over a billion dollars. And even then, the system's reliability would be, at best, no better than if the Plants had remained in operation. On the other hand, there are witnesses, such as Sierra Club witness Lanzalotta, who presented no study and who apparently prepared his testimony in a handful of days.

Or compare the evidence on the consequences of the closure of the Plants on the economy. On the one hand, there is the testimony by Company witness Murley who presented an economic impact study using IMPLAN, one of the most widely accepted models to assess economic impacts. Ms. Murley's study showed that the retirement of the Plants will adversely affect the region by over $1 billion annually. On the other hand, there are witnesses, such as Dr. Kalt, Mr. Comings, OCC witness Seryak or OMAEG witness Hill, who presented no studies and who, in some instances, failed to properly evaluate the economies of the areas surrounding the Plants, including such basic facts as the identity of the major employers in the areas or the unemployment rate there. Nevertheless, these witnesses opined that the retirement of the Plants would not necessarily have an adverse effect on the local economies surrounding the Plants.

The Commission must review the evidence in regard to whether certain standards have been satisfied. These standards include the statutory ESP approval test, known as the ESP v. MRO test. The Commission must also determine whether Stipulated ESP IV meets each of the three "prongs" of the Commission's stipulation approval test. Per its recent order in the *AEP ESP3* proceeding,[2] the Commission has also indicated that it may review riders, like Rider RRS, considering certain "nonbinding factors."

Like the testimony they sponsor, the arguments advanced by the opponents of Stipulated ESP IV cannot withstand serious scrutiny. For example, regarding the first "prong" of the Commission's stipulation approval test, some argue that there cannot have been any "serious

[2] *In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan,* Case No. 13-2385-EL-SSO, Opinion and Order, pp. 19-26 (Feb. 25, 2015) ("*AEP ESP3* Order").

bargaining" because some of the Signatory Parties received bargains. Under their standard, no stipulation could pass muster.

Stipulated ESP IV's opponents also assert, among other things, that the Commission lacks jurisdiction over wholesale rates and transactions and thus the Commission cannot approve a retail rider, Rider RRS. This overlooks that the proposed transaction is not before the Commission for approval. Nor is the Commission being asked to set wholesale rates. Rider RRS plainly is a retail rate.

Similarly, these parties argue that Rider RRS and other provisions violate various parts of Title 49 of the Ohio Revised Code. Yet, the statute that authorizes ESPs, Section 4928.143, expressly provides that an ESP authorized by that statute may be approved "[n]otwithstanding any other provision of Title XLIX of the Revised Code to the contrary . . . ."

The legal arguments raised by Stipulated ESP IV's opponents relating to the ESP v. MRO test fare no better. OCC/NOAC argue, without any authority, that ESPs should be eliminated outright. Others argue that a quantitative ESP v. MRO analysis should never use estimates, a standard that would be impossible for any ESP to meet given that ESPs necessarily extend into the future. Still others assert that statutory language, Ohio Supreme Court and Commission precedent notwithstanding, the Commission cannot consider qualitative factors in the ESP v. MRO test.

In a case that presents serious issues regarding Ohio's energy future, the opponents of Stipulated ESP IV fail to provide arguments supported by the law or the record. In contrast, there is ample legal and evidentiary authority that underlies Stipulated ESP IV. As the Companies' Initial Brief demonstrated and as the discussion that follows shows, Stipulated ESP

IV represents a sound and prudent approach to providing the Companies' customers outstanding reliable and reasonably priced service for many years. Stipulated ESP IV should be approved.

The parties opposing Stipulated ESP IV have submitted approximately 1,000 pages of briefs. The issues and stakes in this case deserve that the various arguments receive a detailed response. Accordingly, below, the Companies demonstrate in Sections II, III and IV, respectively, that Stipulated ESP IV meets each of the three prongs of the Commission's stipulation approval test. This discussion includes a showing that Rider RRS satisfies the criteria established by the Commission in the *AEP ESP3* proceeding. The Companies then address in Section V how Stipulated ESP IV meets the ESP v. MRO test. This brief concludes in Section VI showing that the Attorney Examiners' rulings challenged by certain intervenors were correct.

II. STIPULATED ESP IV IS THE PRODUCT OF SERIOUS BARGAINING AMONG CAPABLE AND KNOWLEDGEABLE PARTIES

The Stipulations put forward by the Signatory Parties satisfy the first prong of the Commission's often used test for approval of a stipulation. They are "the product of lengthy, serious bargaining among knowledgeable and capable parties in a cooperative process, encouraged by [the] Commission and undertaken by the parties representing varied interests, including the Staff, to resolve the . . . issues."[3]

The bargaining process in this case began even before the Companies filed their Application in August 2014 and continued for approximately 15 months thereafter.[4] In fact, because all Signatory Parties agreed to the Third Supplemental Stipulation after extensive fact-finding – over 3,700 discovery questions, 25 days of depositions, and 35 days of evidentiary

[3] *In the Matter of the Application of Duke Energy Ohio, Inc., for Approval of Proposed Reliability Standards,* Case No. 13-1539-EL-ESS, 2014 Ohio PUC LEXIS 221, at *15 (Sept. 17, 2014).

[4] Companies' Initial Brief, pp. 37-40.

hearings from August through October, 2015, generating over 7,400 pages of hearing transcript – the Commission has likely never reviewed a stipulation where the Signatory Parties have been more knowledgeable than in this proceeding.[5] In their attempt to oppose Stipulated ESP IV, some intervenors invent new tests or interpretations for the first prong of the Commission's stipulation approval test. But these appear to be arguments to be made to make arguments rather than to make sense. They suggest, in turn, that no serious bargaining occurs: (1) where a stipulation includes bargained for benefits to a signatory party; (2) where a side agreement was entered into after the start of the hearing; and (3) incredibly, where a stipulation is reached in an ESP. A mere restatement of these arguments proves their fallacy: in each case, if their view was correct, there could never be – and there never could have been – any stipulation approved in any ESP. These never have been – and never could be – the criteria for satisfying the serious bargaining prong of the Commission's stipulation approval test.

A. Signatory Parties Represent Diverse Interests And Are "Knowledgeable".

There should be little argument that the Signatory Parties represent a diverse set of interests. They include Staff, large industrial customers, a public utility, small and medium-sized businesses, mercantile customers, a Competitive Retail Electric Service ("CRES") provider, an energy management solutions provider, colleges and universities, low-income residential customers, organized labor, and a large municipality.[6] There should also be little dispute that these parties are knowledgeable. Almost all of them have participated in numerous Commission proceedings.[7] Yet, some intervenors argue otherwise.[8]

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[5] *See* Mikkelsen Fifth Supp., p. 8; Third Supp. Stip., pp. 1, 5. Indeed, one intervenor, the Cleveland Municipal School District ("CMSD"), who otherwise opposes the Third Supplemental Stipulation, concedes that this robust and fair process cannot be said to represent anything other than serious bargaining. CMSD Brief, pp. 33-34.

[6] Mikkelsen Fifth Supp., pp. 2-3.

[7] *See, e.g., In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143,*

OCC/NOAC and NOPEC, for example, rely upon witness Kahal's pre-filed testimony to assert that the signatory parties do not represent a diversity of interests.[9] But Mr. Kahal's opinions are baseless, as revealed by his own testimony at hearing. As an initial matter, Mr. Kahal admitted that he had reviewed only one Commission case on the standard for the approval of a stipulation.[10] Mr. Kahal argued that the absence of the OCC/NOAC from the group of signatory parties demonstrates that the Stipulation is not broadly supported by parties representing a diverse range of interests.[11] Mr. Kahal admitted, however, that no stakeholder's interest in the bargaining process is more important than any other stakeholder's interest.[12] He further admitted that neither OCC/NOAC, NOPEC nor any other party should have a veto over the approval of stipulations.[13] Stunningly, Mr. Kahal also admitted that he had reached his conclusion that there was no serious bargaining *without* having *any* information on OCC/NOAC's or NOPEC's involvement in settlement negotiations.[14] And he could not say whether any party was precluded from having the opportunity to participate in the settlement process.[15] In short, Mr. Kahal reached his conclusion with essentially no relevant information concerning the bargaining process that actually took place. Thus Mr. Kahal's views are of little support to OCC/NOAC.

Revised Coded, in the Form of an Electric Security Plan, Case No. 10-388-EL-SSO, Opinion and Order, p. 21 (Aug. 25, 2010) ("ESP II") (indicating that many of the Signatory Parties to this proceeding also participated in ESP II, including OEG, the City of Akron, the Council of Smaller Enterprises, Nucor, Material Sciences Corporation, AICUO, CHA, Kroger, EnerNOC and OPAE); *see also* Staff Brief, p. 4 ("The signatory parties have an extensive history of participation and experience in matters before the Commission.").

[8] *See, e.g.*, OMAEG Brief, pp. 74-77; OCC/NOAC Brief, pp. 34-45; NOPEC Brief, pp. 70-71.

[9] OCC/NOAC Brief, p. 40; NOPEC Brief, pp. 70-71.

[10] Hearing Tr. Vol. XXIV, pp. 4905-06 (Kahal Cross).

[11] Kahal Supp., p. 11.

[12] Hearing Tr. Vol. XXIV, pp. 4906-07 (Kahal Cross).

[13] Hearing Tr. Vol. XXIV, p. 4907 (Kahal Cross).

[14] Hearing Tr. Vol. XXIV, p. 4906 (Kahal Cross).

[15] *Id.*

Indeed, consistent with Mr. Kahal's admissions, the Commission "[has] repeatedly held that [it] will not require any single party, including OCC/NOAC, to agree to a stipulation in order to meet the first prong of the three-prong test."[16] Additionally, the Commission approved the Companies' ESP III stipulation over the objections of OCC/NOAC and NOPEC who claimed, as they do here, that the stipulation failed to represent adequately the interests of residential customers.[17] The Commission held that "the signatory parties represent diverse interests including the Companies, a municipality, competitive suppliers, commercial customers, industrial consumers, advocates for low and moderate-income customers, and Staff."[18] In rejecting the argument that residential customers were not adequately represented, the Commission has also expressly found that OPAE and the Citizens Coalition advocate on behalf of low and moderate-income residential customers.[19] Thus, OCC/NOAC find no support for their position in Commission precedent or on this record.

Relying on OMAEG witness Hill's testimony, OMAEG argues that the serious bargaining prong is not satisfied because the Signatory Parties "only represent themselves" and provide a "facade of representational diversity."[20] Dr. Hill's opinions with respect to the interests of the Signatory Parties or the diverse interests they represent were, however, revealed at hearing as uninformed conjecture. Dr. Hill admitted, for example, that he reviewed no

[16] *In the Matter of the Application of Vectren Energy Delivery of Ohio, Inc., for Approval of an Alternative Rate Plan for Continuation of its Distribution Replacement Rider,* Case No. 13-1571-GA-ALT, 2014 Ohio PUC LEXIS 33, at *21-22, Opinion and Order (Feb. 19, 2014).

[17] *In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan,* Case No. 12-1230-EL-SSO, 2012 Ohio PUC LEXIS 706 at *51-53, Opinion and Order (July 18, 2012).

[18] *Id.* at *55.

[19] *Id.*

[20] OMAEG Brief, p. 74.

discovery prior to drafting his Direct Testimony.[21] Nor did he bother to review the stipulations entered into in any previous ESP proceedings.[22] Dr. Hill also never had any discussions with any Signatory Party concerning their intent in signing the stipulations filed before the Third Supplemental Stipulation.[23] He further admitted he had no knowledge of the content of settlement discussions which occurred prior to the Third Supplemental Stipulation and that he was not present at any settlement meetings relating to any of the stipulations in this proceeding.[24] With respect to Staff, Dr. Hill stated that he believes that Staff does not represent the interest of the general public.[25] Instead, Dr. Hill brazenly believes that Staff represent their "own preferences and career self-interest."[26] Dr. Hill's testimony is therefore uninformed by any knowledge of either the settlement discussions that actually took place or even a basic understanding of the diverse interests represented by the Signatory Parties. OMAEG's contentions, relying as they do on Dr. Hill's testimony, can be easily rejected.

B. There Was Serious Bargaining Here.

Given the lengthy process that ultimately led to the Stipulated ESP IV and given the diversity of interests represented by the Signatory Parties, the intervenors opposing the Stipulations here are left with no established or accepted argument by which to justify an attack on the first prong of the Stipulation approval test. It is not surprising that they make up a new one. Apparently conceding that there was bargaining, they attempt to denigrate the negotiations,

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[21] Hearing Tr. Vol. XXVII, p. 5493 (Hill Cross).

[22] Hearing Tr. Vol. XXVII, p. 5495 (Hill Cross).

[23] Hearing Tr. Vol. XXVII, pp. 5507-08 (Hill Cross).

[24] Hearing Tr. Vol. XXXIX, pp. 8380-81 (Hill Cross).

[25] Hearing Tr. Vol. XXXIX, p. 8344 (Hill Cross).

[26] Hearing Tr. Vol. XXXIX, p. 8344 (Hill Cross).

using the term "favor trading."[27] Their theory, apparently, is if any Signatory Party was able to negotiate a benefit, that disqualifies them from being engaged in "serious bargaining." RESA, for example, characterizes the funds committed by the Companies to energy efficiency projects, energy efficiency advancement/education initiatives and fuel funds as "inducements" that illustrate that serious bargaining did not occur.[28] OMAEG echoes RESA's arguments by complaining that the Signatory Parties were only looking out for their individual interests.[29]

Such arguments do more than just ignore the fundamental nature of the bargaining process; they suggest that the inherent "give-and-take" of multi-party negotiations is illegitimate. These arguments ask the Commission to impose a standard on stipulations that would be impossible to meet. If parties cannot agree to give something up to get something in return, no party could ever engage in "serious bargaining" and there would never be any stipulations approved by the Commission.

In a similar vein, OCC/NOAC baldly assert that payments of "cash and cash equivalents" to signatory parties are "strongly disfavored" by the Commission.[30] To support this proposition, these parties cite *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Ultimate Construction and Operation of an Integrated Gasification Combined Cycle Electric Generation Facility* ("*AEP Ohio Construction Case*"), Case No. 05-376-EL-UNC, Order on Remand (Feb. 11, 2015). That case hardly stands for the broad proposition asserted by OCC/NOAC. In that matter, the signatory parties stipulated to a process to refund funds due to customers.[31] Part of that process

[27] *See* Exelon Brief, pp. 65-66; EPSA/P3 Brief, pp. 40-41; RESA Brief, p. 41; OCC/NOAC Brief, p. 35.

[28] RESA Brief, p. 41.

[29] OMAEG Brief, p. 71; Hill Third Supp., pp. 7-8.

[30] OCC/NOAC Brief, pp. 28-29.

[31] *AEP Ohio Construction Case*, pp. 7-8.

included a structure by which AEP Ohio, for the sake of reducing "administrative complexity," paid large sums directly to certain of the signatory parties consisting of groups of customers, and those signatory parties, in turn, agreed to distribute the entirety of the funds received to their members.[32] It was *this* structure – which directed to *intervenors* of "funds to be refunded to *ratepayers*" – with which the Commission took issue, not the mere fact that signatory parties received a certain amount of funds.[33] Here, there is no such process. Unlike in the *AEP Ohio Construction Case*, in Stipulated ESP IV, there are no funds due customers that are being paid to Signatory Parties. Here, monies to be paid by the Companies will be for services to assist the Companies in achieving energy efficiency and peak demand reduction mandates or for assistance to be provided to customers.

RESA, OMAEG and OCC/NOAC seek to have the Commission interpret "serious bargaining" away and effectively preclude the approval of any stipulation. Their interpretations should be rejected. As the Third Supplemental Stipulation makes clear, the Signatory Parties here recognized that it is through the give and take of negotiations with multiple parties having their own interests to advance that a compromise is reached worthy of consideration by the Commission:

> The Stipulated ESP IV is the product of the discussions and negotiations of the Signatory Parties, and is not intended to reflect the views or proposals which any individual party may have advanced acting unilaterally. Accordingly, the Stipulated ESP IV represents an accommodation of the diverse interests represented by the Signatory Parties, and is entitled to careful consideration by the Commission.[34]

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[32] *Id.*

[33] *Id.*, pp. 11-12 (emphasis added).

[34] Third Supp. Stip., p. 5.

Further, these intervenors' unrealistic expectation of apparently selfless negotiations cannot change the fact that the Signatory Parties are capable negotiators in ESP proceedings.[35] These intervenors also cannot change the fact that, given the record in this case, the Signatory Parties have an extensive knowledge of the strengths and weaknesses of various parties' positions.[36] They similarly cannot change the fact that the Stipulated ESP IV is a significant departure from the Companies' initial application as a result of the serious bargaining that took place over the span of more than a year and a half.[37] The Commission has ample facts before it proving that the Stipulated ESP IV is the product of serious bargaining by capable, knowledgeable parties.

C. The Competitive Market Enhancement Agreement Does Nothing To Undermine the Serious Bargaining Process.

Certain intervenors rely on a flawed interpretation of Ohio law and Commission precedent to argue that an agreement between the Companies and Signatory Party Interstate Gas Supply, Inc. ("IGS") indicates that serious bargaining did not take place.[38] As RESA notes, on January 14, 2016, the Companies notified the parties that IGS had agreed to sign the Third Supplemental Stipulation and that a separate agreement, titled the "Competitive Market Enhancement Agreement" (the "Enhancement Agreement"), had been agreed upon between the Companies and IGS.[39] The Enhancement Agreement was provided to the parties on January 14, 2016.[40] IGS's signature to the Third Supplemental Stipulation was officially docketed the

[35] Mikkelsen Fifth Supp., p. 8.

[36] Mikkelsen Fifth Supp., p. 8; Mikkelsen Supp., pp. 5, 7; Hearing Tr. Vol. I, pp. 214-16 (Mikkelsen Cross).

[37] Hearing Tr. Vol. I, pp. 214-16 (Mikkelsen Cross). *See generally* Stipulation, Supp. Stipulation, Second Supp. Stip., Third Supp. Stip.

[38] Exelon Brief, pp. 63-65; OCC/NOAC Brief, pp. 42-45; OMAEG Brief, pp. 75-76; RESA Brief, pp. 42-44 .

[39] RESA Brief, p. 42.

[40] RESA Brief, p. 42; OMAEG Ex. 24 (the Enhancement Agreement)

following day.[41] At hearing on January 15, 2016, Company witness Mikkelsen was offered for cross-examination on issues relating to the Enhancement Agreement and to the process of IGS' decision to sign the Third Supplemental Stipulation.[42] The Attorney Examiner also provided parties, including Exelon and RESA, that had concluded cross-examination of Ms. Mikkelsen the previous day with another opportunity to question her concerning any issues related to the Enhancement Agreement.[43] Counsel for Exelon and RESA took that opportunity to ask Ms. Mikkelsen a single question.[44] OMAEG and OCC/NOAC engaged in a more thorough cross-examination of Ms. Mikkelsen.[45] No Signatory Parties cross-examined Ms. Mikkelsen, and none has raised concerns in its brief relating to the Enhancement Agreement.

Exelon, OMAEG and RESA argue that the side agreement with IGS precludes a finding that the Signatory Parties engaged in serious bargaining because the agreement was not disclosed until January 14, 2016.[46] These parties never bother to explain why this is so. To be sure, they cite the Ohio Supreme Court's decision in *Ohio Consumers' Counsel v. Public Utilities Commission.*[47] In that case, the Court remanded a Commission order that had not permitted the discovery of undisclosed side agreements.[48] The Court held that the non-disclosure of side

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[41] OMAEG Ex. 25 (IGS' as-filed signature to the Third Supplemental Stipulation).

[42] Hearing Tr. Vol. XXXVII, pp. 7806-7826, 7904-7910, 7917, 7920-7937 (Mikkelsen Cross).

[43] Hearing Tr. Vol. XXXVII, p. 7916 (Mikkelsen Cross).

[44] Hearing Tr. Vol. XXXVII, p. 7917 (Mikkelsen Cross).

[45] *See* Hearing Tr. Vol. XXXVII, pp. 7804-7826 (Mikkelsen Cross) (OMAEG cross on the Enhancement Agreement); Hearing Tr. Vol. XXXVII, pp. 7920-7960 (Mikkelsen Cross) (OCC cross on the Enhancement Agreement).

[46] Exelon Brief, pp. 63-65; OMAEG Brief, pp. 75-76; RESA Brief, pp. 42-44. Each of these parties relies on *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 111 Ohio St.3d 300, 2006-Ohio-5789, to establish that the existence of side agreements may be relevant to the serious bargaining prong.

[47] Exelon Brief, p. 63; OMAEG Brief, p. 76; RESA Brief, p. 42.

[48] 111 Ohio St.3d at 323.

agreements could implicate the serious bargaining prong.[49] Notably, the Court was addressing the issue of the discoverability of side agreements. The Court held side agreements *discoverable* because they are relevant to the serious bargaining prong. The Court never said that side agreements negate or disprove serious bargaining. Rather, the Court took the common sense view that, for the Commission to understand what bargaining took place, it had to be able to review *all* of the bargaining that took place.[50]

RESA contends that upon remand from the Court in *Ohio Consumers' Counsel*, the Commission found that the serious bargaining prong had not been satisfied.[51] But the Commission's decision in the remand proceeding was based on the fact that the *existence* of the *undisclosed* side agreements, in which several signatory parties had privately agreed to support the stipulation, "raise[d] serious doubts about the integrity and openness of the negotiation process[.]"[52]

Here, the Commission and the parties have had the opportunity to understand all of the bargaining. The Enhancement Agreement was disclosed almost immediately upon execution, as the intervenors concede.[53] Further, all parties were provided with an opportunity to review the agreement and then to cross-examine Company witness Mikkelsen. The fact that counsel for

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[49] *Id.* at 319, 320.

[50] *Id.* at 321; *See also In the Matter of the Application of The Cincinnati Gas & Electric Company to Modify its Nonresidential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish an Alternative Competitive-Bid Service Rate Option Subsequent to the Market Development Period*, Nos. 03-93-EL-ATA, 03-2079-EL-AAM, 03-2081-EL-AAM, 03-2080-EL-ATA, 2007 Ohio PUC LEXIS 703, at *46, Order on Remand (October 24, 2007) (the "CG & E Remand Proceeding") (holding that side agreements are discoverable and should be considered in evaluating the integrity and openness of the bargaining process).

[51] RESA Brief, p. 43 and n. 129 (discussing the CG & E Remand Proceeding).

[52] CG & E Remand Proceeding, Order on Remand p. 62.

[53] *See* OMAEG Ex. 24 (demonstrating that the Enhancement Agreement was signed on January 14, 2016); RESA Brief, p. 42 (admitting that the Enhancement Agreement was provided to the parties on January 14, 2016).

Exelon and RESA took that opportunity to ask a single question of Ms. Mikkelsen leaves their claim that the agreement was the product of "secretive execution" unpersuasive at best.[54]

It is well settled that the Commission has an abiding interest in the resolution of disputes through stipulations that avoid the expense of litigation.[55] Parties to Commission proceedings should always be working to amicably resolve their disputes. The Enhancement Agreement does not demonstrate that serious bargaining did not occur. Indeed, the Enhancement Agreement demonstrates just the opposite – that the Companies continued to bargain with opposing parties for the entirety of this lengthy proceeding.

Notably, any claims by Exelon, RESA and OMAEG about any possible delay in disclosing the Enhancement Agreement are misplaced. Assuming arguendo that the Companies had any unfair advantage in bargaining (which is not the case), the parties that should be heard from would be the other Signatory Parties. But there is no evidence of any unfair advantage, and no Signatory Party has raised an objection to the agreement. Accordingly, the Enhancement Agreement does nothing to call into question the robust bargaining process that occurred in this matter.[56]

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[54] Exelon Brief, p. 64; RESA Brief, p. 43.

[55] *See, e.g., In the Matter of the Determination of the Existence of Significantly Excessive Earnings for 2010 Under the Elec. Sec. Plan of Ohio Edison Co., the Cleveland Elec. Illuminating Co., & the Toledo Edison Co.*, 11-4553-EL-UNC, 2012 WL 252212 (Jan. 18, 2012) ("[T]he Stipulation is in the public interest because it avoids further litigation in this matter."); *In Re Ne. Ohio Nat. Gas Corp.*, 06-209-GA-GCR, 2006 WL 2433256, at *5 (Aug. 23, 2006) ("By avoiding the cost of litigation, we conclude that the stipulation will benefit ratepayers and is in the public interest."); *In Re Cincinnati Gas & Elec. Co.*, 02-218-GA-GCR, 2003 WL 22473331 (Oct. 15, 2003) (same); *In Re Dayton Power & Light Co.*, 91-414-EL-AIR, 1992 WL 281169 (Jan. 22, 1992) ("[A]ll parties are benefited in that extensive litigation has been avoided. Absent the stipulation and recommendation, the costs of a fully-litigated case would ultimately be passed on to ratepayers through higher rates or reflected in their tax payment to support the experts protecting their interests.").

[56] Despite the *Ohio Consumers' Counsel* Court's explicit holding that side agreements are relevant solely to the serious bargaining prong, OCC/NOAC argue the merits of the Enhancement Agreement. OCC/NOAC Brief, pp. 42-45. But the Enhancement Agreement is simply not before the Commission at this time. Hearing Tr. Vol. XXXVII, p. 7823 (Mikkelsen Cross) (discussing the future filing of the Enhancement Agreement before the Commission). When the various proposals in the agreement come before the Commission, OCC/NOAC will be free to intervene and assert their arguments. Ms. Mikkelsen's testimony was unequivocal on this point: "The [Enhancement Agreement] is independent of any of the agreements that have been made in Case 14-1297-EL-SSO,

D. Serious Bargaining In An ESP Can Occur And It Occurred Here.

Relying on a concurring opinion by a former Commissioner, some intervenors argue that there can be no serious bargaining in an ESP proceeding because, under the ESP statute, an electric distribution utility ("EDU") may reject modifications to a proposed ESP.[57] At the risk of stating the obvious, if this were true, the Commission could not have approved any stipulations in any ESP proceeding. Of course, the Commission has, in fact, found serious bargaining occurred as part of its approval of numerous ESPs, including those involving the Companies, AEP Ohio, Duke Energy Ohio or DP&L.[58] Even more curiously, if it was true that an EDU's right to withdraw an ESP precluded serious bargaining, then OCC/NOAC and NOPEC could not have entered into stipulations in prior ESP proceedings and advocated to this Commission that those stipulations were the product of serious bargaining.[59] Further, even OCC/NOAC/NOPEC's witness could not agree to the proposition that serious bargaining could not occur in an ESP. Although OCC/NOPEC witness Kahal argued in pre-filed testimony that

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and the filings pursuant to the [Enhancement Agreement] will be made outside of Case 14-1297-El-SSO." Hearing Tr. Vol. XXXVII, p. 7824 (Mikkelsen Cross). Because OCC/NOAC's arguments are in no way relevant to this proceeding, they should be disregarded.

[57] OCC/NOAC Brief, pp. 26-28; OMAEG Brief, pp. 77; NOPEC Brief, pp. 70-71. Each of these parties relies upon statements made by former Commissioner Cheryl Roberto in a concurring opinion in *In re FirstEnergy's 2008 ESP Case*, Case No. 08-935-EL-SSO, Second Finding and Order, Opinion of Commissioner Cheryl L. Roberto Concurring in Part and Dissenting in Part, pp. 1-2 (Mar. 25, 2009).

[58] *See, e.g.*, Case No. 12-1230-EL-SSO, Opinion and Order, p. 26 (July 18, 2012) (finding serious bargaining in support of the stipulation in the Companies' ESP III proceeding); Case No. 10-388-EL-SSO, Opinion and Order, p. 24 (Aug. 25, 2010) (finding serious bargaining in support of the stipulation in the Companies' ESP II proceeding); Case No. 11-346-EL-SSO, Opinion and Order, p. 35 (Dec. 14, 2011) (finding that the stipulation in AEP's ESP II was the product of serious bargaining); Case No. 11-3549-EL-SSO, Opinion and Order, p. 42 (Nov. 22, 2011) (finding serious bargaining in support of the stipulation in Duke's ESP proceeding); Case No. 08-1094-EL-SSO, Opinion and Order, p. 7 (June 24, 2009) (finding that the stipulation in DP&L's ESP proceeding was the product of serious bargaining.

[59] *See* Case No. 08-935-EL-SSO, Second Opinion and Order, pp. 7, 17 (Mar. 25, 2009) (OCC and NOPEC as signatories to supplemental stipulation); Case No. 08-920-EL-SSO, Opinion and Order, pp. 6, 28 (Dec. 17, 2008) (OCC as signatory to stipulation); Case No. 11-3549-EL-SSO, Opinion and Order, pp. 4-5, 42 (Nov. 22, 2011) (OCC as signatory to stipulation); Case No. 08-1094-EL-SSO, Opinion and Order, pp. 4, 7 (June 24, 2009) (OCC as signatory to stipulation).

serious bargaining could not be achieved in an ESP proceeding,[60] he conceded at hearing that he, in fact, is not ruling out stipulations in ESP proceedings.[61] Indeed, contrary to his pre-filed testimony, he agreed that a stipulation filed in an ESP proceeding can satisfy the serious bargaining prong of the Commission's three-part test.[62]

III. STIPULATED ESP IV BENEFITS CUSTOMERS AND IS IN THE PUBLIC INTEREST

In the Companies' Initial Brief, the Companies showed the many ways in which Stipulated ESP IV will benefit customers and be in the public interest.[63] At a high-level, Stipulated ESP IV will ensure customer access to market-based retail rates while giving customers retail rate stability that functions like insurance or a hedge against future market risks. It also helps to ensure reasonably priced and reliable distribution service, supports economic development through multiple initiatives, encourages energy efficiency and peak demand reduction, protects at-risk populations, helps large industrial customers better compete in the global marketplace, provides competitive market enhancements, and promotes grid modernization and resource diversification.[64] The Companies' proposed retail rate stability mechanism – Rider RRS – also satisfies the four non-binding criteria established by the Commission in its *AEP ESP3* Order for PPA-type riders.[65] Thus, Stipulated ESP IV satisfies the second prong of the Commission's three-part test.

Opponents of Stipulated ESP IV focus their efforts on Rider RRS, the Companies' retail rate stability mechanism when addressing the second prong of the Commission's three-part test.

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[60] Kahal Second Supp., pp. 6-7.

[61] Hearing Tr. Vol. XXXVIII, p. 8213 (Kahal Cross).

[62] Hearing Tr. Vol. XXXVIII, p. 8213 (Kahal Cross).

[63] Companies' Initial Brief, pp. 40-112.

[64] *Id. See* Mikkelsen Fifth Supp., p. 10.

[65] AEP ESP3 Order, p. 25.

As discussed in Sections III.A.1. and III.A.2. below, having produced no reliable forecasts of their own, they question the forecasts prepared by Company witnesses Rose and Lisowski and attempt to raise doubts regarding the effectiveness of Rider RRS to provide retail rate stability. They also mischaracterize Rider RRS as an anti-competitive subsidy that could harm wholesale or retail power markets, which is rebutted in Section III.A.3. below. They also question whether Rider RRS will promote reliability, which is rebutted in Section III.A.4. below.

Lastly, with regard to Rider RRS, opponents question whether Rider RRS is supported by a balancing of the *AEP ESP3* criteria, and go so far as to suggest additional criteria. As discussed in the Companies' Initial Brief, the Plants have a significant financial need, are needed given future reliability concerns, and are compliant with all existing and pending environmental regulations.[66] Moreover, their closing would have a significant negative impact on electric prices and retail rate stability, with a resulting negative impact on economic development.[67] The Companies rebut opponents' arguments regarding the *AEP ESP3* criteria in Section III.A.5. below.

The benefits of Stipulated ESP IV do not end, of course, with Rider RRS, and intervenors do make scatter-shot attempts to challenge its other riders and provisions. In Sections III.B. through III.E., the Companies respond to opponents' criticisms and/or recommendations regarding Riders DCR, NMB and ELR and competitive market enhancements. Criticisms of the new Rider NMB Opt-Out Pilot Program are addressed in Section III.F., below. Unneeded amendments to the Master Supply Agreement are discussed in Section III.G., below. And criticisms of the resource diversification and grid modernization provisions included in the Third Supplemental Stipulation are controverted in Sections III.H. and III.I., below.

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[66] Companies' Initial Brief, pp. 124-40.

[67] Companies' Initial Brief, pp. 140-44.

The discussion of these topics is lengthy, but that is the inevitable result of the Companies' and the Signatory Parties' efforts to recommend to the Commission an ESP that broadly employs the stability, security and economic development provisions authorized for inclusion in an ESP by the General Assembly.

A. Rider RRS Will Provide Rate Stability, Reliability, and Economic Benefits to Customers.

Rider RRS is intended to address the risks customers will face over the next eight years. They face market risks from increasing and more volatile retail electric prices. And they face risks from the "rush to gas" that could destabilize energy prices while threatening the Companies' ability to provide reliable distribution service. Intervenors opposed to Rider RRS largely ignore these risks. Instead, they filed testimony and briefs that are the equivalent of waving one's arms wildly in the air to distract the Commission from the relevant concerns addressed by the Companies' Stipulated ESP IV. What all that arm waiving cannot do is magically make the record disappear. It is the voluminous record here – the facts on which the Commission must decide this case – that supports the Commission's approval of Rider RRS.

1. The Companies' forecasts are reliable.

The Companies have demonstrated that Rider RRS benefits customers through the use of the most thorough and reliable forecast models available. Some of the opponents to Stipulated ESP IV attempt to attack the various steps in the Company's forecast evidence. They attack Mr. Rose's forecasts; they attack Mr. Lisowski's forecasts. But as shown below, Mr. Rose's work is the only forecast in this case. It is based on a reliable, widely accepted methodology. Attempts at criticizing Mr. Rose fail because, at every turn, the unrebutted evidence refutes the criticisms. Attempts to offer contrary "numbers" fail because such evidence comes largely from witnesses with no forecasting expertise who admit that they did no forecasts. None of the "numbers" provided by other witnesses are based on anything other than ad hoc, result-oriented methods.

The intervenors also attack Mr. Lisowski's cost and revenue estimates. Some intervenors criticize Mr. Lisowski's model, but no intervenor used any of the commercially available models to contest Mr. Lisowski's results or identified any flaw in Mr. Lisowski's modeling. Mr. Lisowski's model appropriately addresses all costs (including both known and projected environmental costs) and revenues for the Plants. In addition, recent events have shown that Mr. Lisowski's analysis was actually conservative, as the Capacity Performance ("CP")requirements have increased projected revenues.

a. **The Companies offered the only valid market price forecast in this case.**

The parties opposing the Stipulated ESP would have the Commission believe that given the number of projections regarding the net credits or charges to be provided by Rider RRS, one of two conclusions must prevail: (1) no one can possibly know whether Rider RRS will provide a net credit; or (2) the Companies' projection of substantial credits must be rejected. For its part, OCC/NOAC complains that the Companies refuse to guarantee the results of their forecast[68] and that the impact of Rider RRS cannot be known with any certainty.[69] Sierra Club and Exelon argue that the Companies are the only parties that believe Rider RRS will result in a net credit over the eight-year term.[70] These parties are wrong for a variety of reasons.

First, to be sure, forecasts are forecasts and therefore are not – and can never be – a guarantee of future results. But, as noted, matters before the Commission frequently involve dealing with future events and this is always the case for an ESP. Thus, the task before the

[68] OCC/NOAC Brief, p. 76.

[69] OCC/NOAC Brief, p. 76.

[70] Exelon Brief, p. 32; Sierra Club Brief, p. 14.

Commission in this case is to choose the best and most reliable tools to assess the likelihood and consequences of future events.

Second, the Companies' forecast evidence is qualitatively superior to what was sponsored by other parties. But it was not merely the result that distinguished this evidence; it was the fact that only the Companies provided a witness who did a bona fide forecast using a widely accepted and reliable methodology.

Third, the record evidence shows that the other widely accepted forecasts, such as the 2014 and 2015 Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") Reference Cases,[71] produced very similar results to Company witness Rose's forecasts. Thus, when the record is properly evaluated, the Commission must look to reliable forecasts based on an accepted methodology and reject evidence that represents hackneyed, result-oriented and untried "projections" pretending to be forecasts.

To begin, Company witness Rose was the only witness in this proceeding who generated numerous independent forecasts through the use of sophisticated computer modeling. Indeed, Mr. Rose not only provided forecasts for wholesale electricity prices (electrical energy and capacity prices), but he also provided forecasts of prices for inputs into the production of electricity, *e.g.*, coal, natural gas, CO_2 emission allowances, and costs of new power plants.[72]

As Mr. Rose explained, proper modeling must incorporate several important features. First, the model must be widely used and recognized.[73] Second, the model explicitly should treat key supply and demand parameters.[74] Third, the model also needs to conform to generally

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[71] *See* Section III.A.2, *infra.*

[72] Rose Rebuttal, p. 3. (In what follows, Company witness Judah Rose will be referred to as "Rose" and OCC witness Kenneth Rose will be referred to as "K. Rose.")

[73] Rose Rebuttal, p. 3.

[74] Rose Rebuttal, p. 3.

accepted price forecasting principles.[75] For example, in the case of a long-term forecast of natural gas, futures and current spot prices should not be used beyond the first two years.[76] This is due to the extreme volatility of futures and spot gas prices and because longer-term futures prices primarily reflect merely bids and not completed transactions.[77] Fourth, there needs to be a detailed consideration of key components. For instance, the model needs to account for environmental regulations that may impact the production of power or the location and level of demand.[78] Fifth, the model must treat properly the relationships between the key variables involved, *e.g.*, if supply decreases then prices should increase, which in turn should increase supply.[79] Sixth, any appropriate model in the power industry must properly address fuel-related industries.[80]

To generate his forecasts, Mr. Rose employed highly sophisticated computer models that met these criteria, including such widely recognized models as ICF's Integrated Planning Model ("IPM"), General Electric's GE-MAPS, and ICF's Gas Market Model ("GMM").[81] Mr. Rose described the function of the GE-MAPS model:

> GE-MAPS is a widely accepted and highly detailed model based on supply and demand fundamentals. GE-MAPS chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. GE-MAPS uses a detailed electrical model of the entire transmission network, along with generation shift factors

[75] Rose Rebuttal, p. 3.

[76] Rose Rebuttal, p. 3.

[77] Rose Rebuttal, p. 3.

[78] Rose Rebuttal, p. 3.

[79] Rose Rebuttal, p. 3.

[80] Rose Rebuttal, p. 3.

[81] Rose Rebuttal, p. 3.

> determined from a solved alternating current (AC) load flow, to calculate the real power flows for each generation dispatch.[82]

Mr. Rose also described the function of IPM and how IPM differs from GE-MAPS:

> IPM is a widely used and accepted forecasting model based on supply and demand fundamentals that forecasts hourly electrical energy prices. IPM is also a dynamic model that optimizes capacity decisions over the entire planning period simultaneously. Over time, this becomes more important in the energy market, and is especially critical for forecasting capacity prices. GE-MAPS does not incorporate investment decision making endogenously because of its very detailed treatment of transmission and nodal pricing.[83]

These sophisticated models enabled Mr. Rose to engage in detailed computer modeling of the relevant power markets (*i.e.*, ATSI Zone and AEP Dayton, and selected nodal markets for electrical energy and the PJM RTO capacity price), and associated fuel industries.[84] EPSA/P3 witness Kalt admitted that ICF uses a sophisticated computer model, IPM, involving a number of interdependent variables to generate its forecasts.[85]

Notably, as Mr. Rose explained:

> The models have extensive treatments of supply and demand and capture the level of detail required, including production, transportation and consumption. The relationships among the key variables are modeled – *e.g.*, there is an integrated treatment of pricing, quantities, etc. I also have detailed treatments of the key fuel industries including natural gas via GMM and coal via IPM. I also do not violate key principles related to long-term energy price forecasting in the power and gas sectors such as inappropriate reliance on current conditions in highly volatile industries such as natural gas.[86]

These models addressed uncertainty head-on. Indeed, as Mr. Rose explained,

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[82] Rose Direct, pp. 44-45.

[83] Rose Rebuttal, p. 45.

[84] Rose Rebuttal, p. 3.

[85] Hearing Tr. Vol. XLI, pp. 8640-42 (Kalt Cross).

[86] Rose Rebuttal, p. 7.

> My treatment is the same as the treatment in ICF's Regulatory Impact Analysis ("RIA") of the Clean Power Plan conducted for the U.S. EPA using its assumptions. I provided a probability-weighted projection also referred to as an 'Expected Value' forecast, which is the key basis for decision making.[87]

For example, in his wholesale power price forecast, Mr. Rose provided a base case projection that reflected the probability-weighted or expected value forecast of wholesale power prices.[88] "Probability weighting incorporates uncertainty and the relative likelihood of a range of outcomes."[89] This is crucial because:

> The Base Case projection should reflect the probability weighted (also referred to in mathematical parlance as the expected outcome) forecast of wholesale power prices. This allows decision makers to minimize expected costs using a risk-adjusted discount rate to discount the expected case - *e.g.*, to calculate the discounted present value of expected future long-term prices with and without hedges. This is the proper approach to decision making for entities seeking to minimize expected cost. Thus, the most important wholesale price projection is the probability weighted case (*i.e.*, the expected case).[90]

In contrast, as discussed later,[91] OCC/NOPEC witness Wilson, Sierra Club witness Comings, and EPSA/P3 witness Kalt did none of these things. Each of these witnesses admitted that they did not rely on computer models of any sort.[92] Indeed, Mr. Wilson went so far as to

[87] Rose Rebuttal, p. 10.

[88] Rose Rebuttal, p. 10.

[89] Rose Rebuttal, p. 10

[90] Rose Rebuttal, p. 10.

[91] *See* Section III.A.2, *infra*.

[92] Hearing Tr. Vol. XXII, p. 4542 (Wilson Cross); Hearing Tr. Vol. XXXI, p. 6414 (Comings Cross); Hearing Tr. Vol. XLI, p. 8642 (Kalt Cross). Mr. Comings admitted that the only analysis he performed consisted of "adjusting the [C]ompanies' forecasts for different variables." Hearing Tr. Vol. XXXI, p. 6414 (Comings Cross).

admit that he does not "do" forecasts.[93] All three problematically relied on illiquid futures in their long-term analyses.[94]

Ironically, the only "calculations" that Mr. Wilson did involving the EIA AEO Reference Cases essentially show Rider RRS to produce a credit. In his Direct Testimony, Mr. Wilson estimates that under his Reference Case "analysis" customers would receive a $200 million credit (over a fifteen-year term),[95] while in his Second Supplemental Testimony Mr. Wilson declares that under a similar Reference Case analysis customers would "roughly break even" with a $50 million credit (over an eight-year term).[96] Even more ironically, the AEO Reference Cases are the only "methodologically sound" parts of Mr. Wilson's analysis.[97] As Mr. Rose explained, the Reference Cases appear to be the most appropriate cases for Mr. Wilson to use given that they appear to be "the closest to a probability weighted expected case."[98] Notably, as Mr. Rose opined, "a key virtue" of the Reference Case is "that it reflects methodologically sound modeling of supply and demand."[99] In the 2014 AEO Preface, the EIA specifically emphasizes its use of sophisticated computer modeling to generate the Reference Case:

> The Annual Energy Outlook 2014 (AEO2014), prepared by the U.S. Energy Information Administration (EIA), presents long term annual projections of energy supply, demand, and prices focused on the U.S. through 2040, based on results from EIA's National Energy Modeling System (NEMS). NEMS enables EIA to make

[93] Hearing Tr. Vol. XXXVIII, p. 8116 (Wilson Cross).

[94] Hearing Tr. Vol. XXII, p. 4567 (Wilson Cross); Hearing Tr. Vol. XXXI p. 6476 (Comings Cross); Hearing Tr. Vol. XLI, pp. 8680-81 (Kalt Cross).

[95] Wilson Direct, p. 12.

[96] Wilson Second Supp., pp. 6, 7, 12.

[97] Rose Rebuttal, p. 42. Mr. Wilson otherwise relies on the 2014/2015 High Oil and Gas Resources Cases and natural gas futures. *See*, *e.g.*, Wilson Second Supp., p. 11-12. As explained below, Mr. Wilson's choice of the High Oil and Gas Resource Case displays complete bias and his reliance on natural gas futures cannot form the basis for any sort of meaningful long-term projection.

[98] Rose Rebuttal, p. 42.

[99] Rose Rebuttal, p. 42.

> projections under alternative, internally-consistent sets of assumptions, the results of which are presented as cases [one of which is the] Reference Case.[100]

And further: "EIA has endeavored to make these projections as objective, reliable, and useful as possible."[101] The Reference Case is specifically described as follows: "The AEO 2014 Reference Case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends."[102]

Notably, the only two methodologically sound, widely recognized models in the record here produced similar results:

> The EIA AEO 2014 projection [for natural gas prices] in real dollars [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] than ICF's projection over the same period. . . . As noted, the 2015 EIA AEO reference price forecast on average is similar to the 2014 forecast and [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] than the ICF projection.[103]

As Sierra Club witness Comings admitted at hearing, [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[104]

It is undisputed that the Companies are the only party to this matter that generated independent forecasts based upon probability-weighted cases. As demonstrated below, none of the criticisms of Mr. Rose can withstand critical scrutiny. Indeed, they represent a misunderstanding, or willful ignorance, of forecasting and Mr. Rose's methodology.

[100] Company Ex. 60 (2014 EIA AEO) at ii.

[101] Company Ex. 60 (2014 EIA AEO) at iii.

[102] Company Ex. 60 (2014 EIA AEO) at iii.

[103] Rose Rebuttal, pp. 41-42 (emphasis added).

[104] Hearing Tr. Vol. XXXI (Confidential), p. 6494 (Comings Cross).

As also discussed further below, the only other worthwhile forecasts here (*i.e.*, the 2014 and 2015 EIA AEO Reference Cases) were apparently summarily rejected by Mr. Wilson because they did not provide him with his desired result, *i.e.*, that Rider RRS be a charge to customers. Further, no party has come forward with a better way to address future uncertainty – precisely because there is none. Indeed, the putative claims that the Companies' forecasts are outliers or that there is no "agreement" as to the effect of Rider RRS trade on a false equivalence between Mr. Rose's *bona fide* forecasts on the one hand, and, the biased and methodologically unmoored "calculations" of intervenors' witnesses on the other. As such, these criticisms are meritless.

b. **Mr. Rose's energy price forecasts are reasonable and reliable despite opposing intervenors' myopic focus on short-term natural gas prices.**

Company witness Rose was the only witness to produce an energy price forecast that is based on a fundamental analysis of market indicators, including but not limited to, higher natural gas prices over time.[105] Those opposing Stipulated ESP IV argue, overly simplistically, that Mr. Rose's natural gas price forecasts are the basis of his energy price forecasts, that Mr. Rose's natural gas forecasts are wrong, and that both should be rejected. As demonstrated below, these criticisms are mistaken and irrelevant. Short-term changes in natural gas prices, even dramatic ones, are not unexpected because natural gas prices are highly volatile. However, long-term trends, as demonstrated by market fundamentals, demonstrate the likelihood of Mr. Rose's long-term energy price forecasts.[106] In any event, given the short-term reliance of the energy market on coal prices to set energy prices, short-term changes in natural gas prices have a muted effect on likely long-term natural gas price trends.

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[105] Rose Direct, pp. 5-6, 19-20. *See* Companies' Initial Brief, p. 14.

[106] Rose Rebuttal, pp, 31-42.

Certain opponents of Stipulated ESP IV also argue that Mr. Rose's natural gas price forecasts are unreliable because the Companies failed to do any "sensitivity analysis." These arguments also go begging under the weight of the evidence which shows that such analyses were not only unfeasible but also unnecessary because Mr. Rose's forecasts are probability weighted and thus already factor in uncertainty and the expected range of likely outcomes.

(i) Mr. Rose's forecasts are not stale.

ELPC, Sierra Club and Cleveland argue that recent developments in natural gas prices undermine Mr. Rose's natural gas forecasts. As ELPC contends, "[S]ince Company witness Rose prepared his market price forecast in the summer of 2014, natural gas prices – a significant driver of energy prices – have dropped dramatically."[107] Likewise, Sierra Club claims that Mr. Rose's "natural gas price forecast is unreasonably high and lacking in credibility."[108] Similarly, Cleveland argues that Mr. Rose is relying on natural gas assumptions that are "out of date" – relying on EPSA/P3 witness Kalt for support.[109]

Intervenors' arguments lose sight of the forest for the trees. Their arguments are meritless for three reasons. First, intervenors ignore the extremely volatile nature of natural gas prices. Second, intervenors ignore the fundamentals of the current natural gas market which support a long-term trend of price increases. Third, even if there were any questions about the specific accuracy of Mr. Rose's gas forecast in the short term, such concerns do not call into question his energy price forecasts. Natural gas prices and energy prices do not travel in lockstep, especially in Ohio where coal tends to be on the margin. Thus, as discussed below, Mr. Rose's energy price forecasts are relatively unaffected by changes in short-term gas prices.

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[107] ELPC Brief, p. 16.

[108] Sierra Club Brief, p. 24

[109] *See* Cleveland Brief, p. 7 (citing Kalt Second Supp., pp. 23-24).

a) Natural gas prices are extremely volatile.

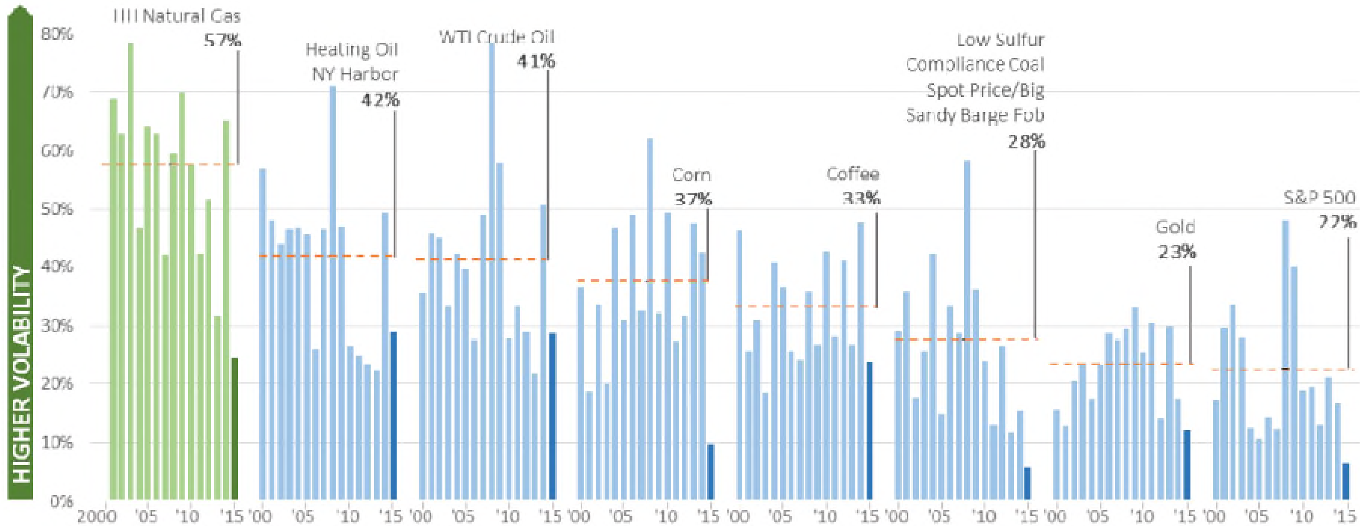
First, the criticisms of Mr. Rose on conditions and prices in the short-term natural gas market have at least one fatal flaw: they ignore the extreme volatility of natural gas prices. Mr. Rose, who understands natural gas price volatility, explained his lack of surprise at lower natural gas prices in the near term:

> Natural gas prices are especially volatile, and hence, neither periods with prices below the trend or above the trend are surprising. Indeed, of the most highly traded commodities on the NYMEX, including both energy and non-energy (including S&P 500, corn, coffee and gold), natural gas prices had the highest volatility on average from 2000 to 2015. The average natural gas price volatility was 57%, and the average of the eight other most highly traded commodities was 28.5%. The volatility of gas over the last ten years is 2.6 times the volatility of even the very volatile S&P 500 stock market index. Hence, deviations from average expected conditions are not un-common ….Sometimes gas prices are down (e.g., 2015) and sometimes they are up (e.g., 2013 and 2014). In addition, gas prices on the commodity level (*i.e.*, Henry Hub) can be up some, but delivered prices can be up even more. For example, delivered gas prices in parts of the northeastern U.S. during the 2014 Polar vortex reached the highest levels ever recorded in the U.S. of $120/MMBtu. Thus, extrapolating from [recent actual pricing] data to a 15 or 20 year projection is highly inappropriate.[110]

Mr. Rose illustrated the dramatic price volatility of natural gas, as compared to other commodities, in Figure 1 from his Rebuttal Testimony:

[110] Rose Rebuttal, pp. 30-31. *See also* Hearing Tr. Vol. Hearing Tr. Vol. VI, p. 1168 (Rose Cross).

Figure 1



Source: S&P 500 prices were obtained from Google Finance. Other prices were obtained from Bloomberg. 2015 reflects the trades as of 5/22/2015.

Mr. Rose explained the significance of this volatility comparison at hearing:

> Volatility refers to the frequency and extent of movement in the prices, so a volatile product would have a very dramatic movement in prices, and a nonvolatile product would have a relatively lower movement in prices. Often this is measured by statistics, known as -- which is the change -- percent change in a daily price, and that's the statistics I present in the document, would show that -- in my rebuttal testimony that would show that natural gas is the most volatile commodity, 2.6 times more volatile than the S&P 500. So it's extremely lots of movements in terms of percent change in price.[111]

Accordingly, there is no denying that natural gas is an exceptionally volatile commodity – a fact apparently not lost on Dr. Kalt, upon whom Cleveland relies here. At hearing, Dr. Kalt admitted that from December 16, 2016 to December 29, 2016, Henry Hub futures were 33 cents higher for 2016[112] and 14 cents higher for 2017[113] – a significant percentage increase in a very

[111] Hearing Tr. Vol. XXXV, p. 7327 (Rose Cross).

[112] Hearing Tr. Vol. XLI, p. 8673 (Kalt Cross).

short timeframe.[114] Such volatility also was not lost on Sierra Club witness Comings. At hearing, Mr. Comings admitted that Henry Hub spot prices, as reported in the EIA's Natural Gas Weekly Update, jumped 50% in the span of seven business days,[115] going from a low of $1.54 on December 24, 2015 to a high of $2.35 on January 6, 2016.[116]

Relying on December 2015 natural gas prices – which these intervenors apparently did to make their criticisms – was extremely short-sighted in light of the very mild weather which occurred. Indeed, December 2015 was the mildest December on record.[117] Mr. Comings further did not contest that there were record high natural gas inventories.[118] OCC/NOPEC witness Wilson likewise admitted that December 2015 was the warmest December on record[119] and, as a consequence, natural gas storage was very full.[120] Mr. Wilson further admitted that in December 2015, the natural gas market was vulnerable to low prices, due to very weak demand conditions.[121] Moreover, Mr. Wilson admitted that the low prices experienced in December 2015 should be considered *a very short-term condition.*[122]

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[113] Hearing Tr. XLI, p. 8673 (Kalt Cross).

[114] *See* Company Ex. 190 (NYMEX Henry Hub Futures (12/16/2015)) and 191 (NYMEX Henry Hub Futures (12/29/2015)).

[115] Hearing Tr. Vol. XXVIII, p. 8289 (Comings Cross).

[116] *See* Company Ex. 174 (EIA Natural Gas Weekly Update (01/06/2016)) pp. 4-5.

[117] Hearing Tr. Vol. XXXVIII, p. 8293 (Comings Cross) (reporting administratively notice weather data for December 2015 from the National Centers for Environmental Information of the National Oceanic and Atmospheric Administration).

[118] Hearing Tr. Vol. XXXVIII, p. 8294 (Comings Cross).

[119] Hearing Tr. Vol. XXXVIII, p. 8119 (Wilson Cross).

[120] Hearing Tr. Vol. XXXVIII, p. 8119 (Wilson Cross). *See also* January 2016 EIA STEO (Company Ex. 167) p. 10 (discussing record inventory levels for natural gas).

[121] Hearing Tr. Vol. XXVIII, p. 8121 (Wilson Cross).

[122] Hearing Tr. Vol. XXVIII, p. 8121 (Wilson Cross).

Notwithstanding the short-term volatility of natural gas prices, the impact of short-term volatility on Mr. Rose's long-term natural gas forecast is negligible. As Mr. Rose explained on redirect examination at hearing:

> Q. Mr. Rose, you were asked some questions about NYMEX gas prices for 2016 and to date 2015. You were also asked about your forecast for those years, and being -- or at least part of that period. And being that your forecast was 30 percent higher than the actual spot prices, what is the reason for that?
>
> A. I took a futures price. I used the futures price for the first two years for gas, so I took it from April -- May, April of 2014, and it turns out the futures price and the actual spot price, which actually go together, went down, and so that has resulted in a situation in which my gas price forecast is higher than the year-to-date number. However, *if I was to replace that with the most recent futures for the next two years*, it would not -- *on average it would be a moderate effect on my price forecast. It would bring me back down to the* -- *on average to the EIA levels.* It would have an even smaller -- *I am only 4 percent in real dollars higher than the EIA*, and it would bring my number approximately down to the EIA number if I adopted the most recent gas prices.[123]

Hence, given the extreme volatility of natural gas, natural gas prices on any particular day are not a sound basis to evaluate a long-term, methodologically sound natural gas forecast like Mr. Rose's.

Sierra Club also argues that Mr. Rose's natural gas forecast is outdated because ICF has lowered its own natural gas forecast since Mr. Rose generated his.[124] As the record evidence demonstrates, however, the forecasts of ICF and other major forecasting players show a long-term increase in gas prices. For example, Attachment JPK-SS – Confidential to the Second Supplemental Testimony of EPSA/P3 witness Kalt depicts several projections, including the EIA

[123] Hearing Tr. Vol. XXXV, pp. 7442-43 (Rose Redirect).

[124] *See* Sierra Club Brief, p. 24.

2015 Reference Case, that have natural gas prices steadily increasing over the long-term.[125] Hence, Sierra Club's argument is misplaced.[126]

Sierra Club also contends that ICF's other more recently published natural gas forecasts are lower than what Mr. Rose's forecasted here. Specifically, Sierra Club points to what it claims is an August 2015[127] ICF publication and notes that ICF's forecast then showed that gas prices didn't rise above $4/MMBtu until after 2018.[128] Sierra Club's report is selective and misleading. That report did not use assumptions selected solely by ICF, but included assumptions (particularly regarding carbon costs) requested by ICF's client in that matter.[129] Sierra Club also fails to report that the forecast then showed gas prices increasing to approximately $5/MMBtu in 2020 and $6/MMBtu in 2023.[130] Consistent with Mr. Rose's forecast here, ICF's forecasts there found support for those later year price levels through forecasts in increased natural gas demand (in the report, by 33% from 2015 to 2025).[131] In fact, the report's forecast for LNG exports (one potential driver of natural gas demand) is higher than Mr. Rose's forecast here.[132] Thus, the two forecasts, when viewed properly, are quite compatible.

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[125] *See* Attachment JPK-SS-1 Confidential Attached.

[126] The same could be said for any other forecast done by Mr. Rose or ICF, including his much discussed testimony in a case for Duke. Past forecasts likely show higher gas prices in the near term; but all show higher prices over time and all are fairly consistent with the trends of other well accepted forecasts, such as the AEO. Other forecasts for specific cases are also an inappropriate comparison, especially if the client in those cases gave ICF certain assumptions to include in the IPM. For example, Mr. Rose testified that he was specifically instructed by one client to use futures prices for more than two years. Hearing Tr. Vol. VII, p. 1437.

[127] The document is actually dated November 2015. Comings Third Supp., Ex. TFC-44.

[128] Sierra Club Brief, p. 17

[129] Comings Third Supp., Ex. TFC-44, p. 4.

[130] Comings Third Supp., Ex. TFC-44, p. 18.

[131] Comings Third Supp., Ex. TFC-44, p. 8.

[132] *Compare* Comings Third Supp. Ex. TFC-44, p. 9 *with* Rose Rebuttal, pp. 37-38.

b) Market fundamentals support long-term natural gas price increases.

Second, the better approach is to look at gas market fundamentals. Given the volatility of short-term natural gas markets, it makes sense to identify and consider market trends to understand the likely direction and magnitude of prices in the long term. Notably, the only witness who addressed these fundamentals was Mr. Rose. The fundamentals in the natural gas market show that natural gas supply is decreasing and natural gas demand is increasing.[133] Hence, natural gas prices should be expected to increase over the long term.[134] Notably, in drawing their cursory conclusions regarding Mr. Rose's natural gas forecasts, ELPC, Sierra Club and Cleveland simply ignore the undisputed evidence.

Several markers indicate that natural gas supply is decreasing. For example, producers are reducing exploration and production activity, in response to lower prices for natural gas, oil and Natural Gas Liquids ("NGLs"), which include propane.[135] Between June 2014 and July 2015: (1) gas (Henry Hub spot) prices have decreased by 40%; (2) oil (WTI, Brent) prices have decreased by 50%; and (3) propane (Mt Belvieu TX propane spot) have decreased by 61%.[136] Given these recent hydrocarbon price declines, the U.S. rig count has dropped by 55%.[137] Indeed, natural gas directed drilling is at its lowest level in the United States since 1985.[138] Since 2011, it has decreased approximately 75%.[139] "This is consistent with natural gas prices

[133] Rose Rebuttal, pp. 31-42.

[134] Rose Rebuttal, pp. 33, 36-37.

[135] Rose Rebuttal, p. 31.

[136] Rose Rebuttal, p. 31.

[137] Rose Rebuttal, p. 32.

[138] Rose Rebuttal, p. 32.

[139] Rose Rebuttal, p. 32.

being too low to meet future gas demand."[140] In turn, "current low prices cannot be sustained even if gas demand does not grow, because current low drilling levels mean that production will decline and exert upward pressure on prices."[141] Additionally, there is also a general decline in production-related spending, *e.g.*, planned exploration and production capital expenditures for 2015 are off their 2014 levels by approximately 35%.[142] This is another sign that current natural gas prices are too low to support the current level of demand.[143]

While supply decreases, gas demand is growing. As Mr. Rose explained:

> Between 2008 and 2015, natural gas demand in the U.S. increased by approximately 15% in spite of the Great Recession. Investments in export pipelines to Mexico, LNG export terminals, new petrochemical industry equipment, etc., are ongoing, and will increase U.S. gas consumption by one-third over the next ten years or approximately 9 TCF. This is as large as any ten year increase in gas demand in U.S. history. The only comparable period, from the early 1960s to early 1970s, resulted in widespread US gas shortages and the passage of the Fuel Use Act which banned new baseload gas power plants. I do not expect a repeat of the shortages, or the associated legislation, because the absence of price controls will allow the prices to increase. However, the demand growth makes the current lull in drilling is even less sustainable.[144]

Mr. Rose's Rebuttal Testimony demonstrates the upward trend in U.S. gas consumption in the following figure:

[140] Rose Rebuttal, p. 32.

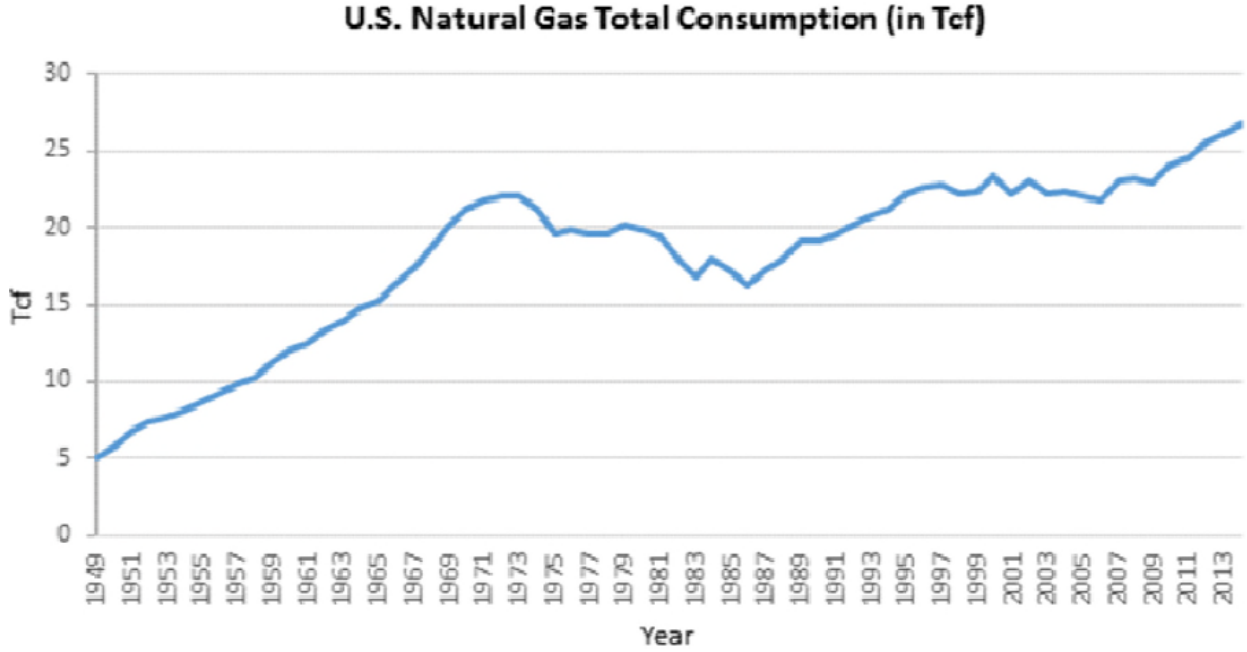
[141] Rose Rebuttal, p. 32.

[142] Rose Rebuttal, p. 36.

[143] Rose Rebuttal, p. 36.

[144] Rose Rebuttal, p. 36.

Figure 2



Such ever-increasing demand for natural gas, combined with its decreasing supply bode well for Mr. Rose's forecasts over the long-term. Once gas market fundamentals are properly taken into consideration, the compelling conclusion is that natural gas prices have nowhere to go over the long term but up.

Moreover, Mr. Rose explained that other natural gas forecasts, namely the 2014 and 2015 EIA AEO Reference Cases, similarly conclude natural gas prices will rise:

> I am not the only forecaster to conclude that in spite of low current gas prices, long term prices will rise…[The] EIA long term gas price reference cases are relatively stable and show large increases in prices from current levels. Furthermore, both EIA AEO reference cases (*i.e.*, 2014 and 2015) are [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[145]

Thus, Mr. Rose's natural gas forecasts are neither stale nor do they rely on outdated assumptions.

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[145] Rose Rebuttal, p. 39.

c) Short-term gas prices have ***de minimus*** effect on long-term energy prices.

Third, ELPC, Sierra Club and Cleveland fail to grasp that natural gas prices and energy prices do not move in lockstep. As Mr. Rose observed in his Rebuttal Testimony, recent decreases in natural gas prices have had a fairly limited impact on energy prices because coal has been the primary driver of electrical energy prices in Ohio:

> [T]he fact [is] that in most hours electrical energy prices in Ohio are set by coal generation not gas generation. As a result, recently lower than expected gas prices have therefore not led to equally lower electrical energy prices; the effects are much more muted.[146]

As Mr. Rose further testified at the hearing, recent decreases in natural gas prices have had a minor effect on energy prices:

> [The recent decease in natural gas prices] would have something on the order of a 1 or 2 percent effect on the average electrical energy price over the long term, because the gas price effect today on the electrical energy price is muted. Coals [sic] on the margin a lot, and it would have an even smaller effect, on the order of 1 to 2 percent under my average electrical energy price.[147]

Thus, given the moderate impact of natural gas prices on long-term electrical energy prices, the putative claims by ELPC, Sierra Club and Cleveland regarding Mr. Rose's natural gas forecasts are even more suspect. Indeed, for the reasons set forth above, such claims are meritless.

OMAEG contends that the Commission should follow the example of state commissions in Louisiana, Michigan and Nevada, which have rejected applications based on "stale" or "outdated" forecasts.[148] This erroneously assumes that Mr. Rose's forecasts are stale, which, as demonstrated above, is not the case. In any event, OMAEG's cases are distinguishable. In the

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[146] Rose Rebuttal, p. 13.

[147] Hearing Tr. Vol. XXXV, pp. 7443-44 (Rose Redirect).

[148] OMAEG Brief, pp. 57-58.

Louisiana matter,[149] Gulf States Utilities sought to recover costs relating to its decision to restart a nuclear plant. As the Louisiana Commission noted, "Gulf States made no substantial economic studies" and instead relied on "back of the envelope" studies.[150] In the Michigan matter,[151] a transmission company sought approval of a certificate of public convenience for a transmission line. The system peak load forecast relied upon by the Company to justify the new line exceeded MISO's and the Company's own internal forecast.[152] The Company provided no justification to use the difference the forecast presented in that case. Cases where the company failed to provide a study or failed to justify a study that varied from an RTO or internal forecast are inapposite here.

In the Nevada matter,[153] a utility sought approval for the construction of a transmission line and to enter into a purchase power agreement ("PPA"). Noting the significant upheaval in the Nevada economy starting in the latter part of 2007 and extending into 2009, the Nevada Commission observed that the utility had in fact updated its forecast. Recognizing that, in such a rapidly changing economic environment, "[t]he challenges these conditions impose to load forecasting are enormous," the Commission nevertheless found that the methodology used by the utility was adequate, but its forecast was too optimistic regarding the projected growth in the Nevada economy, and thus growth in load. Unlike the forecasts in the Nevada matter, the short-

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149 *In re Application for Approval of An Increase in Rates for Retail Service,* 1988 La. PUC LEXIS 2 (Nov. 15, 1988)

150 *Id.* at *8.

151 *In the matter of the application of INTERNATIONAL TRANSMISSION COMPANY, d/b/a ITCTRANSMISSION, for a certificate of public convenience and necessity for the construction of a transmission line running from and through Sterling Heights, Troy, Clawson, and Royal Oak, Michigan,* 2008 Mich. PSC LEXIS 43 (Feb. 22, 2008).

152 *Id.* at *7.

153 *Application of Nevada Power Company d/b/a NV Energy for approval of the eleventh amendment to the Action Plan of the 2007-2026 Integrated Resource Plan for Authority to construct the One Nevada Transmission Line; enter into a long-term power purchase agreement; approval of its updated fuel and purchased power forecasts and load forecast; and other matters related thereto,* 2009 Nev. PUC LEXIS 140 at *28 (July 22, 2009).

term variances between Mr. Rose's natural gas forecasts and realized gas prices do not call his forecast into question.

As Mr. Rose explained, updated natural gas futures prices have a *de minimus* effect on his energy prices over the longer term. And his forecasts agree with the trend seen in the only other independent forecasts in the record; namely, those in the EIA AEO.

(ii) There is no need for a "sensitivity analysis."

Some of Stipulated ESP IV's opponents contend that, even if Mr. Rose's forecasts are reliable, it would be unreasonable to rely on them because the Companies failed to provide any "sensitivity analysis." These parties make two mistakes. First, they contend that ICF was capable of doing such analysis here. This ignores Mr. Rose's evidence and misreads other alleged "similar cases" where ICF provided such information. Second, these parties complain that relying on a single forecast is unreasonable in light of the uncertainty inherent in forecasts. But this too ignores the record evidence, which shows that Mr. Rose's probability-weighted methodology directly addresses such concerns.

Contrary to the record evidence, Sierra Club maintains that ICF was more than capable of doing a sensitive analysis, such as a Monte Carlo analysis, in this proceeding but chose not to.[154] Nothing could be further from the truth. As Mr. Rose explained repeatedly to Sierra Club's counsel at the hearing, a sensitivity analysis was not practically feasible for the present case due to the extremely complex and numerous variables involved. In fact, Sierra Club's counsel essentially asked the same question *five* times regarding the feasibility of doing a sensitivity analysis here. Each time Mr. Rose patiently explained why it was *not* practically feasible to

[154] Sierra Club Brief, p. 40-41.

conduct sensitivity analyses for this case. The hearing transcript dramatically illustrates this point:

> Q. [Counsel for Sierra Club] Okay. But in this proceeding you've only presented a single capacity price for each year, correct?
>
> A. [Mr. Rose] Yes. Because it's a different problem just like the IRA, [sic, RIA] et cetera, when your problems get very, very complicated. You can't do it on a Monte Carlo basis. It would take years to do.
>
> Q. Okay.
>
> A. Because there are so many variables. It's not just flipping a coin. It's like you have 50 different variables to capture all the interactions, and you have to do it year by year, and that's why it's only used for very limited purposes in the near term.
>
> * * * * *
>
> Q. Okay. So is it your opinion that it would be infeasible to run some sort of a Monte Carlo simulation to determine in this proceeding a range of potential values for the likely costs and revenues for the Sammis plant?
>
> A. For -- my testimony is for the parameters I was asked to project, which are over 20 years a range of different parameters, I indicated here that the Monte Carlo simulation would probably take many years. And the reason for that is there are so many different variables that you have to take into account and you have to do a lot of trials and it covers many different years and many different parameters. Here we are just looking at a single -- the previous thing, we are just looking at a single number, but we are looking at a much more complicated set of variables. And as I indicate here, that's why in the analysis ICF does for the government, we don't have the sensitivity cases, much less the Monte Carlo one, and the reason for it is the complexity of the analysis doesn't lend itself to it.
>
> Q. So to do the Monte Carlo analysis for the gas price, energy price, coal price that you were asked to do in this proceeding, you are saying that would have been infeasible, correct?
>
> A. To do it for the set of projections that we were making, we were making hourly projections for 20 years for three locations for electric energy prices, we are taking into account all of the details of the interaction of gas prices, and for the whole Eastern

> Interconnect, that is an extremely complicated problem. And so it's not feasible to do that on a Monte Carlo basis, and I have never seen it done. And, as I indicated, in the analyses that are the most significant analyses that the government is doing, they are doing one scenario as well.[155]
>
> * * * * *
>
> Q. Mr. Rose, do you -- so your testimony on page 9 of your rebuttal testimony, page 9, line 17 through line 8 on page 10, discusses your opinion that it is not feasible to do Monte Carlo -- Monte Carlo simulations for the forecasts that you made in this proceeding, correct?
>
> A. Yes. And you can see that on line 23, 24 where each run would require me to run MAPS and IPM, each of which takes four to six hours. And I also expressed the possibility that to do that requires as much as 5,000 runs and somewhere between 4.6 and 6.8 years.
>
> Q. And so your testimony regarding the feasibility of doing Monte Carlo simulations is limited solely to the forecasts of gas prices, coal prices, electric energy prices, and CO-2 prices that you provided in this proceeding; is that right?
>
> A. Yes. But, of course, those forecasts are associated with lots of other parameters and forecasts and calculations, and that's what makes it infeasible. It's millions of different variables that are involved.[156]

The transcript shows that Mr. Rose repeatedly testified that, a sensitivity analysis was not practically feasible here. Notably, no witness contradicted Mr. Rose regarding the feasibility of a sensitivity analysis given the complex and multi-variabled nature of the model and study done here.

Given the lack of any expert testimony to contradict Mr. Rose's testimony on this point, Sierra Club points to a sensitivity analysis that Mr. Rose did for a client as part of his

[155] Hearing Tr. Vol. XXXV, pp. 7273-75 (Rose Cross).

[156] Hearing Tr. Vol. XXXV, p. 7278 (Rose Cross).

involvement in a case before the Arkansas Public Service Commission.[157] In the Arkansas case, Mr. Rose used only a single model (IPM) to look at a number of scenarios relating to an environmental compliance plan for a single coal-fired generating plant in the Southern Power Pool ("SPP").[158] In the instant matter, Mr. Rose used *three* models (IPM, GE-MAPs and GMM) to forecast prices relating to multiple units at the Plants and the OVEC facilities in PJM, a much larger market.[159] A zonal pricing analysis (like that used in the Arkansas case and in ICF's quarterly forecasts) is amenable to sensitivity cases.[160] A study using nodal pricing (like was the case here) does not. As Mr. Rose explained, his study here had to analyze thousands of pricing nodes and produce hourly prices at each node.[161] That is a level of complexity orders of magnitude beyond the exercise in Arkansas.

ELPC, apparently attempting to rebut the evidence regarding the infeasibility of a sensitivity analysis, as well as Mr. Rose's testimony that sensitivity analyses were not used for ICF's Regulatory Impact Analyses ("RIAs") conducted for U.S. EPA, argues that in the very same RIAs in which ICF's IPM was used, sensitivity analyses were performed.[162] ELPC overlooks that these sensitivity analyses related to environmental and health benefits, not to prices, costs and similar data.[163] In short, ELPC fails to understand the materially different contexts in which sensitivity analyses were performed.

As Mr. Rose explained in his Rebuttal Testimony, for various RIAs in which ICF was involved for U.S. EPA, there were no economic sensitivity cases done because of the level of

[157] *See* Sierra Club Brief, p. 27.

[158] Sierra Club Ex. 9, p. 5.

[159] Rose Direct, pp. 44; 46.

[160] Hearing Tr. Vol. VII, pp. 1488-1490 (Rose Cross).

[161] Hearing Tr. Vol. VII, pp. 1488-1490 (Rose Cross); Hearing Tr. Vol. VII (CONF), pp. 1343-1344 (Rose Cross).

[162] ELPC Brief, p. 29. *See* Rose Rebuttal, pp. 12-13.

[163] ELPC Brief, p. 29.

complexity and broad scope of analysis, similar to what was done here.[164] Mr. Rose was not involved in any sensitivity analyses relating to expected environmental and health benefits, and these analyses were unrelated to Mr. Rose's work.[165] Mr. Rose's testimony demonstrates the utter irrelevance of the benefits analysis in the RIAs to what ICF did:

> EXAMINER PRICE: I just have to ask a follow-up, just so the record is clear. What you are -- tell me if my understanding of your testimony is incorrect. On page 13, at line 2, when you testify about economic sensitivities for these three EPA rules, you were solely testifying as to the outputs regarding energy prices coming from your modeling that goes into whatever other analysis the U.S. EPA does; is that correct?
>
> A. [Mr. Rose] Yes. In the sense that everything you said was correct, but it wasn't just energy price, it was things like what are power plants doing, their performance and characteristics, other prices, et cetera. But it wasn't really related to any of this material [*i.e.*, the benefits analysis at issue], which is very removed from the work that we are doing with IPM, for example.[166]

Mr. Rose also noted that the benefits analysis to which ELPC's counsel alluded was fairly simplistic and could "be done on a spreadsheet type of model."[167] In contrast, the IPM economic analysis conducted for the RIAs (and for the Companies here) was much more complex:

> That modeling reflects decades of activity, and the modeling is quite sophisticated, and it involves things called linear programming, optimization models, and it's a sophisticated treatment of the grid, and because it's very complicated, it tends to be a single case for -- although they may look at different regulations. So it's a different activity. It's modeled differently, involves different parameters, involves different modeling tools, different mathematical techniques, and as I indicated, it has generally one set of economic assumptions in the RIAs and one or more regulatory regimes, and that's different than all of the dose-

[164] Rose Rebuttal, p. 12.

[165] Hearing Tr. Vol. XXXV, p. 7316 (Rose Cross).

[166] Hearing Tr. Vol. XXXV, p. 7316 (Rose Cross).

[167] Hearing Tr. Vol. XXXV, p. 7451 (Rose Redirect).

> response and other benefits of the calculations that were in the materials sent to me that don't involve large lineal programming models.[168]

Thus, ELPC fails to draw parallels between the simplistic studies in which sensitivity analyses were performed and Mr. Rose's complex study for this case.

Sierra Club also argues that it was "egregious" for the Companies to have failed to carry out sensitivity analyses because the Companies' "own witnesses acknowledge that there is significant uncertainty regarding key inputs, such as forecasted energy prices and capacity prices."[169] However, Sierra Club's argument ignores the law of large numbers, which Mr. Rose explained:

> Q. [Counsel for Sierra Club] So in any given year, market energy prices could be significantly lower than what you're projecting in this proceeding; is that right?
>
> A. [Mr. Rose] It could be significantly lower, and they could be significantly higher. I did want to emphasize something that may not be common understanding of what's involved in forecasting. It's true you have a better near term view of what's likely to happen because you have more information about the near term than the long term. One would conclude potentially that forecasting next year or the year after has less uncertainty than in the long run. But in the long run, you have the law of large numbers working for you. So you have multiple trials or multiple years, and so what happens is you have less variability in the forecast. So it's like trying to estimate what's the chance of flipping a coin and getting a heads. If you just have one or two years, the near term, and you get two tails, you would conclude you never have a chance of getting a heads. Whereas, when you are forecasting for the long run, you'll know that you are going to get information about flipping a coin and also what the long term average price is going to be.[170]

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[168] Hearing Tr. Vol. XXXV, pp. 7451-52 (Rose Redirect).

[169] Sierra Club Brief, p. 42.

[170] Hearing Tr. Vol. VI, pp. 1145-46 (Rose Cross). Notably, Counsel for Sierra Club moved to strike Mr. Rose's response which the Bench denied. Indeed, in denying the motion to strike, the Attorney Examiner went so far as to comment: "I am going to deny your motion to strike because I found [Mr. Rose's] answer to be very interesting and useful to the Commission." Hearing Tr. Vol. VI, p. 1146 (Rose Cross).

The law of large numbers demonstrates that isolated uncertainty in the context of a long-term price forecast does not warrant a sensitivity analysis. Combined with the practical infeasibility of conducting sensitivity analyses addressed above, the law of large numbers, as applied to the present context by Mr. Rose, should put to rest Sierra Club's claims regarding the need for a sensitivity analysis.

Further, those advocating for "sensitivity analyses" fail to understand that the purpose of such analyses is to deal with potential uncertainties regarding the outcome of the forecast. For example, Sierra Club's view no doubt reflects the views of its witness, Mr. Comings. He tried to show a sensitivity analysis by showing a range of energy prices and how those projections might impact Rider RRS.[171] But Mr. Comings admitted that his range of energy prices was based more on his arbitrary "judgment," *i.e.*, not based on any empirical forecast or model.[172] In contrast, Mr. Rose testified that his model already factors in uncertainty. As Mr. Rose explained in his Rebuttal Testimony:

> My treatment [of uncertainty] is the same as the treatment in ICF's Regulatory Impact Analysis ("RIA") of the Clean Power Plan conducted for the U.S. EPA using its assumptions. I provided a probability-weighted projection also referred to as an 'Expected Value' forecast, which is the key basis for decision making.[173]

This probability weighting, based on considered modeling, takes uncertainty and the range of possible outcomes into account.[174]

In summary, the handful of intervenors hoping to challenge Mr. Rose's energy price forecast have failed to produce any probative evidence that his forecast is unreasonable. And their attempts to undercut his natural gas price forecast as a proxy for his energy price forecast

[171] Comings Direct, p. 10.

[172] Hearing Tr. Vol. XXXI p. 6493-6494 (Comings Cross).

[173] Rose Rebuttal, p. 9.

[174] Rose Rebuttal, p. 10.

fail for the reasons above. Thus, the Companies reasonably relied on Mr. Rose's energy price forecasts to project the $561 million benefit to customers from Rider RRS.

c. **Mr. Rose's capacity forecasts are appropriate and reliable.**

In his Direct Testimony, Mr. Rose forecasted increases in capacity prices.[175] Mr. Rose based this projection on, among other things, the then-forthcoming (now mostly realized) FERC reforms of PJM's capacity market including the CP Order.[176] By any measure, Mr. Rose's capacity price forecast has held up extremely well:

- On August 10, 2015, the 2018/2019 PJM Base Residual Auction (BRA) CP capacity price increased from $120/MW-day to $165/MW-day (+38%); $165/MW-day was the second highest RTO capacity price.[177]

- On August 27, 2015, the PJM incremental transition auction increased the RTO CP capacity price from $60/MW-day to $134/MW-day (+123%).[178]

- On September 3, 2015, PJM held a second incremental transition auction for 2017/2018 procurement in which the RTO CP capacity price increased from $120 to $152/MW-day (+27%).[179]

There is evidence that capacity prices will go even higher as the CP requirements come into effect. For example, certain zones within PJM have capacity prices nearing offer caps:

- The COMED (a PJM sub-zone to the west of the RTO zone) BRA 2018/2019 CP capacity price was $215/MW-day (+79%); this was the first time the COMED price separated from the RTO price. This is the highest price ever recorded for this capacity zone and is evidence of the potential for PJM capacity prices in western PJM to exceed $200/MW-day.[180]

- The East MAAC (a PJM sub-zone to the east of the RTO zone) BRA 2018/2019 CP capacity price increased to $225/MW-day in the 2018/2019

[175] Rose Direct, p. 5.

[176] Rose Rebuttal, p. 20.

[177] Rose Rebuttal, p. 21.

[178] Rose Rebuttal, p. 21.

[179] Rose Rebuttal, p. 22.

[180] Rose Rebuttal, p. 22.

> BRA (+88%). This price was 99% of the bid cap, and hence, is evidence that PJM capacity prices can reach the offer price cap.[181]

At hearing, Mr. Rose testified to the similarities between the impacts of CP and his forecasts:

> So, for example, the BRA, the base residual auction went from 120 to 165. The RTO price in the transition auction went from 60 to 134. We've seen increases in capacity prices around all markets with capacity, New England, New York, PJM, and MISO. That's what we forecast in 2014, that there would be significant increases, and they are afoot.[182]

Just as Mr. Rose forecast, capacity prices have increased significantly across the board, in PJM as a whole and in various sub-zones. Nevertheless, various intervenors have sought to criticize Mr. Rose's capacity price forecast. As demonstrated below, these criticisms fall flat.

ELPC, Sierra Club and OMAEG argue that PJM has lowered its load forecasts for 2016, which allegedly will lead to downward pressure on capacity prices, and that Mr. Rose's load projections are higher than PJM's new projections.[183] To the contrary, a critical review of PJM's load forecast reports support the reliability of Mr. Rose's forecast. In fact, the criticisms of Mr. Rose's capacity forecast are particularly misleading because they fail to account for the difference between unrestricted and restricted peak load.[184]

PJM's 2016 load forecasts contain projections for both gross or "unrestricted" peak as well as for net or "restricted" peak load.[185] "Unrestricted Peak," as defined by PJM, is "peak

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[181] Rose Rebuttal, p. 22.

[182] Hearing Tr. Vol. VI, p. 1196 (Rose Cross).

[183] *See* Sierra Club Brief, p. 35-36; ELPC Brief, p. 18-19; OMAEG Brief, p. 40-41.

[184] Indeed, OMAEG witness Seryak, one of Mr. Rose's capacity price forecast critics, admitted that at the time he drafted his testimony, he "did not go down in to the differences between restricted and unrestricted load." Hearing Tr. Vol. XL, p. 8439 (Seryak Cross).

[185] Company Exhibits 170 (January 2015 PJM Load Forecast Report) and 171 (January 2016 PJM Load Forecast Report) contain "restricted" and "unrestricted" 15-year summer forecasts regarding Demand Resources for the PJM RTO. *See* Company Ex. 170 p. 61, Table B-7, and Company Ex. 171 p. 65, Table B-7. The Notes to Table B-7 in the 2015 PJM Load Forecast Report state "Forecast represents the amount of Demand Resources committed to the PJM Reliability Pricing Model via RPM Auctions (including incremental auctions) and FRR Capacity Plans." Company Ex. 170 p. 61, Notes. Likewise, the Notes to Table B-7 in the 2016 Load Forecast Report state: "DR

load prior to any reduction for load management [*i.e.*, mainly demand response], accelerated energy efficiency or voltage reduction."[186] The restricted peak is therefore derived by subtracting demand response and energy efficiency from the unrestricted peak. As Mr. Comings admitted, the "restricted" number would be the load that generation (*i.e.*, "in the ground") resources have to meet.[187]

As Sierra Club's own witness agreed, the demand response reflected in PJM's 2016 forecast was less for each year than the amount of demand response reflected in the 2015 report.[188] Thus, as shown in Figure 3 below, the amount of peak load that generation would need to serve, PJM RTO restricted peak, has not significantly changed and hence would not lead to downward pressure on capacity prices.

Forecast accounts for the transition from Limited, extended summer and Annual DR to Base and Capacity Performance (CP) DR in Delivery Year (DY) 2018 then to only CP DR 2020"and further, "DR forecast is based on the average ratio of committed DR (by DR product) to past forecasted peak in the last 3 DYs (2013, 2014, 2015) multiplied by the forecasted summer peak in Table B-1." Company Ex. 171 p. 65, Notes. By any measure, in both reports Table B-7 is a forecast. At the hearing, however, OCC/NOPEC witness Wilson refused to acknowledge that Table B-7 was a forecast, even though, in both instances, he admitted that it is identified by PJM as a "forecast" in the relevant Notes. *See* Hearing Tr. Vol. XXXVIII, p. 8132 (Wilson Cross). Mr. Wilson's failure to admit that Table B-7 in both reports is a genuine forecast is belied by PJM Manual 19, Load Forecasting and Analysis (Revision 29, Effective Date: 12/1/2015) (Company Ex. 172). PJM Manual 19 conclusively demonstrate that Table B-7, in both instances, counts as a forecast. At the bottom of page 12, under "Load Management…," the manual states: "PJM incorporates the assumptions of load management, energy efficiency, price responsive demand and behind-the-meter generation to supplement the base unrestricted, forecast." On page 13, PJM Manual 19 lays out the methodology whereby such forecasts are generated. Tracking both instances of Table B-7, PJM Manual 19 explicitly states: "The forecast is based on the PJM final summer season Committed DR amount, where the Committed DR means all DR that has committed through RPM, Base Residual Auction and all Incremental Auctions, or a Fixed Resource Requirement plan." Company Ex. 172 p. 13. The manual requires that a three-step procedure be followed to generate the Load Management forecasts at issue. *See id.* Subsequent to presenting the Load Management forecasting methodology, PJM Manual 19 notes: "The total amount of behind-the-meter solar generation will be forecasted separately from the load forecast model." *Id*.. At hearing, Mr. Wilson admitted that PJM Manual 19 contained the above. *See* Hearing Tr. Vol. XXXVII, pp. 8133-35 (Wilson Cross). Hence, Mr. Wilson's refusal to acknowledge that both instances of Table B-7 are genuine forecasts is inexplicable and more evidence of his lack of credibility.

[186] *See* Company Ex. 171 (PJM Load Forecast Report, January 2016), at "Terms and Abbreviations Used in This Report."

[187] Hearing Tr. Vol. XXXIX, p. 8301 (Comings Cross).

[188] Hearing Tr. Vol. XXXIX, p. 8304 (Comings Cross).

Figure 3[189]

Summer Peak Load (MW) and Growth Rates for PJM RTO										
	PJM Unrestricted Peak (Table B-1)				Energy Efficiency and Load Management		PJM RTO Restricted Peak (Summary Table)			
Year	January 2015	January 2016	Change	% Change	January 2015 (Table B-8)	January 2016 (Table B-7)	January 2015	January 2016	Change	% Change
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			(C)-(B)	(D)/(B)			(B)-(F)	(C)-(G)	(H)-(I)	(J)/(H)
2016	157,912	152,131	(5,781)	-3.7%	13,683	8,777	144,229	143,354	(875)	-0.6%
2017	159,808	154,149	(5,659)	-3.5%	12,335	8,883	147,473	145,266	(2,207)	-1.5%
2018	161,128	155,913	(5,215)	-3.2%	12,335	8,977	148,793	146,936	(1,857)	-1.2%
2019	162,618	156,958	(5,660)	-3.5%	12,335	9,035	150,283	147,923	(2,360)	-1.6%
2020	164,443	156,887	(7,556)	-4.6%	12,335	3,416	152,108	153,471	1,363	0.9%
2021	165,764	157,358	(8,406)	-5.1%	12,335	3,424	153,429	153,934	505	0.3%
2022	166,902	157,986	(8,916)	-5.3%	12,335	3,436	154,567	154,550	(17)	0.0%
2023	168,399	158,975	(9,424)	-5.6%	12,335	3,450	156,064	155,525	(539)	-0.3%
2024	169,706	159,991	(9,715)	-5.7%	12,335	3,478	157,371	156,513	(858)	-0.5%

As Figure 4 below demonstrates, energy efficiency and load management (demand response) for ATSI were greatly reduced for all years between PJM's 2015 and 2016 reports. In fact, aside from the reductions in energy efficiency and demand response, PJM's 2016 load forecast is actually projecting *growth* in ATSI's restricted peak load during the term of Stipulated ESP IV, as demonstrated in Figure 4:

[189] All data in Figure 3 is from the January 2015 and January 2016 Peak Load Reports (Company Exs. 170 and 171).

Figure 4

Summer Peak Load (MW) and Growth Rates for ATSI										
	ATSI Unrestricted Peak (Table B-1)				Energy Efficiency and Load Management		ATSI Restricted Peak			
Year	January 2015	January 2016	Change	% Change	January 2015 (Table B-8)	January 2016 (Table B-7)	January 2015	January 2016	Change	% Change
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			(C)-(B)	(D)/(B)			(B)-(F)	(C)-(G)	(H)-(I)	(J)/(H)
2016	13,369	12,921	(448)	-3.4%	1,932	786	11,437	12,135	698	6.1%
2017	13,443	13,004	(439)	-3.3%	1,109	791	12,334	12,213	(121)	-1.0%
2018	13,458	13,089	(369)	-2.7%	1,109	796	12,349	12,293	(56)	-0.5%
2019	13,499	13,149	(350)	-2.6%	1,109	799	12,390	12,350	(40)	-0.3%
2020	13,581	13,129	(452)	-3.3%	1,109	310	12,472	12,819	347	2.8%
2021	13,636	13,158	(478)	-3.5%	1,109	311	12,527	12,847	320	2.6%
2022	13,691	13,207	(484)	-3.5%	1,109	312	12,582	12,895	313	2.5%
2023	13,748	13,236	(512)	-3.7%	1,109	312	12,639	12,924	285	2.3%
2024	13,764	13,313	(451)	-3.3%	1,109	314	12,655	12,999	344	2.7%

Comparing Mr. Rose's and PJM's restricted load forecasts for the PJM RTO shows that they are fairly close. For example, as evidenced in his public workpapers, Mr. Rose predicted an unrestricted peak of 170,026 MW for the PJM RTO in year 2021.[190] For that same year, Mr. Rose predicted that demand response would be 11,366 MW of peak and that energy efficiency would be 1,386 MW of peak.[191] If those numbers are subtracted from Mr. Rose's unrestricted peak load projection for 2021, Mr. Rose's restricted peak for the PJM RTO in 2021 is 157,274 MW.[192] PJM's 2016 forecast for restricted peak in 2021 is 153,934.[193] As Mr. Comings admitted, Mr. Rose's restricted peak is within three percent of PJM's 2016 restricted peak number.[194]

[190] Company Ex. 176 (Public Workpapers of Judah Rose), p. 3; Hearing Tr. Vol. XXXIX, p. 8307 (Comings Cross).

[191] Company Ex. 176, p. 4; Hearing Tr. Vol. XXXIX, pp. 8307-08 (Comings Cross).

[192] Hearing Tr. Vol. XXXIX, p. 8308 (Comings Cross).

[193] Company Ex. 171, p. 3.

[194] Hearing Tr. Vol. XXXIX, pp. 8308-09 (Comings Cross).

In fact, Sierra Club's brief makes the Companies' point. On Table 6 of its brief, Sierra Club shows that the difference between Mr. Rose's forecast and PJM's forecast for restricted load varies between 1.5 and 4.5%.[195] But as Mr. Comings further admitted **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from one another. [196]

Both Sierra Club and ELPC compare the clearing price of $164.77/MW-day in the PJM 2018/19 BRA to Mr. Rose's capacity price forecast of [**BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for that delivery year and argue the difference justifies discarding Mr. Rose's forecast.[197] The difference in these figures is unremarkable and shows only that Mr. Rose was off by the timing of the CP requirements, but (more importantly) not about the effects of those requirements. In 2015, PJM published a "Scenario Analysis for the 2018/2019 BRA."[198] One of the scenarios reviewed, Scenario 13, indicated that if the 2018/2019 BRA results had had a 100 percent CP product requirement, instead of only 80 percent, the 2018/2019 BRA capacity price in the ATSI zone would have been $236.67/MW-day – approximately $70 higher per MW-day than what actually occurred.[199]

Accordingly, while Mr. Rose's capacity forecast may have predicted the CP requirements would take effect more quickly than they did, his forecast about the *effect* of those requirements was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. PJM's forecast

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[195] Sierra Club Brief, p. 36.

[196] Hearing Tr. Vol. XXXI (Confidential), p. 6494 (Comings Cross).

[197] Sierra Club Brief, p. 31; ELPC Brief, p. 2.

[198] Company Ex. 169. This was authenticated by OCC/NOPEC witness Wilson. Hearing Tr. Vol. XXII, p. 8123 (Wilson Cross).

[199] Hearing Tr. Vol. XXII, pp. 8123-28 (Wilson Cross); *see* Company Ex. 169, Scenario 13.

under Scenario No. 13 is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than Mr. Rose's with a full CP requirement.[200]

Sierra Club erroneously claims that the recent ruling in *Federal Energy Regulatory Comm. v. Elec. Power Supply Assoc.* ("*EPSA*"),[201] which upheld FERC's jurisdiction to promulgate rules relating to the bidding of demand response resources into PJM markets, will create downward pressure on capacity prices.[202] While Mr. Rose testified that the exclusion of demand response would have added additional upward pressure to capacity prices, the effects of new demand response alone will be unlikely to lead to any significant drop in capacity prices in the immediate future, because they will be outweighed by upward pressure on capacity prices caused by the transition to a full CP requirement.

As explained above, capacity prices steeply increased in 2015, in line with Mr. Rose's forecast: the 2018/2019 PJM BRA CP capacity price experienced a 38 percent increase to \$165/MW-day.[203] As Mr. Rose stated in his Rebuttal Testimony, the main driver of significant recent capacity price increases was the recent adoption of the CP requirement by PJM:

> These increases were associated with partial implementation of the CP Order. The share of capacity purchased as CP product (as opposed to Base Capacity which is not subject to the new CP rules) was 60%, 70% and 80% in the three auctions held in August through September). PJM is scheduled to purchase 100% CP capacity starting in the 2020/2021 delivery period. The first 100% CP BRA occurs in May 2017. At that time, demand will increase

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[200] Sierra Club attempts to question the integrity of PJM's Base Scenario Analysis, claiming that PJM "provided no explanation for how the capacity price was projected" for Scenario No. 13. Sierra Club Brief, p. 33, n. 109. This argument is belied by the numerous exhibits from PJM that have been admitted into evidence during the course of the hearing. Indeed, Sierra Club itself has introduced into evidence various materials from PJM (e.g., Sierra Club Ex. 8, PJM's 2014 Polar Vortex Report) to which the Companies had no objection. Hence, Sierra Club's claim here falls flat. As Company Exhibit 169 demonstrates, on PJM's full CP requirement analysis, Mr. Rose's capacity price forecast is right on target. Sierra Club and ELPC's attempt to show otherwise is meritless.

[201] 136 S. Ct. 760 (2016).

[202] *See* Sierra Club Brief, pp. 17, 36, n. 123.

[203] Rose Rebuttal, p. 21.

> for CP product by 25% (100% divided by 80%), due to full implementation of the CP program. Thus, even greater price increases are expected.[204]

The upward pressure on capacity prices caused by the transition to a full CP requirement will likely more than counteract any downward pressure from DR.[205] Sierra Club's argument falls flat.

Sierra Club also contends that an ICF publication entitled "New Regime, New Results, Insights from Recent PJM Auctions,"[206] had taken the view that there was a "plausible scenario" that capacity prices would decrease (or at least be less than Mr. Rose forecasts here).[207] Sierra Club misreads the document and wholly ignores Mr. Rose's explicit testimony regarding the meaning of the ICF document. The ICF paper was written to PJM market participants to work with ICF to help those entities with their bidding strategies.[208] The discussion that references a "plausible scenario" illustrates the operation of a short-term modeling tool recently developed for

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[204] Rose Rebuttal, pp. 22-23. *See also* Hearing Tr. Vol. XXXV, pp. 7444-45 (Rose Redirect).

[205] This is why. In its 2016 Load Forecast Report, PJM forecasts approximately 3,400 MW of demand response for the summer of 2020, a decrease from approximately 12,000 MW of demand response from January 2015 PJM Load Forecast Report for the same period. *Compare* Cos. Ex. 171, p. 70, Table B-7 *with* Sierra Club Ex. 15, p. 3, Summary Table. The forecasted decrease in demand response of approximately 70% (from 12,000 to 3,500 MW) occurred after FERC's decision in *In re PJM Interconnection, L.L.C.,* FERC Docket No. ER15-623-000, Order on Proposed Tariff Revisions (June 9, 2015), which decreased the ability of demand response to compete in the capacity market.

In turn, the impact of going from an 80% CP product to a 100% CP product in the forecasted year 2020 is likely to increase CP demand by approximately 36,000 MW. The 36,000 MW is 20% of the unrestricted demand response projected in the 2016 PJM forecast for summer 2020 (157,000 MW (Cos. Ex. 171, Table B-1, p. 52) plus a reserve target level of 15.7% (Cos. Ex. 176 (Rose Public Workpapers)). Thus, in order for demand response to offset the anticipated CP product demand increase of 36,000 MW in 2020, demand response would have to increase from approximately 3,400 MW to 39,400 MW (36,000 + 3400), which is highly unlikely to occur. To put this into perspective, the 36,000 MW is three times the amount of DR from 2015 and three and one-half times the amount of DR from 2014. Sierra Club Ex. 15, p. 3, Summary Table (approximately 12,000 MW); Cos. Ex. 75 (PJM State of Market Q1 2014), p. 211 (approximately 10,000 MW). The quantities from both of these years, however, were before DR participation was impacted by *In re PJM Interconnection, L.L.C.*

[206] *See* Sierra Club Ex. 87.

[207] Sierra Club Brief, p. 37.

[208] Hearing Tr. Vol. XXXV, pp. 7267-69 (Rose Cross).

deriving and understanding bidding strategies.[209] The scenario discussed was not labeled as "probable" or "expected," but merely as "illustrative" and "plausible."[210] Further, as Mr. Rose also testified, the assumptions explicitly stated for the "illustrative" or "plausible" scenario were "conservative" or "low end" and would have been so regarded by the paper's intended audience.[211] For example, the scenario assumed that bidders would not raise their bids closer to the offer caps,[212] an unlikely occurrence (indeed, in other regions, such increased bids were being seen already).[213] Thus, the ICF paper is in no way inconsistent with Mr. Rose's capacity price forecasts.

Sierra Club also argues that history contradicts Mr. Rose's capacity forecast. Specifically, it says, "there has never been a situation [in PJM] where the capacity price went up or down more than three years in a row. Yet, the Companies are projecting that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**"[214] This argument does little more than reveal Sierra Club's failure to understand the nature of forecasts.

Forecasts are very useful because they can help to identify market trends, *i.e.*, what is likely to happen, on average, over time. After all, forecasts are tools to deal with uncertainty – in the present context, the likely trajectory of PJM capacity prices several years into the future. Mr. Rose relied on two sophisticated computer models to generate his capacity forecast, GE MAPS and IPM. Using these sophisticated models, Mr. Rose was able to generate a probability-

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[209] Hearing Tr. Vol. XXXV, p. 7271 (Rose Cross).

[210] Hearing Tr. Vol. XXXV, p. 7267 (Rose Cross).

[211] Hearing Tr. Vol. XXXV, pp. 7270-7271 (Rose Cross).

[212] Hearing Tr. Vol. XXXV, p. 7269; Sierra Club Ex. 87, p. 11.

[213] Hearing Tr. Vol. XXXV, pp. 7248-7249 (Rose Cross).

[214] Sierra Club Brief, p. 38.

weighted forecast for capacity prices. "Probability weighting incorporates uncertainty and *the relative likelihood of a range of outcomes*." Thus, Mr. Rose relied on these models to forecast an "average" capacity price over a twenty-year period, which, he determined showed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[215]

What matters, however, is the average and trend of the prices. Forecasting natural gas prices provides a case in point. As Mr. Rose observed, "Natural gas prices are especially volatile, and hence, *neither periods with prices below the trend or above the trend are surprising*."[216] As Mr. Rose explained at hearing, when dealing with a forecast for a particular year:

> I think the best way to think about it is in a given year if you repeated that year many times, you should get that number. And so if you are looking at it over a long term period of time, you should tend towards that number, but each individual outcome you want could be plus or minus above that.[217]

ELPC criticizes Mr. Rose for "project[ing] a constant level of energy efficiency of 0.8% energy savings per year through 2024" and for ignoring the impact of the Clean Power Plan ("CPP") on energy efficiency.[218] ELPC contends that the "failure to capture increasing levels of energy efficiency is likely to understate future load reductions in light of existing Ohio law that requires specific energy savings achievements through 2027 that may be greater than historical trends, as well as federal policy in the form of the CPP that may drive even more "accelerated" energy efficiency deployment."[219] ELPC is wrong on both counts.

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[215] *See* Rose Direct, p. 6.

[216] Rose Rebuttal, p. 30 (emphasis added).

[217] Hearing Tr. Vol. XXXV, p. 7329 (Rose Cross).

[218] ELPC Brief, pp. 19-20.

[219] ELPC Brief, p. 20.

As a general matter, given that the CPP has been stayed by the United States Supreme Court, it is highly unlikely that there will be any "'accelerated' energy efficiency deployment" for the foreseeable future as a result of the CPP.[220] Further, ELPC ignores the fact that Mr. Rose's modeling was not exclusively Ohio-focused. The 0.8% level applies to energy efficiency that qualifies for the PJM capacity market.[221] While the sophisticated ICF models employed by ICF factored in the PJM zones and subzones that comprise Ohio, these models did so as part of the entirety of PJM (and beyond). For example, as Mr. Rose explained in his Direct Testimony, the ICF IPM model "captures a detailed representation of all electric boilers and generators in the North American power markets."[222]

Regarding the modeling of energy efficiency programs, Mr. Rose explained, "Energy efficiency and demand side management programs are evaluated in an integrated framework with other resource options."[223] When asked about this at hearing, Mr. Rose explained:

> The model can make a decision in terms of what resources are optimal. The integration is that you're integrating a consideration of, for example, a supply side resource with a demand side resource. The most common demand side resource in PJM is interruptible load, but there is also energy efficiency programs. So it depends on the particular application. But as a general matter, you could consider both supply and demand resources on equal footing. It takes into account their actual characteristics in terms of being able to provide for meeting the demands and need for capacity and energy.[224]

[220] *See Chamber of Commerce v. EPA*, No. 15A787, Misc. Order (U.S. S. Ct. Feb. 9, 2016) (staying effective date of CPP).

[221] *See* Company Ex. 20 (Rose Confidential Workpapers) at 1-2.

[222] Rose Direct, p. 45.

[223] Rose Direct, p. 46.

[224] Hearing Tr. Vol. VI at 1255 (Rose Cross).

Mr. Rose modeled demand response and energy efficiency for the entirety of PJM over a multi-year period.[225] Thus, the electricity demand of Ohio is small relative to the total PJM demand being modeled. In turn, greater energy efficiency reductions in Ohio would have a limited impact on energy demand, energy prices and the revenues of power plants in PJM as a whole.

Mr. Rose has, very successfully so far, identified an upward trend in capacity prices. Unlike any intervenor witness to this proceeding, Mr. Rose has done so using market fundamentals and very sophisticated and well-recognized models. Thus the Commission can rely on Mr. Rose's probability-weighted forecast of capacity prices as appropriate and reasonable.

d. **The cost projections provided by Company witness Lisowski are appropriate and reliable.**

No intervenor witness has offered their own dispatch analysis for the plants, or their own cost projections for the Plants for any given level of dispatch analysis. Despite their complete silence on this point, a few intervenors have criticized Mr. Lisowski's projections. Each of those criticisms lacks merit.

(i) The model used by Mr. Lisowski is the same sophisticated model typically used by FES.

Sierra Club has taken issue with the model used by Mr. Lisowski because it is run through Microsoft Excel and does not take into account the rest of the PJM system.[226] Those arguments significantly misunderstand the modeling done by the Companies' witnesses. Mr. Rose conducted a sophisticated analysis, relying on models which are highly complex and take into account a wide range of variables.[227] Those sophisticated models produced, among other

[225] *See* Company Ex. 20 (Rose Confidential Workpapers) at 1-2.

[226] Sierra Club, p. 39.

[227] Rose Direct, p. 2; Rose Rebuttal, pp. 3; 7. As OCC/NOPEC witness Wilson admitted at hearing, ICF's modeling software, IPM, provides forecasts of least cost capacity expansion, electric dispatch and emission control strategies

things, the hourly energy prices, capacity prices, and fuel prices sponsored by Mr. Rose.[228] Mr. Lisowski then used those inputs provided by Mr. Rose to calculate how often the Plants would dispatch, and the costs associated with that dispatch. In fact, there is no need for Mr. Lisowski to use a modeling system that simulates the entire Eastern Interconnect; Mr. Rose has already done that.

Sierra Club also takes issue with the fact that the model is not commercially available.[229] The model used by Mr. Lisowski is a proprietary model owned by FirstEnergy Service Company, which regularly updates it.[230] FES relies on this model regularly in making business and capital investment decisions.[231] Because FES regularly used it to forecast the long-term dispatch of its plants for any given set of inputs, there is no reason to believe that the proprietary model is inaccurate. If Sierra Club had truly been concerned that Mr. Lisowski's model run were inaccurate it could have run Mr. Rose's inputs through one of the commercially available models it discusses in its brief.[232] Sierra Club did not do so (nor did any other intervenor). The failure to provide such evidence casts doubt on any question of the validity of Mr. Lisowski's model.

Sierra Club suggested that the Companies should have run a sensitivity analysis on Mr. Lisowski's model run.[233] This argument shows a lack of understanding of what Mr. Rose and Mr. Lisowski did. Mr. Rose was responsible for creating the relevant inputs for energy prices, among other things. Mr. Lisowski then evaluated whether Mr. Rose was an expert, ascertained

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while meeting energy demand and environmental transmission dispatch and reliability constraints. Hearing Tr. Vol. XXII, p. 4538 (Wilson Cross).

[228] Hearing Tr. Vol. VIII, pp 1569-70 (Lisowski Cross).

[229] Sierra Club Brief, pp. 40-41.

[230] Hearing Tr. Vol. VIII, pp. 1562-65 (Lisowski Cross).

[231] Hearing Tr. Vol. VIII, p. 1583 (Lisowski Cross).

[232] Sierra Club Brief, p. 41.

[233] Sierra Club Brief, p. 41.

that he was, and accepted his inputs.[234] Based on those inputs, Mr. Lisowski then dispatched the units against that set of inputs.

> Q. Okay. But I'm asking about your dispatch model, not Mr. Rose's model. Okay? Did you perform a sensitivity analysis on your dispatch model?
>
> MR. ALEXANDER: Objection, asked and answered.
>
> EXAMINER PRICE: Overruled.
>
> A. No. I did not need to run a sensitivity analysis for two reasons. One, I was only provided one set of inputs to be used in the dispatch, so there's no way to even run another scenario, sensitivity, to your point.
>
> Third, I didn't believe it was necessary to run a sensitivity analysis additionally because of the reason that there was a sensitivity analysis through using probability basis of the inputs which are directly input into this dispatch model.[235]

As Mr. Lisowski explained, there is no need to run a sensitivity analysis when he was accepting the energy prices provided by Mr. Rose. As demonstrated above, Mr. Rose's analysis was probability weighted and made any sensitivity analysis superfluous, even if one could be done (which is not the case).

(ii) Modeling the Plants on an hourly basis would not substantively change the analysis.

Mr. Rose provided hourly prices to Mr. Lisowski, and those hourly prices were then averaged into nine hour types in each month.[236] The Plants were dispatched based on those nine hourly price averages. [237] Sierra Club argued that it is inappropriate to model in this manner and

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[234] Hearing Tr. Vol. VIII, p. 1632 (Lisowski Cross) (" Q. What did you do to evaluate whether he was an expert? A. I did a couple things. One is I looked at his background. I reviewed his resume. I reviewed all of the data that he provided in his testimony, his attachments and his workpapers. Looking at all of those, it was my opinion that he was an expert in his field.").

[235] Hearing Tr. Vol. VIII, p. 1636 (Lisowski Cross).

[236] Hearing Tr. Vol. VIII, p. 1580 (Lisowski Cross).

[237] Hearing Tr. Vol. VIII, pp. 1580, 1743 (Lisowski Cross).

claim the Companies should have conducted hourly dispatch analysis.[238] This criticism again shows a lack of understanding regarding modeling and forecasting. Simply put, because baseload units like the Plants have low variable costs and tend to dispatch often, hourly dispatching in the model is unnecessary. Mr. Moul explained this in his Rebuttal Testimony.

> Sammis and Davis-Besse are baseload plants with low variable costs that typically dispatch low in the supply stack. The proposed transaction will not change that. Sammis's variable costs range from [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIA**L], and Davis-Besse's range from [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in 2013 dollars, so low that Davis-Besse effectively runs like a must-run unit. In comparison, Company witness Rose's forecasted energy prices in ATSI range from [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] for the 2015-2031 period. Given the difference between Company witness Rose's projected energy prices and the projected levels of variable costs, it is clear that these Plants should economically dispatch low in the stack and are not expected to turn on and off hourly during the forecasted period.

In light of the low variable costs identified by Mr. Moul and the operating characteristics of a baseload plant, there was no need to dispatch the Plants hourly.

Moreover, the operational characteristics of coal and nuclear units make it impossible to ramp them up and down quickly in response to short-term market fluctuations. Instead, baseload plants like Sammis are managed on an integrated basis over multi-day periods.[239] At times, they are must-run units instead of being economically dispatched hour by hour.[240] Unlike peaking

[238] Sierra Club Brief, p. 40.

[239] Hearing Tr. Vol. XXXII, p. 6552 (Moul Cross).

[240] Hearing Tr. Vol. XXXII, pp. 6552-53 (Moul Cross).

units, the Plants are dispatched across multiple days and, therefore, hourly dispatch is not needed to forecast the Plants' revenues.[241]

(iii) The cost projections in the model are accurate.

Mr. Lisowski's model runs used cost projections provided by FES.[242] Some intervenors have challenged a small sub-set of those cost projections by arguing that FES may have understated projected environmental costs.[243] Importantly, no intervenor has even attempted to argue that the overall cost projections are not reasonable or, as testified to by Company witness Moul, "reasonably conservative."[244] Intervenors' criticisms fail to recognize the extensive and reliable forecasting process used to develop the cost forecasts. Mr. Lisowski testified that the cost projections at the Plants were made and kept in the regular course of business.[245] He also testified that there is a large team of individuals and engineers who are responsible for cost projections in their area of expertise:

> There's a large number of people at FES and within FirstEnergy generation that are involved with that. We discussed a little bit earlier things like the nuclear fuel. There's a whole entire organization within FirstEnergy Nuclear that's responsible for that. That's one example. There's a number of engineers, project managers, operators, analysts at the sites, at each of these plants that would be involved in this, and there's a lot of people in support organizations for FES and FES generation that would be providing input.[246]

Mr. Lisowski then explained that these individuals are evaluated based on the accuracy of their forecasts:

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[241] Moul Direct, p. 8-11 (discussing differences between baseload units like the Plants and peaking units without on-site fuel).

[242] Lisowski Direct, p. 3.

[243] Sierra Club Brief, pp. 43-44; ELPC Brief, pp. 34-36; OMAEG Brief, pp. 35-38.

[244] Moul Rebuttal, p. 4.

[245] Hearing Tr. Vol. VIII, p. 1613 (Lisowski Cross).

[246] Hearing Tr. Vol. VIII, p. 1613 (Lisowski cross).

> Their responsibilities, which they are reviewed against, quite frankly, for performance ratings each year are around the accuracy of these forecasts. So it's their responsibility to work directly with their site. If it is a fossil plant, the fossil leadership. If it's a nuclear plant, the nuclear leadership, to ensure that those cost projections are the most accurate and complete forecast that they can come up with.[247]

In his Rebuttal Testimony, Mr. Moul also refuted the argument that FES's projected costs were too low, pointing out that FES has experience with these costs and expected them to be accurate:

> Our cost forecasts are reasonably conservative. FES has operated the Plants for years and is confident, based on that experience, that these forecasts are conservatively high and are expected to cover all future costs. The actual costs of the Plants are expected to be similar to or lower than the forecasted costs, with environmental regulations not having a material effect.[248]

Mr. Moul also explained why the costs at the Plants were reliable. As Mr. Moul observed, "[w]e do not expect the costs of Sammis and Davis-Besse to be volatile over the next 15 years, which is why Rider RRS will work as a retail rate stabilization mechanism."[249] Mr. Moul then stated:

> The largest cost components at Davis-Besse are labor and depreciation, which are not subject to volatile swings. Davis-Besse's fuel costs are locked in through the Economic Stability Program period. The Davis-Besse forecast realistically represents what Davis-Besse's costs will actually be. Likewise, there is no reason to believe that the cost of the Sammis plant's largest cost component – fuel – will materially increase over the next 15 years, although the Companies' cost forecast conservatively assumes coal costs will increase. Indeed, while the Sammis plant's current average cost for medium sulfur Northern Appalachian coal is [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**], the Companies' forecast assumes medium sulfur Northern Appalachian coal prices start at [**BEGIN**

[247] Hearing Tr. Vol. VIII, p. 1614 (Lisowski cross).

[248] Moul Rebuttal, p. 4.

[249] Moul Rebuttal, p. 4.

> **CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. Moreover, the Companies' forecast includes Mr. Rose's carbon prices in the Sammis and OVEC fuel costs, which provides additional cushion in the cost forecast to account for regulatory risk that may never occur. So the Commission can rely on the Companies' cost forecasts as conservative.[250]

Accordingly, the Commission can rely on the cost projections provided by the Companies in this proceeding.

(iv) Environmental regulations have been properly quantified and accounted for by the Companies.

Various intervenors, led by the Sierra Club, raise the specter that Sammis or OVEC could incur more costs than the Companies project, in order to comply with possible additional future environmental regulations that may come into being during the Economic Stability Program. These additional compliance costs, they say, would be netted against market revenues under Rider RRS and reduce quantitative benefits for customers. However, Company witness Raymond L. Evans, Vice-President, Environmental and Technologies at FirstEnergy Service Company, explained at length how Sammis is compliant with existing environmental regulations, and is well-positioned to comply with pending environmental regulations, which are final and awaiting action by the state or FES at immaterial cost.[251]

Ultimately, intervenors made very few arguments against Sammis's environmental compliance in their initial briefs. In fact, Sierra Club's 126-page initial brief and ELPC's 61-page initial brief each spend only 2 ½ pages discussing Sammis's environmental compliance.[252] The briefs of OCC/NOAC and OMAEG make general arguments about plants fueled by coal,

[250] Moul Rebuttal, pp. 4-5.

[251] Companies' Initial Brief, p. 131-140; Evans Supp., p. 2.

[252] Sierra Club Brief, p. 43-45; ELPC Brief, p. 34-36.

but are devoid of any detail or any analysis specific to Sammis or the record in this case.[253] The intervenors generally rely on the testimony of Sierra Club witness Comings and OCC witness Ferrey, neither of whom did an analysis of Sammis's costs to comply with environmental regulations during the term of Rider RRS.[254] The handful of arguments the intervenors make specific to Sammis either overlook important facts about Sammis or significant pieces of Mr. Evans' testimony, or reflect a fundamental misunderstanding of environmental regulatory compliance.

a) Intervenor attacks on Sammis are based on a lack of understanding of Sammis's operations and environmental regulation.

Sierra Club does not – and cannot – assert that Sammis will be unable to comply with any specific existing or pending environmental regulation. Instead, Sierra Club contends that the Companies provided insufficient documentation to show their cost estimates fully account for environmental compliance costs Sammis is likely to face during the term of Rider RRS.[255] Notably, Sierra Club cites to no study or analysis to support its own opinions on environmental compliance costs Sammis is likely to face. Sierra Club further contends the Companies

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[253] See, e.g., OCC/NOAC Brief, p. 127 ("[C]ompliance with these pending regulations will undoubtedly significantly affect the future operation and economics of coal-fired generation, such as Sammis, because coal generation emits more of the regulated and targeted air emissions in these pending regulations than other widely used fossil fuels per MWh of power generated."); OMAEG Brief, p. 35 ("Although these future requirements are not designed specifically for coal-fired generation and the timing of the rules is unknown, compliance with the pending regulations will have a considerable impact on the operations of coal-fired generation."). Indeed, OCC/NOAC conclude, based on OCC witness Ferrey's testimony, that any environmental regulation could have an impact on Sammis, with no technical support or supporting detail. See OCC/NOAC Brief, p. 90 fn. 284. However, Mr. Ferrey was quite clear at hearing that his opinions do not relate to Sammis. For example, Mr. Ferrey has no basis for believing that the 2015 8-hour ozone standard will have any impact on Sammis. Hearing Tr. Vol. XXIII, pp. 4661, 4679 (Ferrey Cross). He has no basis for believing that the 1-hour SO_2 standard will have any impact on Sammis. Hearing Tr. Vol. XXIII, p. 4659 (Ferrey Cross). Also, Mr. Ferrey did not study the impact of CSAPR on Sammis and has no opinion on whether CSAPR will have any impact on Sammis. Hearing Tr. Vol. XXIII, p. 4657 (Ferrey Cross).

[254] Hearing Tr. Vol. XXXI, pp. 6413, 6450 (Comings Cross); Hearing Tr. Vol. XXIII, p. 4659 (Ferrey Cross); see also note 253, *supra*.

[255] Sierra Club Brief, p. 44.

produced insufficient specific cost estimates or compliance plans for "a series of pending or proposed environmental regulations" in response to Sierra Club discovery requests.[256] The fact that the Companies' documentation of Sammis's environmental cost estimates and compliance plans does not meet Sierra Club's expectations is not evidence of any deficiency in proof that Sammis is well-positioned to comply with pending environmental regulations.

Sierra Club and other intervenors fail to recognize this basic fact: that Sammis is equipped with state-of-the-art pollution control technology, and already complies with stringent standards set by a 2005 federal Consent Decree.[257] The federal Consent Decree's standards exceed the requirements of several existing and pending environmental guidelines. As a result, Sammis's compliance with the Consent Decree makes the preparation of separate plans for Sammis to comply with less stringent pending environmental regulations unnecessary. In fact, Sierra Club witness Comings was not even aware of the Consent Decree when he prepared his testimony, and OCC witness Ferrey never read it.[258] Even after learning of the Consent Decree, neither witness bothered to review it before taking the witness stand.[259] Because Sammis has had to meet stringent standards under its Consent Decree for over ten years, it is already positioned to comply with pending additional environmental regulations.

To the extent the Sierra Club complains the Companies failed to produce cost estimates or compliance plans for a series of "proposed" environmental regulations, Sierra Club's expectations are unrealistic. A proposed environmental regulation – *i.e.*, one that is not final – may undergo many significant changes prior to finalization. The unreasonableness of Sierra

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[256] Sierra Club Brief, p. 44.

[257] Company Ex. 135 [Administrative Notice Taken at Hearing Tr. Vol. XXXI,p. 6464].

[258] Hearing Tr. Vol. XXXI, pp. 6462-63 (Comings Cross); Hearing Tr. Vol. XXIII, p. 4637 (Ferrey Cross).

[259] Hearing Tr. Vol. XXXI, p. 6464 (Comings Cross); Hearing Tr. Vol. XXIII, p. 4638 (Ferrey Cross).

Club's position is illustrated by Sierra Club's attacks on Sammis's plan to comply with recently issued effluent limitation guidelines ("ELGs"). While Sierra Club's brief faults the Companies for not producing a study of ELG compliance and costs,[260] Mr. Evans explained at hearing that no study had been possible earlier in the proceeding because there was no final rule:

> Q. Mr. Evans, you were asked earlier whether you had produced a written evaluation of ELG compliance costs. Earlier in the proceeding you stated you had not. Why not?
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> A. At the time of my supplemental testimony and deposition, EPA had not completed the final rule. They were considering eight different proposals at that time, and we had not produced any documentation regarding compliance with that rule at that time. Since that time, beginning on September 30, we completed a plan of cost and schedule for the ELG rule in its entirety for the Sammis plant.[261]

By insisting that the Companies should have developed a plan for compliance with a proposed rule that could have been finalized in at least eight different forms, Sierra Club urges the Commission to adopt an unrealistic standard for environmental planning.

Sierra Club's unrealistic expectations for environmental regulatory planning, and its lack of familiarity with Sammis's environmental compliance, reflect the lack of experience of its primary witness, Mr. Comings. As noted, Mr. Comings, who has taken no courses in the electric industry or environmental law or regulation, and who began his training on-the-job when he joined Synapse only a little over four years ago,[262] purports to be an expert on environmental regulation and compliance for power plants. Yet Mr. Comings has never had any operating responsibility for a generating plant. He has never had responsibility for implementation or design of an environmental compliance program for a generating plant or for designing

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[260] Sierra Club Brief, p. 45.

[261] Hearing Tr. Vol. XXXIII, p. 6793 (Evans Rebuttal Redirect).

[262] Hearing Tr. Vol. XXXI, p. 6397 (Comings Cross).

equipment necessary for an environmental compliance program for a generating plant. In fact, Mr. Comings has never even been to a generating plant.[263] Mr. Comings' belief that it is possible to develop cost estimates for environmental regulations that have not even been proposed[264] is understandable given this lack of experience. Notwithstanding his high expectations of those responsible for operating power plants, Mr. Comings himself did no forecast of Sammis's cost to comply with environmental regulations over the term of Rider RRS.[265]

Given the intervenor witnesses' lack of awareness of the important fact that Sammis operates under a federal Consent Decree, and the lack of qualifications of Sierra Club's witness Mr. Comings in particular, Sierra Club has no legitimate basis to challenge Mr. Evans' expert opinion regarding Sammis's costs and plans for environmental compliance.

b) Sammis' cost to comply with the effluent limitation guidelines is immaterial.

ELPC contends that the Companies, at the time of the September hearing in this case, did not provide any capital cost estimate relating to compliance with effluent limitation guidelines ("ELGs") regulating wastewater discharges from coal plants.[266] However, ELPC's brief fails to account for Company witness Evans' Rebuttal Testimony filed October 20, 2015. Mr. Evans' Rebuttal Testimony explained that his supplemental testimony had addressed compliance with the proposed revisions to the ELGs to the full extent possible. As stated above, the U.S. EPA proposed eight different potential technology pathways for consideration and identified four of

[263] Hearing Tr. Vol. XXXI, pp. 6445-46 (Comings Cross). Further, the only part of the Clean Air Act Mr. Comings thought applies to coal-fired generating plants is 111(d), an incorrect view that neglects such things as the MATS rules, new source review rules, and the National Ambient Air Quality Standards also promulgated under the Clean Air Act. Hearing Tr. Vol. XXXI, pp. 6446-48 (Comings Cross).

[264] Hearing Tr. Vol. XXXI, p. 6450 (Comings Cross).

[265] Hearing Tr. Vol. XXXI, pp. 6413, 6450 (Comings Cross).

[266] ELPC Brief, p. 34-35.

those as potentially being preferred by the agency. Developing a plan to comply with a proposed rule that could have gone in any of eight different directions would not have been a reasonable use of resources.[267]

The ELGs were finalized on September 30, 2015, the day following Mr. Evans's first appearance on the witness stand. Later, in his Rebuttal Testimony and at hearing, Mr. Evans explained that Sammis is positioned to meet the new ELG requirements at minimal cost. Sammis has no ELG requirements regarding its fly ash disposal and, thus, no additional costs.[268] Also, ELG requirements related to bottom ash wastewater will result in only minimal modifications to the disposal process.[269] The estimated cost of these modifications is only $3-5 million, including the cost of lining the settling pond already under consideration pursuant to the CCR rule, which is discussed further below.[270] In addition, ELG requirements related to FGD wastewater can be addressed at minimal cost.[271] Mr. Evans testified that the treatment system required by the new ELG requirements for FGD wastewater will cost between $8 and $18 million dollars spread out over three to four years.[272] Accordingly, ELPC's argument that "the Companies did not provide any capital cost estimate relating to compliance with the pending rule"[273] is plainly incorrect.

Notably, Sierra Club has no alternative cost projections for compliance with the ELGs. Its witness Mr. Comings did none.[274] Instead, Sierra Club resorts to asserting that the Companies

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[267] Evans Rebuttal, pp. 1-2.

[268] Evans Rebuttal, p. 2.

[269] Evans Rebuttal, p. 2.

[270] Hearing Tr. Vol. XXXIII, p. 6794 (Evans Rebuttal Redirect).

[271] Evans Rebuttal, p. 2.

[272] Hearing Tr. Vol. XXXIII, p. 6788 (Evans Rebuttal Cross).

[273] ELPC Brief, pp. 34-35.

[274] Hearing Tr. Vol. XXXI, p. 6450 (Comings Cross).

have provided no basis or support for such cost estimates.[275] To the contrary, Mr. Evans provided exactly the support Sierra Club describes, through his Rebuttal Testimony and at hearing.[276] At hearing in October following the filing of his Rebuttal Testimony, Mr. Evans explained that once the ELGs were finalized on September 30, his environmental department prepared a compliance plan.[277] Sierra Club and other parties had ample opportunity to question Mr. Evans regarding that compliance plan at hearing.

Company witness Evans has fully explained that the ELGs will not cause Sammis's costs to exceed the Companies' projections. Mr. Lisowski's forecast, validated by Mr. Evans with Mr. Lisowski after Mr. Evans' deposition, includes capital dollars that are sufficient to cover the cost of implementing ELG improvements at Sammis.[278] Indeed, Mr. Lisowski's forecast for Sammis assumes a non-outage capital budget of [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] per year to cover such things as environmental projects.[279] Therefore, the ELGs will not have a material impact on the quantitative benefits of Rider RRS.

c) The CPP's hypothetical cost impact on Sammis is now irrelevant, as are intervenors' arguments relying on the CPP.

While the final CPP received much attention in testimony and at hearing, it is barely mentioned in intervenor initial briefs. In fact, Sierra Club's initial brief makes no mention of the CPP, while ELPC omits it from its discussion of costs of environmental compliance. This is

[275] Sierra Club Brief, p. 45.

[276] Evans Rebuttal, pp. 1-2; Hearing Tr. Vol. XXXIII, p. 6788 (Evans Cross).

[277] Hearing Tr. Vol. XXXIII, p. 6788 (Evans Rebuttal Cross).

[278] Hearing Tr. Vol. XIX, pp. 3786, 3806 (Evans Cross). See Hearing Tr. Vol. VIII, p. 1774 (Company witness Lisowski describing discussions with Mr. Evans to confirm cost forecast).

[279] Hearing Tr. Vol. VIII, pp. 1773, 1780 (Lisowski Cross). See also Company Ex. 25C, p. 8 (Lisowski workpapers showing total projected capital investment at Sammis of [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in years 2018-2024 when ELG improvements could be made.).

likely because of the U.S. Supreme Court's February 9, 2016 stay of implementation of the CPP pending resolution of legal challenges to the CPP.[280] Only NOPEC acknowledges the stay of the CPP's implementation.[281] Notwithstanding the stay, OCC/NOAC, NOPEC and OMAEG speculate that the CPP could reduce the Economic Stability Program's savings for customers.[282] However, given the likelihood that, with the stay in place, the CPP will not be in effect for the proposed eight-year term of Rider RRS, the intervenor's arguments about whether the Companies' forecast properly or sufficiently includes costs or impacts of the CPP are now besides the point. Indeed, the Companies' forecasts, having considered the CPP to have some impact, have likely overstated FES's costs for the eight-year term.

Even if the CPP had maintained its relevancy for Stipulated ESP IV's term, intervenors' reliance on it would still lack merit. OCC/NOAC and OMAEG reference the Commission's Comments to the U.S. EPA regarding the CPP, cautioning that changing from the current market-driven dispatch order to new environmentally-affected market dispatch would increase plant operating costs.[283] However, the Commission's Comments were not specific to Sammis, and neither OCC/NOAC nor OMA provide any basis to conclude the CPP would have any effect specifically on Sammis. With regard to Sammis, the Companies explained in their Initial Brief that U.S. EPA modeling of the rate-based approach to the CPP shows that the Plants will continue to provide relatively cost-effective generation, at high capacity factors, throughout the Economic Stability Program period.[284]

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[280] *See Chamber of Commerce v, EPA*, No. 15A787, Misc. Order (U.S. S. Ct. Feb. 9, 2016).

[281] NOPEC Brief, p. 41 n.139.

[282] NOPEC Brief, p. 41; OCC/NOAC Brief, p. 74-75; OMAEG Brief, p. 37-38.

[283] OCC/NOAC Brief, p. 74-75; OMAEG Brief, p. 37.

[284] Companies' Initial Brief, pp. 137-138 (citing Evans Errata, pp. 3-5).

OCC/NOAC further speculate that any decrease in plant operations due to pending environmental regulations could reduce revenues, while the same regulations increase plant costs.[285] Similarly, OMAEG speculates that even if the Companies' forecasted costs include the costs necessary for Sammis to comply with the CPP, the CPP could result in Sammis running less and receiving less revenues.[286] Again, neither OCC/NOAC nor OMAEG offers any actual evidence that this would be the case for Sammis. Contrary to their assertions, the record shows that any costs for Sammis to comply with the CPP is covered in Mr. Lisowski's cost forecast by unspecified capital dollars,[287] as well as Mr. Rose's projected carbon price.[288]

NOPEC, citing generally to Sierra Club witness Comings' Supplemental Testimony, argues the Companies have not established whether the Sammis generating units will perform under the CPP.[289] NOPEC's reliance on Mr. Comings' analysis of EPA modeling of the mass-based approach (instead of EPA's modeling of the rate-based approach analyzed by Company witness Evans) is misplaced for several reasons. First, and most importantly, Mr. Comings' presentation of EPA mass-based modeling shows no negative impact on Sammis during the eight-year Stipulated ESP IV period. In fact, during the years at issue for which data was available, all Sammis units are [**BEGIN CONFIDENTIAL**] [redacted]. [**END CONFIDENTIAL**] Second, doing a mass-based analysis requires numerous assumptions that were not in the EPA modeling of the mass-based

[285] OCC/NOAC Brief, p. 74-75.

[286] OMAEG Brief, p. 36-37. While OMAEG continually refers to the effects of the CPP on "the Plants," a term used in this case to include both Sammis and Davis-Besse, OMAEG presumably recognizes that the CPP is designed to regulate existing fossil-fuel generating plants, not the Davis-Besse nuclear plant.

[287] Hearing Tr. Vol. XIX, pp. 3699-3700 (Evans Cross).

[288] Hearing Tr. Vol. XIX, pp. 3822-23 (Evans Cross).

[289] NOPEC Brief, p. 41 (citing Sierra Club Ex. 73).

approach.[290] For example, the U.S. EPA's modeling of the mass-based approach does not include any trading across states, although the final rule enables states to achieve their mass goals with the flexibility of interstate trading. The omission of trading across states directly conflicts with the U.S. EPA's encouragement of states to use trading programs under either a rate-based or mass-based approach.[291] Additionally, EPA's modeling of the mass-based approach does not fully account for leakage, as required by the final rule.[292] Given this discrepancy between how states are likely to implement the mass-based approach and the EPA's modeling of the mass-based approach, constraints on generation at the state level illustrated in the modeling of the mass-based approach are not realistic. Although not directly relevant for purposes of Stipulated ESP IV, modeling of a more realistic mass-based approach that includes the trading allowed by the actual mass-based rule would provide a more accurate forecast of Sammis in years 2025 and 2030.

Moreover, Mr. Comings' analysis of EPA modeling of the mass-based approach was limited to the cases shown in Mr. Evans' workpapers that were used in the EPA's rate-based modeling.[293] For example, with respect to Sammis Unit 1, Mr. Comings reviewed only Case 5874 and Case 17649 in the mass-based modeling because these were the only two codes used in the rate-based modeling.[294] In addition to Case 5874 and Case 17649, there are seventeen other

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[290] Hearing Tr. Vol. XIX, p. 3770 (Evans Cross).

[291] SC Ex. 64, p. 3-10.

[292] SC Ex. 64, p. 3-45; Hearing Tr. Vol. XXXI, p. 6488 (Comings Cross).

[293] Hearing Tr. Vol. XXXI, p. 6497 (Comings Cross); *see* Comings Second Supp., p. 3 n.6 (referencing Evans workpaper as source of Sammis unit codes). A "case" is one instance of a unit, e.g., Case 5874 is Sammis Unit 1 as it exists today. Hearing Tr. Vol. XXXI, p. 6501 (Comings Cross) and Company Ex. 139. When a unit changes – by, for example, retrofitting to add pollution controls – the case identifier for the unit changes. Hearing Tr. Vol. XXXI p. 6496 (Comings Cross); *see* Company Ex. 140.

[294] Hearing Tr. Vol. XXXI, pp. 6498-99 (Comings Cross).

cases that the IPM model could use for Sammis Unit 1 alone.[295] Mr. Comings neglected to determine which of the other seventeen cases was the next case used by the IPM model – either a retirement case or a different operating scenario.[296] Instead, he assumed that if the IPM model stopped using these cases he found in Mr. Evans' workpapers, then a unit was retired. Thus, his testimony is not proof that [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in the mass-based modeling done by U.S. EPA.

Accordingly, the record evidence demonstrates that the Plants would be important parts of Ohio's plan for CPP compliance in the unlikely event the CPP becomes effective during the term of Stipulated ESP IV.

d) The 1-Hour SO2 National Ambient Air Quality Standard ("NAAQS") is not a concern for Sammis.

OMAEG incorrectly states that Sammis is in a nonattainment zone for the 1-hour SO_2 standard.[297] To the contrary, Sammis is in the northern part of Jefferson County, which is not designated nonattainment for the 1-hour SO_2 standard.[298] In addition, Ohio EPA has chosen not to model Sammis as part of the non-attainment area in southern Jefferson County because the plant is not viewed as impacting the non-attainment area.[299] In fact, Sierra Club witness Comings agreed that Sammis and the OVEC plants are not in nonattainment areas for the 1-hour SO_2 standard.[300]

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[295] Hearing Tr. Vol. XXXI, p. 6503 (Comings Cross) and Company Ex. 140.

[296] Hearing Tr. Vol. XXXI, pp. 6498-99 (Comings Cross) and Company Ex. 40.

[297] OMAEG Brief, p. 36 (citing OCC/NOAC Ex. 20 at 9-13; OMAEG Ex. 17 at 8).

[298] Hearing Tr. Vol. XXIII, p. 4653 (Ferrey Cross).

[299] Evans Supp., p. 6.

[300] Hearing Tr. Vol. XXXI, p. 6462 (Comings Cross).

Even if Sammis were located in a nonattainment area for the 1-hour SO_2 standard, it would not require any additional costs to comply with that standard. As a result of its federal Consent Decree, Sammis has the "latest state-of-the-art technology" that will satisfy the requirements of the 1-hour SO_2 standard.[301] Thus, the only compliance costs related to the 1-hour SO_2 standard are Sammis's ongoing scrubbing costs in accordance with good engineering practices.[302] At hearing, intervenor witnesses had no basis to disagree. Sierra Club witness Comings did no analysis of the potential costs of Sammis or the OVEC plants to comply with the SO_2 NAAQS.[303] Also, OCC witness Ferrey has no basis for believing that the 1-hour SO_2 standard will have any impact on Sammis.[304]

e) Sammis's costs to comply with solid waste regulations are immaterial and included in the Companies' cost forecast.

Sierra Club complains that FES's analysis of whether changes would be needed to Sammis's unlined bottom ash settling pond to comply with the pending coal combustion residuals ("CCR") rule will not be completed until 2017.[305] While FES continues to evaluate compliance with the CCR rule, any additional costs to comply are expected to be immaterial and are included in Mr. Lisowski's cost forecast.[306] Mr. Evans explained that FES is not forecasting any additional wastewater costs related to the bottom ash settling pond.[307] If remedial action is required, the cost of lining the settling pond is less than $1 million.[308] Further, this cost is

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[301] Hearing Tr. Vol. XIX, p. 3807 (Evans Cross).

[302] Evans Supp., pp. 6-7; Hearing Tr. Vol. XIX, p. 3824 (Evans Cross).

[303] Hearing Tr. Vol. XXXI, p. 6450 (Comings Cross).

[304] Hearing Tr. Vol. XXIII, p. 4659 (Ferrey Cross).

[305] Sierra Club Brief, p. 45.

[306] Evans Supp., p. 5.

[307] Hearing Tr. Vol. XIX, pp. 3800-01 (Evans Cross).

[308] Hearing Tr. Vol. XX, p. 3859 (Evans Cross).

included in the estimated cost of $3-5 million for modifications to the bottom ash wastewater disposal process to comply with the ELGs.[309] Therefore, Sammis's compliance with the CCR rule will not affect Rider RRS's benefits to customers.

f) OVEC environmental compliance does not have a material impact on costs to be included in Rider RRS.

ELPC argues that Company witness Evans failed to address potential costs of compliance for the OVEC plants under a 2014 U.S. EPA proposal to lower the national ozone standard from 75 parts per billion ("ppb") to 65-70 ppb.[310] As an initial matter, U.S. EPA did not reduce the national ozone standard to 65 ppb. On October 1, 2015, U.S. EPA revised the standard for ground-level ozone to 70 ppb.[311] The new ozone standard of 70 ppb should not present compliance costs for the OVEC plants because EPA is projecting that the areas around both plants will be in compliance with the new ozone standard based solely on existing ozone programs.[312] Also, Mr. Lisowski's cost forecast would have included compliance costs for the Cross-State Air Pollution Rule ("CSAPR"), which affects ground-level ozone, that OVEC would have provided him with respect to his testimony.[313]

Even if OVEC were required to incur some additional cost to meet ozone standards, FES is responsible for only 4.85% of the OVEC costs, and the OVEC costs are projected to be less than [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] of the total costs of the contract price.[314] Thus, any OVEC compliance costs should not materially affect the

[309] Evans Rebuttal, p. 5.

[310] ELPC Brief, p. 35.

[311] Evans Rebuttal, p. 3.

[312] See Company Ex. 136 (showing all Indiana and Ohio counties in attainment with the 70 ppb standard in 2025).

[313] Hearing Tr. Vol. XIX, p. 3820 (Evans Cross).

[314] Strah Direct, p. 7; Lisowski Direct, Attachments 1-3 (comparing total costs and return of Sammis and Davis-Besse to total costs of OVEC).

Companies' forecast. Indeed, even Sierra Club witness Comings could imagine only one potential environmental compliance cost related to the OVEC plants, and 4.85% of that capital investment, if ever made, would total only $3.3 million.[315] Only the portion of this cost amortized during the term of the PPA would be passed through to the Companies by FES.[316]

Therefore, to the extent the OVEC plants must incur any additional costs for environmental compliance, FES's 4.85% share of any such costs is immaterial to the quantitative benefits of the Economic Stability Program. Accordingly, ELPC's argument that environmental costs at OVEC may drive up costs of Rider RRS are baseless and should be rejected.

(v) The Capacity Performance requirements have increased projected plant revenues and was addressed by Mr. Lisowski at hearing.

Some intervenors have argued that the CP requirements improperly increase risk to customers and are understated in Mr. Lisowski's projections.[317] Those intervenors focus on the potential costs of the CP requirements, and ignore the potential benefits of the CP requirements for customers. Those intervenors also ignore the quantification of benefits of the CP requirements identified in both Exelon's brief and in Mr. Lisowski's hearing testimony.

Company witness Rose testified about the significant problems in the PJM market and its lack of appropriate compensation for baseload assets like the Plants.[318] Mr. Rose explained that the CP Order would actually operate to raise revenues to the Plants, constituting a significant benefit to customers.[319] The intervenors ignore the benefits identified by Mr. Rose. Instead, they

[315] Comings Direct, pp. 41-42.

[316] Comings Direct, p. 42.

[317] Sierra Club Brief, p. 66; PJM Brief, p. 8; IMM Brief, p. 4; EPSA/P3 Brief, pp. 10-12; Exelon Brief, p. 40; RESA Brief, p. 26.

[318] Rose Supp., pp. 24-27.

[319] Rose Supp., pp. 24-27.

focus only on the risk of penalties if the Plants are not able to perform on the designated dates. While the intervenors are correct that the Plants are at risk if they do not perform, they ignore that the Plants will be compensated more for performing on those dates.

The error in the intervenor positions can be seen in the Exelon and Dynegy briefs. Exelon correctly points out that the CP requirements will increase plant revenue.[320] "The amount of revenue for clearing as capacity performance units can be significant."[321] Exelon then admits that the "plants had cleared as capacity performance units, providing significant revenue for delivery years 2016/2017, 2017/2018 and 2018/2020 [sic]."[322] Dynegy also addressed this point in its brief, pointing out that the CP product would substantially increase revenue for the Plants.[323]

Mr. Lisowski sponsored the revenue projections for the Plants in his testimony. In his Direct testimony, Mr. Lisowski included projections of the capacity revenue for the Plants. At hearing Mr. Lisowski explained that those projections **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** the projected capacity revenues. There were two primary reasons for this difference. First, as pointed out by Exelon, PJM conducted transitional auctions for the 16/17 and 17/18 planning years after Mr. Lisowski filed his testimony. In those auctions **[BEGIN CONFIDENTIAL]** [redacted].[324] **[END CONFIDENTIAL]** Second, those transitional auctions had substantially higher clearing prices than the initial

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[320] Exelon Brief, p. 48.

[321] Exelon Brief, p. 48.

[322] Exelon Brief, p. 48.

[323] Dynegy Brief, p. 9.

[324] Hearing Tr. Vol. X, pp. 2135-46 (Lisowski Redirect).

auctions for those years.[325] Higher capacity prices lead to increased revenue for the Plants over and above that initially projected by Mr. Lisowski.

While the Companies were not permitted to provide the most detailed actual clearing price information at hearing,[326] Mr. Lisowski was permitted to testify that the Plants had cleared in the transitional auctions and to provide the clearing prices for those auctions.[327] Based on Mr. Lisowski's testimony and the exhibits filed at hearing, the table below shows the approximate impact of those transitional auctions based on the total MW for each Plant and compares that impact to that previously projected by the Companies.

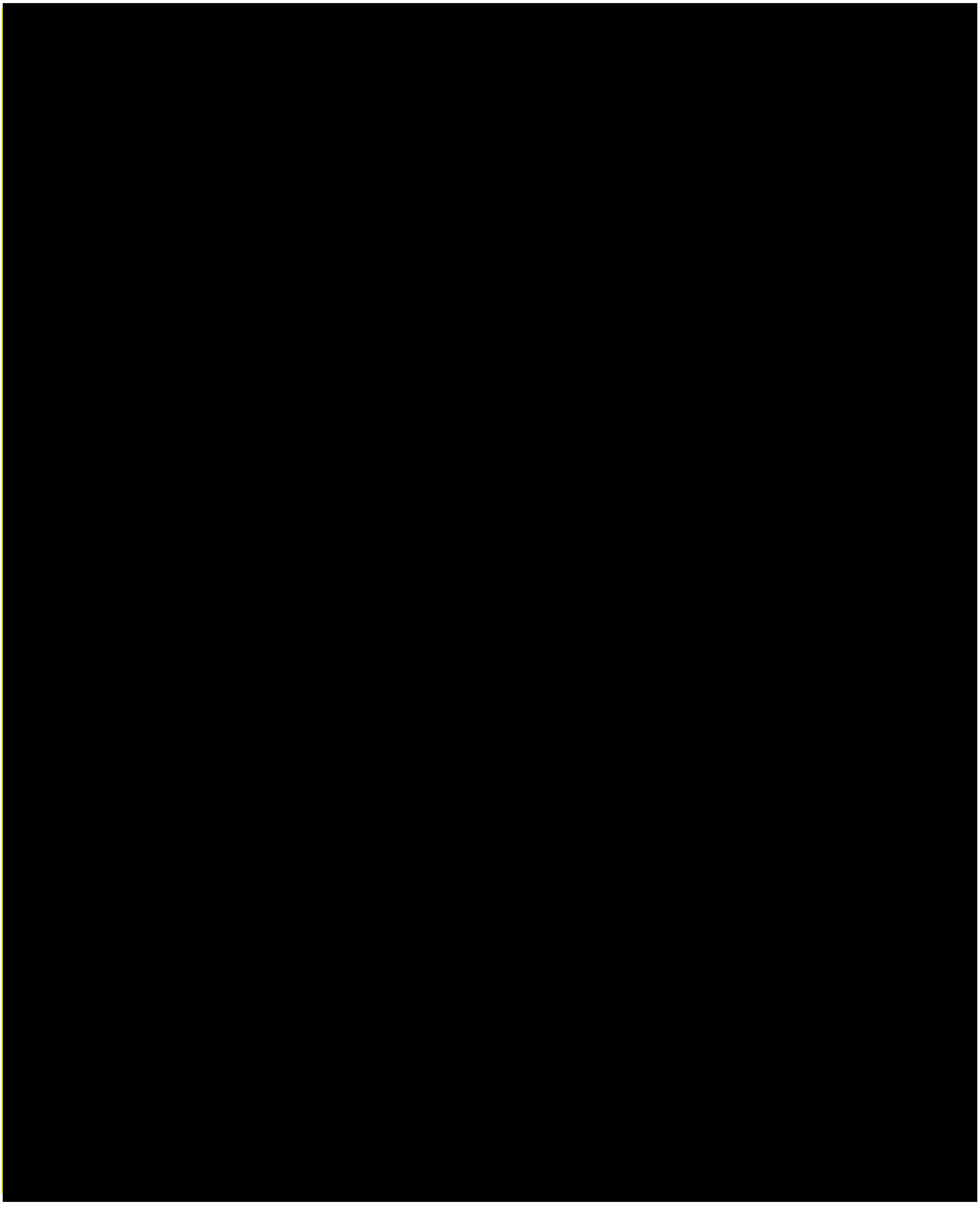
[**BEGIN CONFIDENTIAL**]

[325] Hearing Tr. Vol. X, pp. 2135-46 (Lisowski Redirect).

[326] *See* Hearing Tr. Vol. X, pp. 2129-34 (Lisowski Redirect) (sustaining objection to Companies Ex. 26(C), the exhibit which provided the exact amount of MW at each unit which cleared).

[327] Hearing Tr. Vol. X, pp. 2135-46 (Lisowski Redirect).

Figure 5



[**END CONFIDENTIAL**][328] As shown by this table, the CP product will increase the revenue at Davis-Besse, Sammis, and the OVEC entitlement by approximately [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] over that previously forecast by the Companies. This shows that rather than being a net cost, the CP requirements provide a substantial benefit to customers.

Interestingly, Dynegy is one of the intervenors who have claimed the CP requirements increase costs to customers.[329] However, on cross examination, its witness Ellis admitted that Dynegy did not act in a manner which suggested that risk was particularly significant. Instead, Mr. Ellis admitted that Dynegy had publicly commented in favor of the CP rules.[330] He also admitted that Dynegy had bid its generation into the PJM market as CP product.[331] In the 16/17 transition auction Dynegy cleared 6,542 MW as CP product and imported 730 MW into PJM from MISO territory in Illinois as CP product, which had the combined effect of increasing Dynegy revenue by $176 million.[332] In the 17/18 transition auction Dynegy cleared 6,508 MW as CP product and imported 471 MW into PJM from MISO territory in Illinois as CP product, which had the combined effect of increasing Dynegy revenue by $75 million.[333] For the 18/19

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[328] This table combines information from multiple sources. The information from Mr. Lisowski's workpapers was admitted through Company Ex. 25. The CP clearing price for each year is established through both Mr. Lisowski's testimony and Company Ex. 182 and 183. Mr. Lisowski was permitted to testify that FES had publicly announced the Plants had cleared in the auction. Hearing Tr. Vol. X, pp. 2140-45 (Lisowski Redirect). The specific amount of MW which cleared for Sammis was provided at Hearing Tr. Vol. X, pp. 2157-58 (Lisowski Recross). The only figures on the chart not specifically discussed in the record are the specific number of MW/year which cleared for Davis Besse and OVEC. Therefore this representative chart uses UCAP MW for Davis Besse and OVEC for each year to provide an approximate example showing the impact the CP product had on the Plants. This is appropriate since Mr. Lisowski testified Davis Besse and OVEC cleared in those years.

[329] Dynegy Brief, pp. 13, 19.

[330] Hearing Tr. Vol. XL, p. 8535 (Ellis Cross).

[331] Hearing Tr. Vol. XL, p. 8536 (Ellis Cross).

[332] Hearing Tr. Vol. XL, pp. 8537-39 (Ellis Cross).

[333] Hearing Tr. Vol. XL, pp. 8539-42 (Ellis Cross).

BRA auction, Dynegy cleared 9,891 MW as CP product.[334] For each of these auctions Dynegy had previously cleared some or all of the units as base capacity product and made the strategic decision to convert to CP product in order to increase revenues.[335] This also had the effect of exposing Dynegy to the risks associated with the CP product.[336] Given that Dynegy has chosen to expose itself to the risks associated with the CP requirements in order to get the increased revenues associated with the CP product, its claim the CP requirements improperly increase risks to customers rings hollow.

(vi) Mr. Lisowski appropriately forecasted plant revenues

Sierra Club argues that Mr. Lisowski's projected revenues are overstated because Mr. Lisowski used capacity factors which are higher than historical capacity factors.[337] Relying on Dr. Kalt and Mr. Comings, Sierra Club argues that this means that plant revenue will be lower than projected by Mr. Lisowski.[338] This is wrong because the calculations made by these witnesses are wrong. Both Dr. Kalt and Mr. Comings assume that lower capacity factors will have an impact on revenues, but neither make any adjustment to costs to adjust for the lower capacity factor.[339] In short, if the Plants are running less often, they would incur less variable costs, such as fuel costs.

Sierra Club also claims that Mr. Lisowski's capacity revenues are overstated because he projects 400 more MW of capacity are sold than actually have cleared to date in the 18/19

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[334] Hearing Tr. Vol. XL, p. 8542 (Ellis Cross).

[335] Hearing Tr. Vol. XL, pp. 8542-43 (Ellis Cross).

[336] Hearing Tr. Vol. XL, p. 8543 (Ellis Cross).

[337] Sierra Club Brief, p. 30.

[338] Sierra Club Brief, p. 30.

[339] Comings Third Supp., pp. 12-14; Kalt Second Supp., pp. 21-22, Attachment JPK-SS-5.

BRA.[340] Sierra Club's analysis fails to understand the PJM capacity market. As Mr. Rose explained at hearing, all capacity is not required to be sold at the time of the BRA. That capacity can be bid into future incremental auctions, sold bilaterally, or be kept in reserve.[341] This was also explained by Mr. Lisowski with regard specifically to the 18/19 year. [**BEGIN CONFIDENTIAL**]

[redacted]

[redacted]

[redacted]

[**END CONFIDENTIAL**].[342] The unsold capacity is still available for sale and any revenue from the sale of that capacity will go to customers. This is simply prudent bidding behavior, not an overstatement of revenues. Accordingly, Mr. Lisowski's forecasts of capacity revenues for the 18/19 planning year are still valid.

2. The Intervenors' projections regarding the impact of Rider RRS are unreliable.

a. None of the Intervenors' witnesses have any experience in forecasting comparable to Mr. Rose's experience.

Several parties argue that the Companies' forecast must be wrong because it alone shows that Rider RRS provides a net credit to customers. This is not only wrong, but it assumes that all

[340] Sierra Club Brief, pp. 33-34.

[341] Hearing Tr. Vol. VII, p. 1383-85 (Rose Cross).

[342] Hearing Tr. Vol. IX, p. 1986 (Lisowski Cross).

projections provided here are worthy of equal weight and that all who provided said projections are equally qualified. On this latter point, the record demonstrates that compared to Company witness Rose, OCC/NOPEC witness Wilson, EPSA/P3 witness Kalt and Sierra Club witness Comings have little, if any, experience forecasting energy, capacity or carbon prices.

Mr. Rose has a degree in economics from the Massachusetts Institute of Technology and a Master's Degree in Public Policy from the John F. Kennedy School of Government at Harvard University.[343] Mr. Rose is a Managing Director and co-chair of ICF's Energy Advisory and Solutions Practice.[344] ICF has been the principal power consultant to the U.S. EPA for over 40 years.[345] ICF has also worked with FERC, the U.S. DOE, numerous state regulators, energy agencies, United States and Canadian utilities, and regional transmission organizations.[346] Mr. Rose has also served as a member of ICF's Board of Directors and is one of only three individuals, out of 5,000 professionals at ICF, to have received ICF's honorary title of Distinguished Consultant.[347] Mr. Rose has testified in over 120 proceedings before FERC and numerous state commissions, including, on several occasions, Ohio.[348] Mr. Rose has also made over 100 presentations at major energy conferences and published over a dozen articles in major trade and industry journals.[349] Further, Mr. Rose has more than thirty-two years of experience at ICF in making forecasts and projections relevant to the utility industry.[350] Thus, it cannot be disputed that Mr. Rose has "extensive experience…forecasting wholesale electricity prices,

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[343] Rose Direct, p. 1.

[344] Rose Direct, p. 1.

[345] Rose Direct, p. 2.

[346] Rose Direct, p. 2.

[347] Rose Direct, p. 1.

[348] *See* Rose Direct, Attachment 1, pp. 66-76.

[349] *See* Rose Direct, Attachment 1, pp. 76-85.

[350] Rose Direct, p. 1.

power plant operations and revenues, transmission flows, and fuel prices (e.g., coal, natural gas)."[351] In short, forecasting in the energy area is what Mr. Rose has done for many years, and he has been widely regarded as being one of the foremost experts in this area.

The qualifications and experience of Mr. Wilson, Dr. Kalt and Mr. Comings pale by comparison. In fact, as to forecasting, they are dilettantes. Mr. Wilson admitted that the little modeling or forecasting that he had done occurred early in his career.[352] Since then, he has only "evaluated" models and forecasts.[353] Hence, unlike Mr. Rose, who routinely engages in model-based forecasting, Mr. Wilson admitted that he does not generate such forecasts during the course of his work.[354] Indeed, he admitted that he had done no independent forecasts of any sort in this case, including independent forecasts of energy, capacity or natural gas prices.[355] Further, Mr. Wilson admitted that he had done no study or analysis related to the effect of plant additions or retirements in PJM on wholesale capacity prices or wholesale energy prices.[356]

Mr. Comings admitted that his education did not include courses in the electric industry, environmental law or regulation, contract law or any courses that "have the goal of forecasting."[357] Further, Mr. Comings admitted that the only training he had received in such areas was "on the job."[358] Mr. Comings also admitted that he had never been employed by a utility and that anything he knows about the PJM market was acquired through on-the-job-

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[351] Rose Direct, pp. 2-3.

[352] Hearing Tr. Vol. XXII, pp. 4541-42 (Wilson Cross).

[353] Hearing Tr. Vol. XXII, pp. 4541-42 (Wilson Cross).

[354] Hearing Tr. Vol. XXXVIII, p. 8116 (Wilson Cross).

[355] Hearing Tr. Vol. XXII, pp. 4541-42 (Wilson Cross). In contrast to ICF's broad and deep client base, Mr. Wilson further admitted that OCC was one of his top five clients and that OCC or organizations that included OCC accounted for as much as 35% of his billings. Hearing Tr. Vol. XXII, pp. 4500-02 (Wilson Cross).

[356] Hearing Tr. Vol. XXII, pp. 4542-43 (Wilson Cross).

[357] Hearing Tr. Vol. XXXI, p. 6397 (Comings Cross).

[358] Hearing Tr. Vol. XXXI, p. 6397 (Comings Cross).

training at Synapse,[359] where he has been employed for a mere four years.[360] Additionally, Mr. Comings admitted that prior to his work at Synapse, he had done no work involving the PJM market,[361] the Ohio energy market,[362] and no cost analyses of coal-fired generation plants.[363] Mr. Comings further admitted that he had done no analyses of energy prices (other than relating to certain types of so-called clean power) prior to joining Synapse.[364]

Mr. Comings also admitted that since joining Synapse he had never worked on behalf of a utility.[365] Moreover, Mr. Comings admitted that he has never had direct responsibility for forecasting capacity[366] or CO_2 prices[367] in PJM. As he admitted, Mr. Comings has only attempted to forecast energy and capacity prices in PJM in at most two prior cases[368] and in one of those cases the modeling was run by a colleague of Mr. Comings and not by Mr. Comings himself.[369] Mr. Comings readily admitted that Mr. Rose had "done many, many more of these types of forecasts."[370] Notably, Mr. Comings' experience is so weak and his testimony so discredited that no party even bothered to cite to any forecast that he did, with one exception. As discussed further below, that case, in which he used inputs from FES rather than Mr. Rose, is highly flawed.

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[359] Hearing Tr. Vol. XXXI, p. 6397 (Comings Cross).

[360] Hearing Tr. Vol. XXXI, p. 6397 (Comings Cross).

[361] Hearing Tr. Vol. XXXI, p. 6398 (Comings Cross).

[362] Hearing Tr. Vol. XXXI, p. 6398 (Comings Cross).

[363] Hearing Tr. Vol. XXXI, p. 6398 (Comings Cross).

[364] Hearing Tr. Vol. XXXI, p. 6398 (Comings Cross).

[365] Hearing Tr. Vol. XXXI, p. 6399 (Comings Cross).

[366] Hearing Tr. Vol. XXXI, p. 6402 (Comings Cross).

[367] Hearing Tr. Vol. XXXI, pp. 6402-03 (Comings Cross).

[368] Hearing Tr. Vol. XXXI, p. 6406 (Comings Cross).

[369] Hearing Tr. Vol. XXXI, p. 6404 (Comings Cross).

[370] Hearing Tr. Vol. XXXI, p. 6403 (Comings Cross).

Unlike Mr. Rose who has focused exclusively on the electric energy sector for the past thirty-two years, Dr. Kalt admitted that his publications over the last twenty years had been devoted to other things, like Native American issues.[371] Indeed, Dr. Kalt admitted that, in his prior ten years of experience, he could only identify three cases in which he provided testimony that ostensibly related to any projection of natural gas prices.[372] Regarding the first instance, a proceeding before the Public Utilities Commission of Colorado, Dr. Kalt admitted that there was nothing in his testimony that reflected natural gas price forecasts.[373] In the second case, a proceeding before the North Carolina Utilities Commission, Dr. Kalt admitted that he had only used NYMEX futures to reflect future natural gas prices.[374] He further admitted that, unlike what he did here, Dr. Kalt did not use any additional escalation factors based on the AEO Reference Case in that matter.[375] The third instance, an arbitration matter, involved the use of oil futures prices.[376] Dr. Kalt first contended that this was the only occasion when he allegedly conducted a quantitative analysis regarding the predictive value of future prices on what spot prices would be.[377] Yet, a review of the relevant portions of his testimony for this proceeding

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[371] Hearing Tr. Vol. XXVIII, p. 5608 (Kalt Cross).

[372] Hearing Tr. Vol. XLI, p. 8643 (Kalt Cross).

[373] Hearing Tr. Vol. XLI, p. 8646 (Kalt Cross).

[374] Hearing Tr. Vol. XLI, p. 8648 (Kalt Cross).

[375] Hearing Tr. Vol. XLI, p. 8649 (Kalt Cross).

[376] Hearing Tr. Vol. XLI, pp. 8665-66 (Kalt Cross) Dr. Kalt admitted that there were significant differences between the oil market and the natural gas market. Hearing Tr. Vol. XLI, p. 8653 (Kalt Cross). For example, Dr. Kalt admitted that the oil market was primarily international in nature, while the natural gas market is primarily confined to north America. *Id.* at 8653-8654. Dr. Kalt further admitted that oil was primarily used in the transportation sector (in the United States), while natural gas was primarily used for industrial, commercial, and residential boilers and power plants. *Id.* at 8654. Dr. Kalt also agreed that oil was characterized by major differences in oil quality while natural gas was relatively fungible. *Id.* at 8654-8655. Further, Dr. Kalt admitted while there may be market power issues with regards to oil due to, *e.g.*, OPEC the same market power issues were not a concern in the American natural gas market. *Id.* at 8655. Dr. Kalt also admitted that natural gas prices and oil prices do not necessarily move in the same direction. *Id.* at 8655.

[377] Hearing Tr. Vol. XLI, p. 8664 (Kalt Cross).

reveals no such analysis.[378] Hence, compared to the vast forecasting experience of Mr. Rose, over the past ten years Dr. Kalt has provided information on future prices in testimony on at most two occasions, both of which merely and exclusively reflected futures prices and one of which involved oil, not natural gas.

b. OCC/NOPEC witness Wilson's methodology was flawed, ad hoc and unreliable.

Numerous intervenors, including OCC/NOAC,[379] Sierra Club,[380] EPSA/P3[381] and NOPEC,[382] cite Mr. Wilson's claims that Rider RRS will result in significant charges to customers over the term of Stipulated ESP IV. OCC/NOAC claims that Mr. Wilson conducted an "independent analysis"[383] that purportedly generated "credible evidence"[384] to support his putative conclusions. Nothing could be further from the truth. As an initial matter, Mr. Wilson is hardly "independent". He admitted that OCC/NOAC had been a major client of his sole proprietorship consulting firm since 2008 or 2009.[385] Indeed, OCC/NOAC was among his top five clients,[386] representing a substantial part of his consulting revenues.[387] Since 2008, Mr. Wilson had submitted testimony on behalf of OCC/NOAC or groups including OCC/NOAC on ten occasions.[388] Further, as will be seen, Mr. Wilson's analyses were done specifically to

[378] *See* Hearing Tr. Vol. XLI p. 8663-8670 (Kalt Cross).

[379] *See* OCC/NOAC Brief, pp. 53-54, 71, 89, 109, 121-123, 133, 137 142, 163.

[380] *See* Sierra Club Brief, p. 13, 15.

[381] *See* EPSA/P3 Brief, pp. 3, 30, 33.

[382] *See* NOPEC Brief, pp. 5, 26, 30-32, 64, 73.

[383] OCC/NOAC Brief, p. 137.

[384] OCC/NOAC Brief, p. 133.

[385] Hearing Tr. Vol. XXII p. 4499 (Wilson Cross).

[386] Hearing Tr. Vol. XXII p. 4499 (Wilson Cross).

[387] Hearing Tr. Vol. XXII pp. 4500-4502 (Wilson Cross).

[388] Hearing Tr. Vol. XXII p. 4508 (Wilson Cross).

produce a desired result to produce a large cost number that OCC/NOAC and its allies in this case could trumpet to the public.

As noted, Mr. Wilson is hardly an expert in forecasts. He admitted that he does not "do" forecasts[389] and that he had done any computer modeling in this proceeding.[390] Indeed, Mr. Wilson admitted that he had done any independent forecasts of any sort in the present proceeding, including independent forecasts for energy,[391] capacity,[392] or natural gas prices.[393] Mr. Wilson also admitted that he did not do any modeling of the costs of the proposed transaction or potential revenues of the Companies.[394]

Mr. Wilson's methodology was deeply flawed and any reliance on his numbers is therefore misplaced. Instead of generating forecasts from a sophisticated and reliable model as Mr. Rose did, Mr. Wilson relied upon a few self-described "computer calculations" to arrive at his predetermined conclusions.[395] Simply put, Mr. Wilson's calculations hold everything constant from Mr. Rose's and Mr. Lisowski's forecasts except for natural gas prices.[396] He then came up with three "scenarios." Specifically, he replaced Mr. Rose's gas prices with those from: (1) the 2014 and 2015 EIA AEO Reference Cases (Mr. Wilson's Scenario No. 1); (2) the 2014 and 2015 EIA AEO High Oil and Gas Resource Cases (Mr. Wilson's Scenario No. 2); and (3)

[389] Hearing Tr. Vol. XXXVIII, p. 8116 (Wilson Cross).

[390] Hearing Tr. Vol. XXII, p. 4542 (Wilson Cross).

[391] Hearing Tr. Vol. XXII, p. 4542 (Wilson Cross).

[392] Hearing Tr. Vol. XXII, p. 4542 (Wilson Cross).

[393] Hearing Tr. Vol. XXII, p. 4542 (Wilson Cross).

[394] Hearing Tr. Vol. XXII, p. 4542 (Wilson Cross).

[395] Hearing Tr. Vol. XXII, p. 4542 (Wilson Cross).

[396] Wilson Direct, p. 44; Hearing Tr. Vol. XXII, pp. 4544-45 (Wilson Cross).

natural gas futures price accessed on December 4, 2014 and December 22, 2015 respectively (Mr. Wilson's Scenario 3).[397]

Aside from particular errors (as demonstrated below, there are many) that beset each scenario, Mr. Wilson made a fundamental methodological mistake that permeates his entire analysis. Although he replaced natural gas prices, Mr. Wilson did not change the implied heat rates used by Mr. Rose and Mr. Lisowski.[398] As Mr. Rose explained, "implied heat rates are the ratio of electrical energy prices in the marketplace to gas prices."[399] Mr. Wilson derived his energy price projections by multiplying his natural gas projections by the implied heat rates used by Mr. Rose.[400]

As Mr. Rose explains:

> Mr. Wilson erroneously holds each year's implied heat rates constant even as he changes the natural gas prices. In power modeling, it is standard practice to regard implied heat rates and electrical energy prices as being market modeling outcomes (*i.e.*, the dependent variables) with natural gas prices as an input or independent variable that impacts both the implied heat rate and the cost of gas generation. He violates this basic concept and practice by treating implied heat rates as a constant unaffected by large price changes to the underlying natural gas price stream. This will create significant understatements in his calculated electrical energy prices in markets with non-natural gas fired power plants setting marginal prices or when costs other than gas help set the price – *e.g.*, environmental allowances, non-fuel variable O&M. This is a fatal flaw to his overall methodology especially in Ohio with massive coal generation and given the newly finalized Clean Power Plan ("CPP") CO_2 regulations which cause a portion of the electrical energy price to reflect CO_2 allowance prices, not gas prices.[401]

[397] Hearing Tr. Vol. XXII, pp. 4544-45 (Wilson Cross); Hearing Tr. Vol. XXXVIII, pp. 8118-19 (Wilson Cross).

[398] Hearing Tr. Vol. XXXVIII, p. 4546 (Wilson Cross).

[399] Rose Rebuttal, p. 10.

[400] Hearing Tr. Vol. XXII, p. 4545 (Wilson Cross); Rose Rebuttal, p. 11.

[401] Rose Rebuttal, p. 11.

Mr. Rose provides the following example to illustrate the way in which Mr. Wilson's error leads to a significant understatement in energy prices:

> [Hypothetically] if the electrical energy price is set 50% of the time by coal generation which costs $50/MWh, and set 50% of the time set by gas generation at $50/MWh, with gas prices at $5/MMBtu delivered (and therefore gas plants have a heat rate of 10,000 Btu/kWh or $50MWh/$5/MMBtu), the electrical energy price is ($50/MWh+$50/MWh)/2 = $50/MWh. The implied system heat rate in this case is (50$/MWh) / $5/MMBtu = 10,000 Btu/KWh.[402] If the gas price falls in half, and nothing else changes, Mr. Wilson would calculate electrical energy prices as $2.5/MMBtu times 10,000 Btu/Kwh = $25/MWh. In fact, in this simplified example, the electrical energy price would be much higher. This is because the correct calculation is 0.5 times $50/MWh (the cost of coal generation) + 0.5 times 10,000 Btu/KWh times $2.5/MMBtu = $37.5/MWh. His error would be $25/MWh - $37.5/MWh or -$12.5/MWh. Thus, he would underestimate prices and revenues by a full one-third ($25/MWh/$37.5/MWh).[403]

Mr. Rose is not alone in his view that implied heat rates are not constant. Mr. Comings, for example, agreed that the ratio of energy prices to natural gas prices (*i.e.*, the implied heat rate) is not constant over time.[404] That implied heat rates change with natural gas prices cannot be seriously disputed. For example, as Mr. Rose testified at the hearing, "in most hours in Ohio today, coal plants are dispatching in competition with one another…[but in] about 20 to 25 percent of those hours, gas is the marginal source, so there is competition primarily among gas and coal and gas and gas."[405] In such cases where coal sets the margin, decreasing gas prices would have less of an effect on energy prices. Again, "[t]his will create significant

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[402] The calculation is as follows: "$50/MWh / $5/MMBtu = $50/MWh x MMBtu/$5 x 1000KWh/MWh x 1,000,000 Btu/MM = 10,000 Btu/Kwh." Rose Rebuttal, p. 11, n.10.

[403] Rose Rebuttal, pp. 11-12.

[404] Hearing Tr. Vol. XXXVIII, p. 8299 (Comings Cross).

[405] Hearing Tr. Vol. VI, p. 1151 (Rose Cross).

understatements in [Mr. Wilson's] calculated electrical energy prices in markets with non-natural gas fired power plants setting marginal prices."[406]

In light of these facts, Mr. Wilson should have been aware that the implied heat rate rises when natural gas prices are lowered (which occurred in all three of his scenarios) and adjusted his implied heat rate accordingly.[407] Mr. Wilson's intentional or negligent failure to do so amounts to a methodological flaw that undercuts his entire analysis and systematically and significantly understates electrical energy prices for each of his scenarios.

Beyond the above-described basic error, a review of each of Mr. Wilson's scenarios and his use of them reveals a consistent pattern of result-oriented calculation. Each of the scenarios is discussed in turn below.

<u>The 2014 and 2015 EIA AEO Reference Cases</u>: Mr. Wilson's first scenario uses the "Reference Cases".[408] Notably, Mr. Wilson claims that the projections from the 2014 and 2015 AEO "likely overstate natural gas and electric energy prices and revenues" (2014 Reference Case)[409] or are "out of date and out of line with market conditions" (2015 Reference Case).[410]

Yet, several key admissions on the part of Mr. Wilson regarding these cases prove telling. Mr. Wilson admitted that the 2014 Reference Case had one of the lowest projected Henry Hub prices for natural gas compared to other forecasts referred to by the AEO.[411] Even then, the results of the AEO Reference Case was not far from other forecasts. Of the four forecasts that the AEO compared itself to, the AEO natural gas price forecast was the second lowest through

[406] Rose Rebuttal, p. 11.

[407] Rose Rebuttal, p. 12.

[408] Wilson Direct, p. 11; Wilson Second Supp., p. 12.

[409] Wilson Direct, p. 45.

[410] Wilson Second Supp., p. 12.

[411] Hearing Tr. Vol. XXII, pp. 4547-4548 (Wilson Cross); 2014 EIA AEO (Company Ex. 60) at CP-12.

2025, but was the highest in 2035.[412] In fact, for that year, the difference between the AEO Reference Case and the ICF forecast available to the EIA was $.03/MMBtu (or less than 1%).[413]

Not surprisingly, the AEO Reference Case, based as it is on sound forecasting computer modeling, and having compared well to ICF's publicly available forecasts, compares well to Mr. Rose's forecast. As Mr. Rose testified at the hearing, "I am only 4 percent in real dollars higher than the EIA."[414]

Mr. Wilson also admitted that the 2014 Reference Case only took into consideration federal, state and local laws that were in effect as of the end of October 2013.[415] Therefore, as Mr. Wilson admitted, the 2014 Reference Case did not take into account the impact of PJM's CP rule, which, he agreed, would likely lead to higher capacity prices.[416] Thus, given its omission of any consideration for the CP rules, the AEO's Reference Case is likely low.[417]

Mr. Wilson's attempt to cast aside his Reference Case scenarios shows his bias. As Mr. Rose observes, "Because the EIA Reference Case is a reference case based on sound forecasting methodology, it is the most appropriate of the three cases."[418] Yet Mr. Wilson inexplicably dismisses the Reference Cases out of hand. Rather than choosing the methodologically sound alternative, Mr. Wilson arbitrarily views the EIA High Oil and Gas Resource Case and projections of natural gas prices based on natural gas futures as the more likely scenarios. The only explanation that Mr. Wilson attempts to provide to cast aside the Reference Case (at least

[412] Company Ex. 60 (2014 EIA AEO), p. CP-12.

[413] *Id.*

[414] Hearing Tr. Vol. XXXV, p. 7443 (Rose Redirect).

[415] Hearing Tr. Vol. XXII, p. 4549 (Wilson Cross).

[416] Hearing Tr. Vol. XXII, pp. 4550-51 (Wilson Cross). These admissions apply equally to the 2015 Reference Case as Mr. Wilson admitted that he used the same methodology in preparing his Second Supplemental Testimony as he had when he prepared his Direct Testimony. See Hearing Tr. Vol. XXXVIII, p. 8116 (Wilson Cross).

[417] Rose Rebutal, p. 39.

[418] Rose Rebuttal, p. 42.

initially for the 2014 AEO) was that the EIA had subsequently (in December 2014) published data showing an increase in natural gas reserves.[419] Mr. Wilson claimed that, had EIA "considered" that data in its April 2014 AEO, the forecasts would be lower.[420]

Yet, the 2015 AEO, which was published after the December 2014 gas reserves data (and thus which must have been data "considered" in developing the 2015 AEO) proved Mr. Wilson wrong. As demonstrated by Company Exhibit No. 65, after 2020, the 2015 Reference Case forecasts higher natural gas prices than the 2014 Reference Case, which Mr. Wilson admitted at hearing.[421] As Mr. Rose testified at the hearing, as of now, "the long-term average of [the] 2014 and 2015 [EIA Reference Cases] are within a percent of each other."[422]

Given that Mr. Wilson's initial explanation to reject the AEO Reference Case was proven wrong, there is only one conclusion to be drawn. Mr. Wilson rejected the only independent model that showed a possible RRS credit because it did not fit his significant client's case.[423]

<u>The 2014/2015 EIA High Oil and Gas Resource Cases</u>: As demonstrated at hearing, the reason Mr. Wilson chose to include the High Oil and Gas Resource Case was because it offered a better scenario for his position, i.e., to show that Mr. Rose's projection of natural gas prices was too high and to develop a large number for a cost for Rider RRS. As Mr. Rose explained, the High Oil and Gas Resource Case is one of twenty-one alternative scenarios to which the

[419] Wilson Direct, p. 30.

[420] Wilson Direct, p. 30.

[421] Hearing Tr. Vol. XXII, p. 4597 (Wilson Cross).

[422] Hearing Tr. Vol. XXXV, p. 7214 (Rose Cross).

[423] Mr. Wilson subsequently attempted to justify rejecting the AEO Reference Case on the basis that natural gas futures prices continued to fall. Hearing Tr. Vol. XXII, pp. 4587-90 (Wilson Redirect). As demonstrated below, however, futures prices are improper tools to forecast long-term natural gas prices, a fact of which Mr. Wilson is also well aware.

Reference Cases may be compared.[424] Conveniently for Mr. Wilson, it also just happens to be a case with forecasted natural gas prices that are significantly lower than the Reference Cases. As Mr. Rose noted, "EIA's 2014 High Oil and Gas Resource Case is 17.4% lower on average for 2015 to 2031 than the 2014 Reference Case."[425]

As Mr. Wilson admitted at hearing, of the five cases projecting natural gas prices in the 2014 EIA AEO, the High Oil and Gas Resource Case was the lowest case for "most years."[426] Indeed, Mr. Wilson agreed that "in most years, it's the lowest by a lot."[427] Mr. Wilson also admitted that the High Oil and Gas Resource Case assumes higher levels of oil and gas production.[428] He further admitted, upon reviewing the relevant portions of the 2014 AEO, that "there is uncertainty for sure, yes" regarding the projection of oil and gas production.[429]

At hearing, Mr. Wilson made a series of telling admissions to the Attorney Examiner; namely, that the 2015 High Oil and Gas Resource Case: (1) had the lowest projected prices for natural gas of any other forecast;[430] (2) through 2025 projected natural gas at less than $4.00 per MMBtu;[431] (3) had the next lowest prices for coal;[432] and (4) had the lowest of all electricity prices.[433] Mr. Wilson agreed with the Attorney Examiner that the 2015 High Oil and Gas

[424] Rose Rebuttal, pp. 47-48.

[425] Rose Rebuttal, pp. 45-46.

[426] Hearing Tr. Vol. XXII, p. 4552 (Wilson Cross).

[427] Hearing Tr. Vol. XXII, p. 4552 (Wilson Cross).

[428] Hearing Tr. Vol. XXII, p. 4552 (Wilson Cross).

[429] Hearing Tr. Vol. XXII, pp. 4553-55 (Wilson Cross). *See also* 2014 EIA AEO (Company Ex. 60) at MT-22.

[430] Hearing Tr. Vol. XXXVIII, pp. 8154-55 (Wilson Cross).

[431] Hearing Tr. Vol. XXXVIII, p. 8155 (Wilson Cross).

[432] Hearing Tr. Vol. XXXVIII, p. 8155 (Wilson Cross).

[433] Hearing Tr. Vol. XXXVIII, p. 8155 (Wilson Cross).

Resource Case was the "best case scenario… for customers if they want to pay the least, these are the lowest prices of natural gas, coal and electricity."[434]

Mr. Wilson admitted that the high oil and gas resources case involved certain assumptions such as: (1) "Estimated ultimate recovery per shale gas, tight gas, and tight oil gas is 50% higher and well spacing is 50% closer than in the Reference Case";[435] (2) "In addition, tight oil resources are added to reflect new plays of the expansion of known tight oil plays, and the EUR for tight oil and shale wells increases by 1% or more per year than the annual increase in the Reference case to reflect additional technology improvements";[436] and (3) "This case also includes kerogen development; undiscovered resources in the offshore Lower 48 states and Alaska; and coalbed methane and shale gas resources in Canada that are 50% higher than in the reference case."[437] Mr. Wilson admitted that he did not provide any evidence in his testimony regarding the validity of or support for *any* of those assumptions.[438] Again, only one conclusion can be drawn: Mr. Wilson simply mined the 2014 and 2015 EIA AEOs for the best scenario and then cherry-picked the High Oil and Gas Resource Case.

Natural Gas Futures: For his third scenario, Mr. Wilson relied on natural gas futures prices, ostensibly to predict natural gas prices for the entire term of Rider RRS. Mr. Wilson claims, based on this flawed analysis, that Rider RRS will result in a $3.6 billion charge to customers.[439]

[434] Hearing Tr. Vol. XXXVIII, p. 8156 (Wilson Cross).
[435] Hearing Tr. Vol. XXXVIII, p. 8157 (Wilson Cross).
[436] Hearing Tr. Vol. XXXVIII, p. 8158 (Wilson Cross).
[437] Hearing Tr. Vol. XXXVIII, p. 8158 (Wilson Cross).
[438] Hearing Tr. Vol. XXXVIII, p. 8158 (Wilson Cross).
[439] Wilson Second Supp, p. 7.

In a telling overstatement, OCC/NOAC describes the alleged $3.6 billion figure as a "best case scenario."[440] The record evidence puts such boasts to rest. As an initial matter, OCC/NOAC's hyperbole overlooks the fact that Mr. Wilson presented two other scenarios. While, as noted, each of these is flawed, they at least show a "better" case scenario for customers; indeed, the first scenario shows *credits for customers*.

In any event, regarding the methodology used by Mr. Wilson's third scenario, the record demonstrates that the use of futures to predict natural gas prices over the long term is methodologically flawed for at least two reasons: (1) because the futures market is extremely illiquid . . . i.e., represents very few actual transactions . . . beyond the first two or three years, relying on such prices in the "out years" is wholly unreliable; and (2) because the natural gas futures prices are highly correlative of spot prices and because natural gas prices are among the most volatile of any commodity, such prices are not predictive of which prices will, in fact be.

More specifically, gas futures are only useful for short-term forecasting due to the extreme illiquidity of the natural gas futures market after two years.[441] Figure 10 from Mr. Rose's Rebuttal Testimony, which shows the number of futures contracts in certain months,[442] dramatically illustrates the extreme illiquidity at issue:

[440] OCC/NOAC Brief, p. 163.

[441] Rose Rebuttal, p. 49.

[442] Rose Rebuttal, p. 50.

Figure 10

Number of Contracts Traded Per Month for Delivery

Year/Month	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
2014/1	8,589,210	304,250	9,468	2,144	523	5	101	1	1	0	0	0	0
2014/2	7,962,125	357,631	16,016	3,679	504	52	28	0	0	0	0	0	0
2014/3	4,420,592	361,252	15,714	5,367	1,427	15	0	0	0	0	0	0	0
2014/4	4,634,186	450,367	28,105	1,913	70	14	88	3	4	0	0	0	0
2014/5	4,435,529	581,758	15,760	1,144	63	4	5	1	0	0	0	0	0
2014/6	4,717,833	684,471	18,961	3,248	621	5	0	0	0	0	0	0	0
2014/7	4,134,106	867,650	28,287	2,326	952	1,801	0	0	0	0	0	0	0
2014/8	4,240,828	1,115,436	15,489	2,140	831	100	68	5	7	0	0	0	0
2014/9	4,003,345	1,584,166	39,749	3,184	389	1,536	1	0	0	1	0	0	0
2014/10	3,628,475	2,390,915	63,943	3,434	930	123	2	0	0	0	0	0	0
2014/11	2,783,881	5,125,644	84,174	1,393	65	30	8	0	0	1	0	0	0
2014/12	0	6,439,894	119,515	8,116	564	281	6	0	0	0	0	0	0
2015/1	0	7,416,074	226,666	6,095	191	7	6	0	0	0	1	0	0
2015/2	0	6,806,790	242,824	7,890	342	10	0	0	0	0	0	0	0
Total	**53,550,110**	**34,486,298**	**924,671**	**52,073**	**7,472**	**3,983**	**313**	**10**	**12**	**2**	**1**	**0**	**0**

Source: SNL Financial

Mr. Rose explained Figure 10:

> In the first two months of 2015, only 23 contracts were transacted for delivery in 2019 or beyond and only 1 was transacted past 2020. In contrast, from the same two months of 2015, approximately 14.7 million contracts traded for delivery in the first two years (i.e., 2015 and 2016). 14.2 million of the 14.7 million traded in the first year (i.e., 2015). The ratio of transactions in the first 2 years to transactions in years 5 and beyond is 14.7 million to 24, or 613,000 to 1, and as noted, there is only one transaction after year 6. Therefore, there is no evidence that the market conveys significant information about expectations of market participants for the 2017 to 2031 period, which is nearly the entire forecast period.[443]

Given such marked illiquidity, Mr. Rose observed: "I only use forwards for the first two years, and rely on the ICF fundamentals-based forecast of supply and demand for all other

[443] Rose Rebuttal, pp. 49-50. *See also* Figure 10, Rose Rebuttal, p. 50.

periods. I only rely on forwards in the near term because they are only liquid in the near term."[444]

Mr. Rose is not alone in this assessment. Mr. Wilson, for one, admitted at hearing that after three years, the volume of futures transactions becomes markedly lower: "The daily volumes are much lower for months out, for years out, yes."[445] At hearing, Mr. Wilson's fellow OCC/NOPEC witness Kahal, after explicitly admitting that Mr. Wilson's third scenario is based upon natural gas futures prices,[446] agreed that forecasts do not use future prices beyond the first two to three years because in the outer years the futures market is thin.[447] Likewise, RESA witness Scarpignato admitted that the NYMEX futures market is generally illiquid beyond three years.[448] So did Mr. Comings[449] and Dr. Kalt.[450]

A second basis for rejecting futures-based projections is that futures prices reflect spot market prices and are thus beholden to present conditions in the natural gas market. As Mr. Rose opined:

> Futures primarily reflect the spot market prices for natural gas at the time of issuance. This is because of the ability to store natural gas and arbitrage prices in the near term….futures natural gas prices follow spot prices….As discussed, there are practically no transactions for later years, but rather the futures price curve is based primarily on bid and ask quotations. The lower the spot prices, the lower the futures prices. In fact, there is an 81% correlation (put another way, the correlation coefficient is 0.81)

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[444] Rose Rebuttal, p. 49. The assertion that Mr. Rose relies on forward for terms longer than two years is baseless. As demonstrated by the record, the only time Mr. Rose has done so is at the direction of a client. *See* Hearing Tr. Vol. VII (CONF), p. 1437 (Rose Cross).

[445] Hearing Tr. Vol. XXII, p. 4567 (Wilson Cross).

[446] Hearing Tr. Vol. XXIV, pp. 4889-90 (Kahal Cross).

[447] Hearing Tr. Vol. XXIV, p. 4890 (Kahal Cross).

[448] Hearing Tr. Vol. XXIV, p. 5103 (Scarpignato Cross).

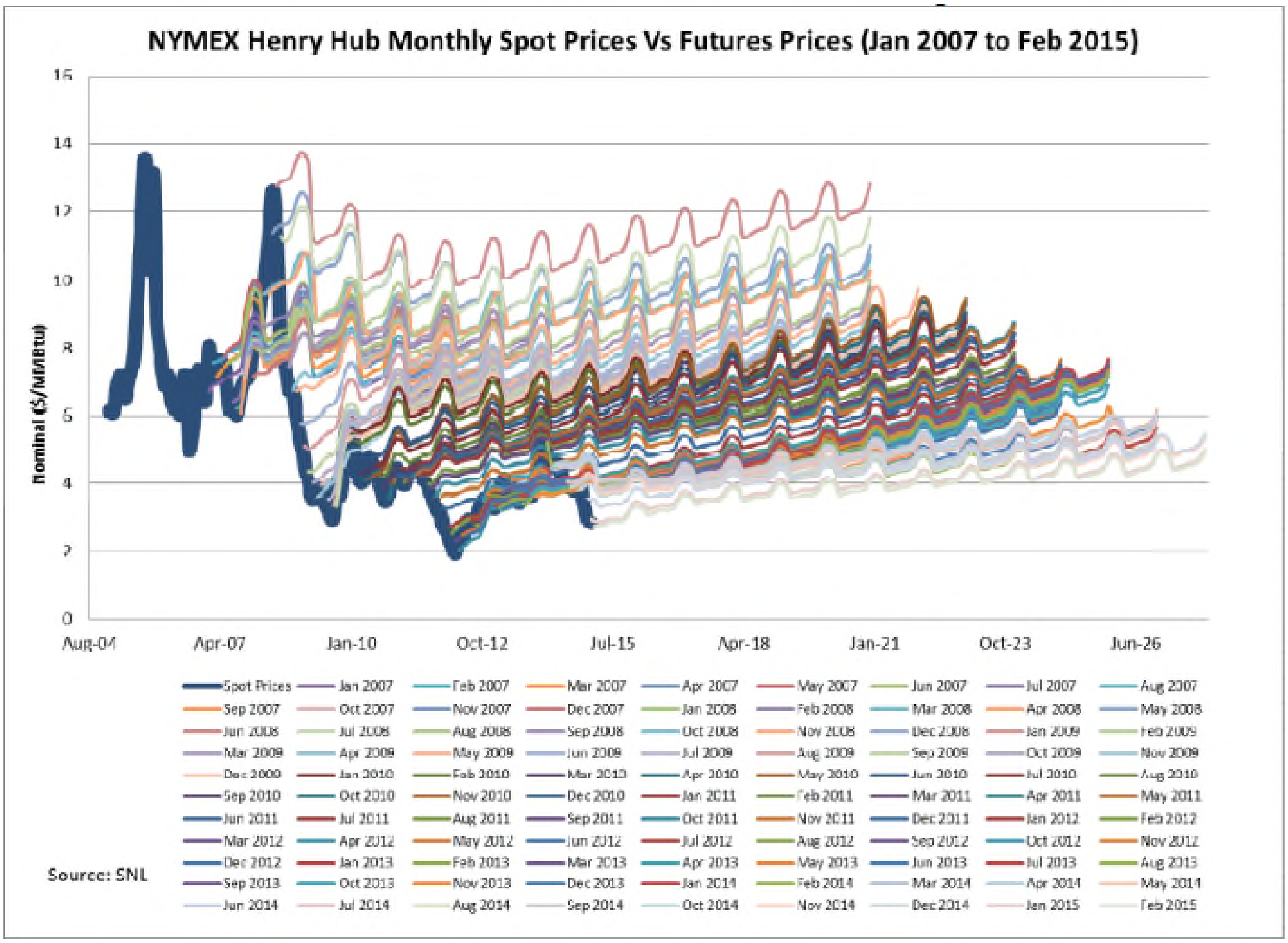
[449] Hearing Tr. Vol. XXXI, p. 6476 (Comings Cross).

[450] Hearing Tr. Vol. XLI, p. 8681 (Kalt Cross).

between the average futures price and the spot price on a monthly basis [from January 2007 to February 2015].[451]

Mr. Rose illustrated the above in Figure 11 from his Rebuttal Testimony:

Figure 11



As can be seen, natural gas futures closely track natural gas spot prices.

Notably, and problematically, Mr. Wilson bases his entire futures "calculations" on the prices at which natural gas futures were trading on a single market day, and extrapolates from there,[452] even though natural gas is a remarkably volatile commodity.[453] Thus, whatever market

[451] Rose Rebuttal, p. 51. *See also* Figure 11, Rose Rebuttal, p. 52.

[452] *See* Wilson Direct, p. 25 (relied on natural gas futures prices from December 5, 2014) and Wilson Second Supp., p. 11 (relied on natural gas futures prices from December 22, 2016). *See also* Rose Rebuttal, p. 49, n. 63.

conditions were in effect on those single trading days completely color Mr. Wilson's third scenario "calculations". Indeed, at hearing, Mr. Wilson admitted that December 2015 was the warmest December on record[454] and, as a consequence, natural gas storage was very full.[455] Mr. Wilson further admitted that in December 2015, the natural gas market was vulnerable, due to very weak demand conditions, to low prices.[456] Moreover, Mr. Wilson admitted that the low prices experienced in December 2015 should be considered *a very short-term condition.*[457] Hence, even Mr. Wilson apparently recognizes the inherent limits to using natural gas futures for long-term price predictions.

Mr. Wilson's methodologically flawed "calculations" and his arbitrary choice of his second and third scenarios in no way undermines Mr. Rose's forecasts. Mr. Wilson's failure to recognize the EIA Reference Cases, his cherry-picked use of the EIA High Oil and Gas Resource Cases, and his unjustifiable reliance on natural gas futures for long-term prognostications does nothing more than reflect his dilettante and biased approach to this entire proceeding. It is thus incredible that OCC/NOAC could claim that Mr. Wilson has presented "credible evidence" in this regard.[458] As the record demonstrates, Mr. Wilson's "calculations" simply cannot be taken seriously.

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[453] As Mr. Rose explained, "Indeed, of the most highly traded commodities on the NYMEX, including both energy and non-energy (including S&P 500, corn, coffee and gold), natural gas prices had the highest volatility on average from 2000 to 2015. The average natural gas price volatility was 57%, and the average of the eight other most highly traded commodities was 28.5%." Rose Rebuttal, p. 30.

[454] Hearing Tr. Vol. XXXVIII, p. 8119 (Wilson Cross).

[455] Hearing Tr. Vol. XXXVIII, p. 8119 (Wilson Cross). *See also* January 2016 EIA STEO (Company Ex. 167), p. 10 (discussing record inventory levels for natural gas).

[456] Hearing Tr. Vol. XXVIII, p. 8121 (Wilson Cross).

[457] Hearing Tr. Vol. XXVIII, p. 8121 (Wilson Cross).

[458] OCC/NOAC Brief, p. 133.

c. **EPSA/P3 witness Kalt's attempt to rely on futures pricing is similarly unreliable.**

Exelon argues that EPSA/P3 witness Kalt "explained why the Companies' projections were flawed" through his reliance on NYMEX futures.[459] Other parties also attempted to rely on Dr. Kalt's testimony.[460] But Dr. Kalt's natural gas projections thus are plagued by the same methodological flaws that beset Mr. Wilson. As an initial mater, Dr. Kalt admitted that he did not use a computer model to arrive at his conclusions regarding Mr. Rose's forecasted natural gas prices.[461] Instead, Dr. Kalt, like Mr. Wilson, relied on NYMEX futures ostensibly to show that Mr. Rose's long-term forecasts of natural gas prices are off the mark.[462] His attempt to do so leaves him open to all the objections already raised regarding the methodological flaws inherent in the use of futures to predict long-term natural gas prices.

At hearing, Dr. Kalt admitted that he provided no quantitative analysis to show whether natural gas futures are predictive of what spot prices would be,[463] while also admitting that natural gas prices are extremely volatile.[464] Moreover, Dr. Kalt admitted that after three years, the market for natural gas futures is "relatively thin" and the volume of trades go down.[465] He acknowledged that the thinness of the market beyond three years could result in a situation where a single transaction in that time period could significantly change the price for that futures period.[466]

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[459] Exelon Brief, p. 32.

[460] *See, e.g.,* Sierra Club Brief, p. 13; Dynegy Brief, p. 18; Cleveland Brief, p. 7.

[461] Hearing Tr. Vol. XLI, p. 8642 (Kalt Cross).

[462] *See* Kalt Second Supp. pp. 16-17 and p. 16, n. 30.

[463] Hearing Tr. Vol. XLI, p. 8661 (Kalt Cross).

[464] Hearing Tr. Vol. XLI, p. 8671 (Kalt Cross).

[465] Hearing Tr. Vol. XLI, pp. 8680, 8681 (Kalt Cross).

[466] Hearing Tr. Vol. XLI, p. 8681 (Kalt Cross).

Yet, Dr. Kalt opines that natural gas futures allegedly are a means to predict natural gas futures prices because “[t]hey arise from market participants of all kinds ‘putting their money where their mouths are’ by buying and selling futures contracts.”[467] Such a misguided claim reveals how out of his depth Dr. Kalt really is. As Mr. Rose explained, and other witnesses including Dr. Kalt agreed,[468] the futures markets are highly illiquid after two or three years. Indeed, as Figure 10 in Mr. Rose’s Rebuttal Testimony shows,[469] there are relatively few transactions beyond two years.

Mr. Kalt’s testimony provides one of the reasons for this pattern. As Dr. Kalt admitted, collateral requirements in futures transactions require buyers or sellers to cover the spread between a contract price and a price in a futures contract.[470] Dr. Kalt further admitted that the greater the length of such a contract, the more risk there is for a buyer or seller in having to meet such a spread.[471] Due to such increased risk, there will be markedly fewer transactions the further one moves away from current market conditions. Thus, contrary to Dr. Kalt’s claims, after the first few years, relatively few parties are actually “putting their money where their mouths are” in the natural gas futures market.

In a vain attempt to account for the thinness of NYMEX futures beyond two or three years, Dr. Kalt relied on them for the first three years of the term of Rider RRS and then followed the “trend” of 2015 EIA AEO Reference Case subsequent to 2018.[472] Dr. Kalt apparently believed that the EIA would have (and will) revise its 2015 AEO Reference Case

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[467] Kalt Second Supp. p. 14.

[468] Hearing Tr. Vol. XLI, pp. 8680-8681 (Kalt Cross).

[469] *See* p. 101, *supra*.

[470] Hearing Tr. Vol. XLI, pp. 8681-82 (Kalt Cross).

[471] Hearing Tr. Vol. XLI, p. 8682 (Kalt Cross).

[472] Kalt Second Supp., p. 17.

similarly to account for the decline in futures prices since the publication of the AEO in April of 2015. Dr. Kalt admitted at hearing, however, that he did no comparison of the 2015 Reference Case to the 2014 Reference Case regarding natural gas prices.[473] Certainly, as Mr. Wilson, Mr. Comings and Dr. Kalt are at pains to explain, natural gas futures prices declined from 2014 through 2015. For example, in his Direct Testimony filed in December 2014, Mr. Comings notes that NYMEX gas futures that he pulled on December 17, 2014 had gas futures at $3.58 for 2015 and $3.80 for 2016.[474] In his Supplemental Testimony filed in May 2015, Mr. Comings notes that NYMEX gas futures that he pulled on May 11, 2015 had gas futures at $3.01 for 2015 and $3.25 for 2016.[475] This represents an approximate 15% decrease in a mere four months. Thus, if Mr. Kalt's methodology had any validity, the 2015 AEO Reference Case would show a similar or greater decline from the 2014 AEO Reference Case. Not surprisingly, there is no such difference. Natural gas price projections in the 2015 Reference Case are only 1.5% lower than in the 2014 Reference Case.[476] Further, Dr. Kalt appears to be oblivious of the fact that "both EIA AEO reference cases (i.e., 2014 and 2015) are [**BEGIN CONFIDENTIAL**] [redacted]." [**END CONFIDENTIAL**][477]

Nor could Dr. Kalt point to any other testimony or source to validate or otherwise prove the accuracy of his methodology (much less it's acceptance or recognition by anyone other than him). In his grand total of three testimonies where he said that he gave projections for prices, he used only futures prices in two (and one of those was for oil prices, an entirely different commodity). Contrary to his claim, none of his testimony in any of those cases provided any

[473] Hearing Tr. Vol. XLI, p. 8678 (Kalt Cross).

[474] Comings Direct, p. 27.

[475] Comings Supp., p. 6.

[476] Rose Rebuttal, p. 45.

[477] Rose Rebuttal, p. 39.

analysis of the predictive value of futures prices.[478] In fact, comparing the futures data with actual spot prices discussed during his cross-examination showed how little value futures are as a predictor of prices.

In his testimony in the 2010 North Carolina case, Dr. Kalt used NYMEX natural gas futures data to project fuel prices for years 2012 through 2016.[479] He had a base case, as well as high gas price and low gas price sensitivity cases. For his base case in that matter, Dr. Kalt relied on then-existing NYMEX futures.[480] At hearing, Dr. Kalt agreed that at the time he presented the North Carolina testimony, gas futures prices for 2014 through 2016 were over $5.50 per MMBtu.[481] He also presented a high price gas sensitivity case assumed a price of $6.50 per MMBtu in 2012, increasing by 50 cents per MMBtu every year until 2016.[482] His low gas price sensitivity case held prices constant at $4 per MMBtu.[483] Dr. Kalt admitted that each of his cases, including his low case, predicted prices for 2015 that were higher than those prices actually turned out to be.[484] In fact, Dr. Kalt's gas price projections in all three cases were too high even in 2012, the very first year he projected. Henry Hub data for 2012 shows spot prices beginning at $2.67 per MMBtu in January and never rising above $3.54 per MMBtu for the rest of the year, well below Dr. Kalt's $4.00 per MMBtu low case.[485] That same data shows natural gas spot prices never breaking the $3.00 per MMBtu mark for most of 2015.[486]

[478] Hearing Tr, Vol. XLI, pp. 8644-8670 (Kalt Cross).

[479] Hearing Tr. Vol. XLI, pp. 8647-48, 8652 (Kalt Cross).

[480] Hearing Tr. Vol. XLI, p. 8649 (Kalt Cross).

[481] Hearing Tr. Vol. XLI, pp. 8651-52 (Kalt Cross).

[482] Hearing Tr. Vol. XLI, p. 8652 (Kalt Cross).

[483] Hearing Tr. Vol. XLI, p. 8652 (Kalt Cross).

[484] Hearing Tr. Vol. XLI, pp. 8652-53 (Kalt Cross).

[485] Sierra Club Ex. 11 (administratively noticed by the Attorney Examiner at Hearing Tr. Vol. VII, p. 1550).

[486] Sierra Club Ex. 11.

In the only other proceeding that Dr. Kalt could recall projecting prices, Dr. Kalt dealt with future oil prices, not future gas prices.[487] **[BEGIN EPSA/P3 CONFIDENTIAL]** [redacted] **[END EPSA/P3 CONFIDENTIAL]**. Data from the CME Group as of January 21, 2016 shows oil futures prices for February 2016 through January 2021 ranging from just $27 per barrel (February 2016) to $44 per barrel (February 2021).[492]

None of this should come as a surprise. As Mr. Rose's unrefuted testimony shows, natural gas future prices are highly correlative to spot prices. Indeed, like spot prices, futures prices are highly volatile. As noted, "there is an 81% correlation between the average futures price and the spot price on a monthly basis."[493] Thus, monthly futures prices will track spot price volatility 81% of the time, either going up or down accordingly. Thus, given the high volatility of natural gas spot prices, natural gas futures prices have been and should be expected to continue to be volatile as well.

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[487] Hearing Tr. Vol. XLI, p. 8653 (Kalt Cross).

[488] Hearing Tr. Vol. XLI (Confidential), pp. 8709, 8710-11 (Kalt Cross).

[489] Hearing Tr. Vol. XLI (Confidential), p. 8711 (Kalt Cross).

[490] Hearing Tr. Vol. XLI (Confidential), p. 8711 (Kalt Cross).

[491] Hearing Tr. Vol. XLI (Confidential), p. 8711 (Kalt Cross).

[492] Company Ex. 188 (administratively noticed by the Attorney Examiner at Hearing Tr. Vol. XLI, pp. 8657-58).

[493] Rose Rebuttal, p. 51. *See also* Rose Rebuttal Figure 11, *supra*, at p. 103.

Dr. Kalt's reliance on futures prices and his made up, ad hoc, unverified calculations should be seen for what they are: unreliable, junk testimony designed to serve as an unworthy and improper counterweight to the results of Mr. Rose's well recognized forecasting methodology. In this light, Dr. Kalt's testimony adds nothing worthwhile to these proceedings.

d. **Mr. Comings' calculations using FES inputs are not probative.**

Sierra Club trumpets Mr. Comings' testimony and calculations that were based on FES's inputs to FES's dispatch model.[494] Using the FES inputs, Mr. Comings claims that Rider RRS [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[495] Accordingly, Sierra Club claims that the Companies' forecast is wrong.[496] This argument falls flat for two reasons. Each of these reasons stems from the fact that FES in its projections was appropriately conservative: projecting costs that were likely too high and revenues that were likely too low. As it turns out, FES's numbers were overly conservative.

First, the FES inputs included a [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] carbon price than the forecast presented by the Companies. In fact, the carbon price contained in the FES projection is [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] of the Companies' forecast in years 2020-2024, and in one instance [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[497] Ironically, Mr. Comings criticized the Companies' estimate for carbon costs for being too low.[498]

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[494] Sierra Club Brief, p. 15. Note that Mr. Comings had previously compared two sets of inputs: (1) the Companies' inputs based largely on Mr. Rose's forecasts; and inputs used by FES in the normal course of its business for forecasting purposes. Comings Direct, p. 7. Although he initially attempted to claim that these two sets of inputs were inconsistent (Comings Direct, p. 6), he ultimately admitted that they were just different. Hearing Tr. Vol. XXXI, pp. at 6439-40 (Comings Cross).

[495] Sierra Club Brief, p. 13.

[496] *Id.*

[497] Comings Direct, Workpaper "FES Subpoena Response-Attachment 1 Sammis Revised-Competitively Sensitive Confidential-TC price comp."

[498] Comings Direct, p. 51.

A criticism that ended up being unambiguously incorrect. The United States Supreme Court's recent stay of the CPP implementation all but assures that there will be no price for carbon through the term of Rider RRS.[499] The recent stay has several consequences: (1) Mr. Comings' statement that carbon costs would be higher than those forecasted by the Companies is now proven to be completely false; (2) the carbon costs reflected in the FES projection now can be shown to be too high: and (3) the projected revenues from Rider RRS will significantly increase.

Sierra Club's argument is flawed, as can be seen from Mr. Comings' own workpapers. The approximate revenue impact of the higher FES carbon prices can be determined using the formula: revenue impact = carbon emission rate[500] * plant heat rate[501] * dispatch[502] * difference in carbon prices used by FES and the Companies.[503] Using this formula, the Rider RRS credit under the FES projection would [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] through the term of Rider RRS. The chart below shows the annual revenue difference between a projection using the Companies probability weighted carbon price and one using the FES carbon price.

[**BEGIN CONFIDENTIAL**]

[499] U.S. Supreme Court Order 15A793, 577 U.S. ___ (Feb. 9, 2016), available at http://www.supremecourt.gov/orders/courtorders/020916zr4_4g15.pdf.

[500] Comings Direct, Workpaper "Market Data FES Subpoena Response-Attachment 1 Sammis Revised-TC price comp."

[501] Comings Direct, Workpaper "Unit Data FES Subpoena Response-Attachment 1 Sammis Revised-TC price comp."

[502] Comings Direct, Workpaper "Sammis-Expense Synapse NPV calcs.

[503] Comings Direct, Workpaper "Market Data FES Subpoena Response-Attachment 1 Sammis Revised-TC price comp."

[redacted]

[**END CONFIDENTIAL**]

In addition to the positive effect related to eliminating the impact of FES's overly high projection for the price of carbon, Sierra Club conveniently overlooks the recent PJM Auction results for planning years 2016/2017, 2017/2018 and 2018/2019. These auctions will result in [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in additional revenue under Rider RRS, which further increases the benefit for customers.[504] Therefore, contrary to Sierra Club's claim, using FES's projections do not militate against Rider RRS. Recent events simply show that FES aggressively projected higher carbon prices and conservatively projected lower capacity prices. When taken together, Sierra Club's argument related to the FES projections unravels. In fact, the effect of these events on FES's projections reveals the exact opposite of what Sierra Club contends – Rider RRS should project a credit for customers.

[504] See Figure 5 above (Lisowski Table named "Actual PJM Auction Results Compared To Filed Workpaper")

3. Rider RRS and the proposed transaction are structured to benefit customers.

Given the Companies' forecast that Rider RRS will produce a $561 million retail rate stabilization benefit for customers, and given the lack of any probative, credible evidence to counter that forecast, the Commission has sufficient grounds to find that Rider RRS will benefit customers by providing them retail rate stability. As further discussed in the following sections, Rider RRS will function effectively as a counter-cyclical hedge – basically a form of insurance – against increasing and more volatile electric prices and provide long-term rate stability to customers.

a. Rider RRS is not an anticompetitive subsidy to FES.

Some intervenors, including Exelon, classify Rider RRS as an anticompetitive subsidy because it is supported by a market negotiated cost-based contract as compared to a contract based solely on market prices.[505] Coming from Exelon – whose affiliate Constellation sought approval from the New York Public Service Commission for a reliability support services agreement for Constellation's R.E. Ginna nuclear plant,[506] and which took the position that the Illinois General Assembly should enact legislation to create a low-carbon portfolio standard to ensure that the state avoided the negative consequences of closing nuclear facilities[507] – the argument that Rider RRS is an anticompetitive subsidy is hypocritical and barely worth mentioning. Moreover, these intervenors' objections focus on the PPA between the Companies and FES, which is not before the Commission for approval. What is before the Commission for approval is a retail rate stability rider that happens to be supported by a wholesale power agreement.

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[505] Exelon Brief, pp. 8, 10-12; EPSA/P3 Brief, pp. 3-5, 35-36; Dynegy Brief, p. 5; Cleveland Brief, pp. 6-7.

[506] Strah Direct, p. 16; Hearing Tr. Vol. XXVI at 5225-5233 (Campbell Cross).

[507] Hearing Tr. Vol. XXVI at 5213 (Campbell Cross).

To the extent intervenors believe FES will receive an anticompetitive subsidy because the Companies will pay FES a negotiated price based on cost elements for the energy, capacity, ancillary services and environmental attributes sold to the Companies,[508] intervenors are not correctly defining what a subsidy is. Market negotiated cost-based contracts are common and are used in a variety of scenarios.[509] Financial hedges are commonly used to provide price stability and manage risk.[510] Indeed, EPSA/P3 witness Kalt and other economics professors have extolled the virtues of long-term contracts as an effective hedge against market volatility.[511] Because market negotiated cost-based contracts are often used to mitigate the risk of changes in market prices, the nature of the contract is not evidence that Rider RRS is an anticompetitive subsidy.

Moreover, this claim is contradicted by recent Commission precedent. In Case No. 11-346-EL-SSO the Commission expressly rejected this theory, finding that cost-of-service contracts do not constitute a subsidy:

> in order for AEP-Ohio, and the newly created generation affiliate to continue to provide capacity consistent with its FRR obligations, we maintain our position that AEP-Ohio is entitled to its actual cost of capacity, which will in part, be collected through the RSR in order for AEP-Ohio to begin paying off its capacity deferral. As we previously established, parties cannot claim that AEP-Ohio's generation affiliate is receiving an improper subsidy when in fact, it is only receiving its actual cost of service.[512]

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[508] *See* Hearing Tr. Vol. I, pp. 32-33 (Mikkelsen Cross).

[509] *See* Hearing Tr. Vol. XXI, p. 4169 (Roberto Cross); Company Ex. 116, p. 6-9 (Brief of Colin C. Blaydon, Charles J. Cicchetti, Jeffrey A. Dubin, A.J. Goulding, William W. Hogan, Joseph P. Kalt, Paul R. Kleindorfer, Robert J. Michaels, Craig Pirrong, Vernon L. Smith, James L. Sweeney and Robert D. Willig as Amicus Curiae in Support of Petitioners, NRG Power Marketing v. Maine Pub. Util. Comm., U.S. Supreme Court Case No. 08-674 (July 14, 2009)); Hearing Tr. Vol. XXXI, p. 6421 (Comings Cross).

[510] Hearing Tr. Vol. XXVI, p. 5241 (Campbell Cross); Hearing Tr. Vol. XXVIII, pp. 5640-41 (Kalt Cross).

[511] Company Ex. 116, p. 6-7.

[512] Case No. 11-346-EL-SSO, Entry on Rehearing, pp. 26-27 (Jan. 30, 2013).

In light of this recent Commission authority, there can be no dispute that market negotiated cost-based contracts, even with affiliates and even accompanied by nonbypassable charges, are not subsidies.

Other intervenors claim that Rider RRS is a subsidy to FES because they believe it will be a net charge to customers rather than a credit.[513] However, if the Commission determines that Rider RRS will not result in a net charge to customers, then several intervenors admitted at hearing that Rider RRS would not be a subsidy. For example, OMAEG witness Hill was forced to admit that if the Commission believed the Companies' projections then Rider RRS would not be a subsidy:

> Q. Okay. So under the hypothetical that rider RRS is projected to have a $260 million net present value credit to customers at the beginning of year one, you would agree that rider RRS is not a subsidy, correct?
>
> A. Without making any statement about the plausibility of the hypothetical, I am trying to come up with a snotty answer, but I can't. That implausible hypothetical is correct.[514]

Dr. Hill was not alone in his belief. Other intervenor witnesses also admitted that if Rider RRS is projected to be a credit then Rider RRS would not be a subsidy. For example, OEC/EDF witness Roberto testified that payments which resulted in below market prices would not be a subsidy.[515] OCC/NOPEC witness Sioshansi also admitted that he would not consider Rider RRS to be a subsidy in any year in which it was a credit to customers.[516]

In truth, whether Rider RRS ultimately results in net credits to customers does not determine whether it generates a subsidy to FES. As Exelon witness Campbell observed,

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[513] *See* EPSA/P3 Brief, pp. 3-5; Cleveland Brief, pp. 6-7; IMM Brief, p. 6.

[514] Hearing Tr. Vol. XXXIX, p. 8362 (Hill Cross).

[515] Hearing Tr. Vol. XXI, p. 4166 (Roberto Cross).

[516] Hearing Tr. Vol. XXII, p. 4431 ("In that specific year, no, they would not be subsidizing.") (Sioshansi Cross).

whether contract compensation is "out-of-market" does not determine whether a subsidy exists because the contract may be paying for value not compensated by the market.[517] Rider RRS provides value to customers no matter what market rates do. From the customer prospective, Rider RRS will operate as a valuable hedge against fluctuating market rates and stabilize customer bills. Even if rates do not increase as forecast, this protection from volatile market rates still provides a value to customers. In addition, Rider RRS provides reliability, resource diversity and cost avoidance value to customers. As such, Rider RRS does not result in an anticompetitive subsidy to FES.

In an argument analogous to the subsidy claims made by some intervenors, NOPEC and Power For Schools ("P4S") argue that Rider RRS requires their customers to pay FES twice for generation.[518] Yet customers are not paying for generation under Rider RRS; they are paying for stability, reliability, resource diversity and cost avoidance. As discussed in the Companies' Initial Brief, the insurance being provided to customers under Rider RRS is projected to generate a net credit of $561 million. Thus, NOPEC's and P4S's customers will pay once for generation and receive a separate credit that will reduce their cost of electric generation service.

b. **Rider RRS is competitively neutral and will not harm competitive markets.**

Several opponents of Rider RRS claim that the PPA supporting it could have an adverse impact on wholesale or retail markets.[519] These claims largely are based on opponents' consistent mischaracterization of Rider RRS as a subsidy, which it is not. These claims also hinge on opponents' naïve, ivory-tower characterization of existing markets as otherwise free of subsidies and impediments, which they are not. Andthese claims assume the Commission has

[517] Hearing Tr. Vol. XXVI, p. 5212 (Campbell Cross).

[518] NOPEC Brief, p. 3-5; P4S Brief, p. 3.

[519] IMM Brief, pp. 5-6; PJM Brief, p. 5; Dynegy Brief, pp. 10-15; Exelon Brief, pp. 60-61; RESA Brief, pp. 28-31.

jurisdiction over wholesale market issues within the exclusive jurisdiction of the FERC, which it does not. The question before the Commission is whether the Economic Stability Program with Rider RRS – a retail charge – "would have the effect of stabilizing or providing certainty regarding retail electric service" and is a provision to implement economic development and job retention programs. If the Commission answers this question affirmatively, the Economic Stability Program is in the public interest and should be approved.

(i) Rider RRS will not adversely affect the wholesale market.

Several opponents of Rider RRS claim that FirstEnergy's proposal could have an adverse impact on PJM's wholesale markets, speculating on the manner in which the Companies will bid the units into the PJM markets.[520] The IMM complains that the Companies are "requesting that the RRS Assets be returned to a version of the cost of service regulation regime that predated the introduction of competitive wholesale power markets."[521] PJM goes farther, and asks the Commission to impose certain wholesale market offer restrictions on the units included in Rider RRS by determining that the Commission's reasonableness standard requires the Companies to offer the Rider RRS units into PJM's wholesale markets at a price level no lower than their "actual costs."[522]

These claims, and PJM's request that the Commission dictate the terms of the Companies' wholesale offers, should all be rejected. First, these issues are beyond the scope of this proceeding. In raising them, PJM and the IMM essentially ask the Commission to take actions related to the wholesale markets that are outside of its jurisdiction. Second, other than speculation, there is no probative evidence in the record that such a directive is needed to protect

[520] IMM Brief, pp. 5-6; PJM Brief, p. 5; Dynegy Brief, pp. 10-15; Exelon Brief, pp. 60-61; RESA Brief, pp. 28-31.

[521] IMM Brief, p. 5.

[522] PJM Brief, p. 5.

retail customers. Third, the claims of wholesale market harm are wholly without merit, and ignore how PJM's market is designed (including PJM's market rules) and the prevailing business practices of many market participants.

First and foremost, PJM's request for a Commission-imposed wholesale market offer floor of "actual costs" would exceed the Commission's jurisdictional authority. The Commission does not have the authority to impose a wholesale market offer floor. Indeed, a Commission-mandated wholesale market offer floor would infringe on federal jurisdiction.[523]

The wholesale market distortion claims levied by opponents are also beyond the scope of the determination the Commission must make here concerning the lawfulness of Stipulated ESP IV and Rider RRS. The Commission's authority, and its ultimate determination, focus on whether and how the Companies may impose a *retail* charge for the purpose of achieving rate certainty and stability regarding retail electric service.[524] To be sure, the Commission must balance several price and non-price factors in determining what is prudent and reasonable to include in an ESP based on the totality of the circumstances. In doing so, however, the Commission has taken no position on alleged wholesale market impacts.[525] It should continue that practice here.

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[523] *Cf. FERC v. EPSA*, No. 14-840, slip op. at 26 (Jan. 25, 2016) ("A State could not oversee offers, made in a wholesale market operator's auction, that help to set wholesale prices. Any effort of that kind would be preempted."); *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 476 (4th Cir. 2014) (holding that the state program, which conditioned receipt of subsidies on the resource(s) clearing in the wholesale capacity market, was preempted); *PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, 252 (3rd Cir. 2014) (same). *See also Mass. Dept. Of Pub. Utils. v. United States*, 729 F.2d 886, (1st Cir. 1984) (holding that state regulatory commissions may not compel utilities to file rates that the state deems reasonable).

[524] R.C. 4928.143(B)(2)(d).

[525] *See* Case No. 11-346-EL-SSO, Opinion and Order, p. 60 (Aug. 8, 2012); Case No. 10-2929-EL-UNC, Opinion and Order, p. 13-14 (July 2, 2012) (exercising jurisdiction over wholesale capacity pricing only because expressly authorized by PJM's tariff); Case No. 14-841-EL-SSO, Opinion and Order, p. 48 (April 2, 2015) ("Some of the parties have also raised the issue of federal preemption. The Commission declines to address constitutional issues raised by the parties in these proceedings, as, under the specific facts and circumstances of these cases, such issues are best reserved for judicial determination.").

Further, PJM's request is contrary to its own market rules and prevailing practices of its market participants, and would treat FES's units different than other existing generation. PJM's market rules do not impose any offer floors on *any* existing capacity resources, regardless of whether such resources receive direct state subsidies or whether the costs of such resources get recovered through retail rates.[526] PJM has recently explained that a "very large percentage of [existing] resources offer at zero or another price *well below their avoided costs*, in order to ensure the resource clears."[527] PJM's reasoning for this behavior is that "sellers in RPM face a very real prospect that if they offer too high, they will not clear and will not realize any capacity revenues, even if the clearing price in the particular auction is set by new entry. Consequently, even aside from offer-capping rules, capacity sellers in PJM are incented to offer at or near their avoidable costs (*i.e.*, the marginal cost of capacity), so that they can clear and realize a contribution to fixed-cost recovery in the form of RPM capacity clearing prices."[528] Further, PJM has concluded that requiring all units to offer at their actual avoided cost would produce "essentially the same" market result as an approach that allows existing resources to offer at any price below the so-called "safe harbor" offer cap.[529] In that same case, FERC rejected an IMM proposal to require existing units that offer capacity below the offer cap to have a unit specific review of their offers.[530] Accordingly, PJM has acknowledged that its market rules do not impose offer floors for existing resources, that many market participants

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[526] PJM Tariff, Attachment DD §§ 5.14(h)(2), (h)(4). ISO New England, Inc. and New York Independent System Operator, Inc – who have capacity market designs similar to PJM – also do not impose offer floors on existing generating resources. *See* ISO New England Inc. Transmission, Markets, and Services Tariff §§ III.13.2.3.2(a)(iv),(c); New York ISO Market Administration and Control Area Services Tariff, Attachment H § 23.4.

[527] PJM Interconnection, L.L.C., Capacity Performance Deficiency Filing, Docket No. ER15-623-000, at 12 (filed April 10, 2015).

[528] *Id.*

[529] *See id.* at 14.

[530] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 at P 351 (2015).

submit offers for their existing resources below cost, and that these bidding practices are not meaningfully affecting the markets. PJM has not only accepted this price-taking offer behavior, but has accepted that it is rational. Now, in an abrupt about-face, PJM is asking this Commission to act beyond its jurisdiction. The Commission should reject PJM's invitation to selectively impose a discriminatory offer floor, at the undefined level of "actual costs," only on the Plants but not on any other existing capacity resources in PJM.

Finally, the claims of potential wholesale market distortion raised by PJM and the IMM, and the notion that Rider RRS would thwart the competitiveness of the wholesale markets, ignore several key futures of PJM's market design, and the reality of how PJM's market design operates in practice. While the IMM may prefer a market without vertically integrated utilities or other utilities with generation in cost-of-service, PJM has a diversity of regulatory regimes in the states. For example, as Dr. Bowring admitted, states such as Virginia, West Virginia, Kentucky, and Indiana continue to have cost-of-service generation.[531] Utilities in these states have for years sold power into the wholesale markets from generation assets that are in rate base and receive cost recovery from retail rate payers. Nothing in the record indicates, and certainly Dr. Bowring did not assert, that PJM and the IMM have ever asserted that the participation of these entities somehow threatens the competitiveness of the wholesale markets. Considered in this context, PJM's and the IMM's claims about market distortion ring hollow.[532]

While opponents object that the Commission's approval of Rider RRS may have ripple effects in the wholesale energy or capacity markets, although it should not, that should not be the

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[531] Hearing Tr. Vol. XXIV, pp. 5019-26, 5031 (Bowring Cross).

[532] Further, Rider RRS involves existing capacity resources that are already a part of the PJM market. Nothing in the PJM rules prevents existing resources from offering into the capacity market as price-takers – including existing resources receiving state-funded subsidies or other existing resources that are completely insulated from the market's pricing signals (such as resources whose costs are guaranteed to be recovered through cost-of-service retail rates).

Commission's concern. The Commission's role is to advance state policy in favor of rate stability, resource diversity and system reliability. If advancing those policy objectives has an incidental effect elsewhere, so be it. As the Fourth Circuit stated in *Nazarian*, "It goes without saying that not 'every state statute that has some indirect effect' on wholesale rates is preempted, *Schneidewind*, 485 U.S. at 308, 108 S.Ct. 1145, for 'there can be little if any regulation of production that might not have at least an incremental effect on the costs of purchasers in some market,' *Nw. Cent. Pipeline Corp.*, 489 U.S. at 514, 109 S.Ct. 1262."[533]

Nor should the Commission be concerned by the erroneous argument that Rider RRS may have an effect on the market clearing price. As the Third Circuit wrote in rejecting the same argument:

> the law of supply and demand is not the law of preemption. When a state regulates within its sphere of authority, the regulation's incidental effect on interstate commerce does not render the regulation invalid. . . . Indeed, were we to determine otherwise, the states might be left with no authority whatsoever to regulate power plants because every conceivable regulation would have some effect on operating costs or available supply. That is not the law.[534]

The Commission can and should act to maintain resource diversity and to promote retail price stability.

(ii) Rider RRS will not adversely affect the retail market.

Some intervenors claim that Rider RRS will adversely affect Ohio's retail market. Exelon asserts, for example, that Rider RRS "destroys benefits of fixed-price contracts."[535] It argues that customers who would be otherwise "shielded from market volatility under a fixed-

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[533] *Nazarian*, 753 F.3d at 478.

[534] *Solomon*, 766 F.3d at 255.

[535] Exelon Brief, pp. 57-58.

price contract" will now be exposed to variable charges under Rider RRS.[536] The proposition underlying Exelon's argument – namely, that customers with fixed-price contracts are shielded from volatility – is wrong.

No customer is completely shielded from risk, and customers with fixed-price contracts do experience significant volatility. As explained by Company witness Mikkelsen, even with respect to fixed-price contracts, a customer's retail electric price includes a risk premium associated with anticipated wholesale market price volatility that CRES providers "bake into" subsequently available fixed-price contract offers.[537] In fact, the record demonstrates that a customer may experience volatility upwards of 25% when moving from one fixed-price contract to another.[538] And in contrast to the 8-year stability mechanism provided by the Economic Stability Program, no CRES provider in the Companies' service area is offering on the Commission's "Apples-to-Apples" website any contract for longer than 36 months.[539] Far from destroying the benefits of fixed-price contracts, Rider RRS provides customers with protections that such contracts do not.

Still, Exelon contends that the Economic Stability Program does not provide a hedge because, under the Companies' projections, Rider RRS will result in a charge in the first three

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[536] Exelon Brief, p. 58.

[537] Mikkelsen Rebuttal, p. 5; Hearing Tr. Vol. XXXIV, pp. 7052-7053 (Mikkelsen Rebuttal Cross).

[538] Hearing Tr. Vol. XXV, pp. at 4954-4956; 4958-4959 (Haugen Cross); Company Ex. 82 (Sept. 2013 Apples-to-Apples chart); Company Ex. 83 (June 2014 Apples-to-Apples chart); Hearing Tr. Vol. XXVI, pp. 5243-5244 (Campbell Cross); Company Ex. 105 (March 2014 Apples-to-Apples chart); Company Ex. 106 (March 2015 Apples-to-Apples chart).

[539] Strah Direct, p. 13. Even with respect to 36 month contracts, as of September 11, 2015, according to the Apples-to-Apples website, there were only four such CRES contracts available to customers in the Companies' service territories. Hearing Tr. Vol. XXX, pp. 6288-6289 (Choueiki Cross).

Further, though NOPEC touts a 9-year fixed-discount option available to certain customers, NOPEC's program provides only a fixed *discount* on the price to compare, not a fixed *price* for customers. NOPEC Brief, p. 25.

years of ESP IV.[540] But Exelon's argument is fundamentally wrong. Rider RRS is not a hedge merely because it will provide credits to customers. As explained in the Companies' Initial Brief:

> Rider RRS is analogous to car insurance – even if the car owner does not have an accident, the owner still has the twin benefits of risk protection and functioning transportation. Equivalently, Rider RRS provides risk protection to retail electric customers and, if prices defy widely-held expectations and long-term trends and do not increase significantly, customers continue to receive the benefit of historically low prices.[541]

Exelon further argues that Rider RRS will negatively affect retail competition because it provides FES with a competitive advantage through a "guaranteed subsidy" that will allow it to make offers to shopping customers that are not reflective of market prices.[542] As a threshold matter, the claim that FES has a competitive advantage under Rider RRS is completely without merit. Exelon's argument fails to recognize that whenever market revenues are higher than FES's costs, at such times FES is forsaking profits, which will instead be enjoyed by the Companies' customers.[543] Additionally, Exelon's argument grossly mischaracterizes Rider RRS, which is not a subsidy, and assumes that FES is guaranteed to recover its costs, which it is not. As described in Section III.A.3.d., below, the Final Term Sheet imposes significant obligations

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[540] Exelon Brief, p. 42.

[541] Companies' Initial Brief, p. 22; Hearing Tr. Vol. XXII, pp. 4383-4384 (Baron Cross) (OEG witness Baron confirming that customers will benefit from Rider RRS even if retail prices remain low – "You are betting against the bad outcome, if you don't have that bad outcome, the premium that you paid for that bet will still be worth it.").

[542] Exelon Brief, p. 56. EPSA/P3 raise a similar claim with respect to FES's alleged competitive advantage in wholesale auctions. EPSA/P3 Brief, p. 38. In support of their argument, EPSA/P3 cite only the pre-filed testimony of Exelon witness Campbell, which is based on nothing more than his say-so. *Id*. Their claim is left wholly unsubstantiated by facts or by Ohio's recent history, which has seen other stability riders have no material impact on wholesale markets. Regardless, as demonstrated above, the alleged impacts of Rider RRS on wholesale markets are a topic for FERC, not the Commission.

[543] *See* Hearing Tr. Vol. XXVI at 5237-40 (Campbell Cross).

on FES that incentivize it to carefully control costs or risk not recovering them.[544] In any event, Exelon's vague and speculative assertion that FES will be able to make offers to shopping customers that other CRES providers can't makes little sense. Simply put, FES would have no rational incentive to undercut itself by selling at below-market prices to shopping customers when it could sell at market elsewhere.

OCC/NOAC take a different, but no more successful, approach to arguing that Rider RRS will adversely affect the retail market. Their approach is simple: they argue that OCC/NOPEC witness Wilson's analysis shows that Rider RRS will result in net charges to customers, which is detrimental to the retail market.[545] Their reliance on Mr. Wilson's analysis dooms OCC/NOAC's argument. As demonstrated above, Mr. Wilson's result-oriented methodology was seriously flawed, ad hoc and unreliable.

In sum, Exelon and OCC/NOAC's arguments concerning Rider RRS's effect on the retail market are unsupported by anything other than their speculative and unsubstantiated allegations. Before this Commission, that is insufficient. The record illustrates that Rider RRS is a stability mechanism that serves as a valuable hedge for all of the Companies' customers.

c. Rider RRS provides long-term stability to customers.

Company witness Rose testified at length that power prices, the main input to retail power supply, have been extremely volatile over the last decade in PJM.[546] Despite this evidence, Sierra Club and ELPC argue that the Companies have not demonstrated that customers

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[544] Similarly to Exelon, Dynegy argues that FES has no incentives to control costs, which disadvantages other CRES suppliers. Dynegy Brief, p. 16.

[545] OCC/NOAC Brief, p. 142.

[546] Rose Direct, pp. 21-32.

face retail rate volatility.[547] However, Company witness Mikkelsen provided four examples of retail rate volatility over the last few years for the Companies' retail customers:

1. Customers who take service under variable price contracts with CRES providers based on Day-Ahead or Real Time LMPs with a retail adder, who saw a significant increase in volatility for the last two planning years compared to the first two planning years the Companies were in PJM;

2. Rider ELR customers, who saw a roughly 350% increase in the number of their Economic Buy-Through hours (hours when the Day-Ahead LMP exceeds 1.5 times the average auction clearing price for the delivery year) from delivery years 2011/2012 and 2012/2013 to delivery years 2013/2014 and 2014/2015;

3. SSO customers who, after the Polar Vortex, faced retail rate volatility when higher auction clearing prices were included in SSO rates that went into effect June 1, 2014 and June 1, 2015; and

4. CRES customers, for whom the average CRES offer for a 12-month, fixed price full requirements product increased 32% in the first four full months after the Polar Vortex.[548]

Sierra Club's attempt to downplay these examples by asserting that Ms. Mikkelsen's analysis shows only that "there may have been some increase in retail rates in the months after the polar vortex"[549] only addresses two of the four examples. Also, Sierra Club dismisses past events, contending they do not speak to whether power prices are expected to be volatile in the future,[550] even though its Brief advocates using past experience to predict the future in other contexts.

EPSA/P3 and Exelon argue that retail prices are not nearly as volatile as wholesale prices. They also contend that SSO customers and shopping customers with fixed-price contracts do not experience volatility, and further that shopping customers with fixed-price contracts may experience price discounts for committing to long-term purchases for up to three

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[547] Sierra Club Brief, p. 78; ELPC Brief, p. 37.

[548] Mikkelsen Rebuttal, pp. 2-4.

[549] Sierra Club Brief, p. 79.

[550] Sierra Club Brief, p. 79 fn. 310.

years. They base these arguments on the testimony of EPSA/P3 witness Dr. Kalt.[551] As explained further below, SSO rates remain subject to volatility as new SSO supply contracts begin, and shopping customers will see the effects of volatility between successive CRES contracts. Rider RRS provides a different type of mitigation that compliments the mitigation provided by SSO service or fixed price CRES contracts. Further, on cross-examination, Dr. Kalt admitted that he had not compared wholesale electric prices against the prices that resulted from Companies' competitive bidding process for SSO load.[552] With regard to fixed price CRES contracts, he did not know whether his research on the Commission's Apples to Apples Website covered a majority of CRES offers available to customers on the market.[553] And with respect to discounts for shopping customers for fixed price contracts of up to three years, Dr. Kalt did not know whether capacity prices in ATSI in the first of the three years were more than two times the capacity prices in the second and third years.[554]

Sierra Club, OCC/NOAC, EPSA/P3 and Exelon also argue that Rider RRS will not address retail rate volatility, but instead will cause instability.[555] These parties contend that Rider RRS is not counter-cyclical as the Companies suggest, because Rider RRS will be based on forecasted revenues and annually reconciled to reflect actual results, while generation for SSO customers and shopping customers will be supplied with fixed contracts based on forward market prices. These parties argue that Rider RRS will be out of step with wholesale market prices and retail generation rates.[556] However, Company witness Savage explained at hearing

[551] EPSA/P3 Brief, p. 16; Exelon Brief, pp. 15-16.

[552] Hearing Tr. Vol. XXVIII, pp. 5670-5671 (Kalt Cross).

[553] Hearing Tr. Vol. XXVIII, p. 5672 (Kalt Cross).

[554] Hearing Tr. Vol. XXVIII, p. 5674 (Kalt Cross)

[555] Sierra Club Brief, pp. 77-78; OCC/NOAC Brief, pp. 85-88; EPSA/P3 Brief, p. 16; Exelon Brief, p. 16.

[556] Sierra Club Brief, p. 78; EPSA/P3 Brief, p. 16; Exelon Brief, p. 16.

that she would not expect reconciliation components to have a material effect on the overall benefit that is expected over the term of Rider RRS.[557]

OOC/NOAC misconstrue Ms. Mikkelsen's testimony to contend that Rider RRS cannot be considered a hedge because Rider RRS is not solely dependent on market prices.[558] To be sure, when asked whether a hedge is "an instrument that typically addresses a single risk, such as market prices," Ms. Mikkelsen agreed.[559] OCC/NOAC fail, however, to provide the rest of her answer. The complete answer was:

> I think a hedge is designed to address the risk associated with adverse changes in market prices, which is why I don't really think of a fixed-rate contract as a hedge. A fixed-rate contract is more a smoothing out of the risk associated with the volatility over the term of the contract built into one levelized price; where a hedge as you point out, really works to reduce the costs because it will move counter to the market and provide a reduction in the costs rather than a smoothing out, as you would see in a fixed-price contract.[560]

Moreover, the Commission already considered and dismissed these timing arguments. In its *AEP ESP3* Order, the Commission found that the PPA Rider is "intended to mitigate, by design, the effects of market volatility, providing customers with more stable pricing and a measure of protection against substantial increases in market prices."[561] Notwithstanding differences in the timing of the rise and fall of AEP's proposed PPA Rider versus fluctuations in market prices, the Commission recognized that "[a]t its core, the PPA rider is expected to move in the opposite direction of wholesale market prices, causing a rate stabilization effect."[562] The Commission further explained that the credit or charge based on the difference between

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[557] Hearing Tr. Vol. XVIII, p. 3605-3606 (Savage Cross).

[558] OCC/NOAC Brief, pp. 87-88.

[559] Hearing Tr. Vol. XXXIV, p. 7032 (Mikkelsen Cross).

[560] Hearing Tr. Vol. XXXIV, p. 7032 (Mikkelsen Cross).

[561] *AEP ESP3* Order at 21.

[562] *AEP ESP3* Order at 21.

wholesale market prices and OVEC costs would offset volatility in the wholesale market and smooth out market based prices paid by customers:

> Although several intervenors dispute the value of the proposed hedging mechanism and its use as a means to promote rate stability, there is no question that the PPA rider would produce a credit or charge based on the difference between wholesale market prices and OVEC's costs, offsetting, to some extent, the volatility in the wholesale market. The impact of the PPA rider would be reflected as a charge or credit for a generation-related hedging service that stabilizes retail electric service, by smoothing out the market based rates paid by shopping customers to their CRES providers, as well as the market based rates paid by SSO customers, which are determined by a series of auctions that reflect the prevailing wholesale prices for energy and capacity in the PJM markets. Because AEP Ohio has demonstrated that the proposed PPA rider would, in theory, have the effect of stabilizing or providing certainty regarding retail electric service, the Commission finds that the third criterion of R.C. 4928.143(B)(2)(d) has been met.[563]

Accordingly, arguments that the reconciliation of Rider RRS will cause a mismatch between Rider RRS credits and fluctuations in market prices must be rejected.

ELPC further argues that Rider RRS's rate stabilizing effects are minor.[564] To the contrary, Company witness Mikkelsen testified to the mitigating value of Rider RRS. Ms. Mikkelsen explained that over the term initially proposed, Rider RRS would result in a 3% reduction in estimated generation charges, and a 2% reduction in estimated total retail charges.[565]

(i) Customers cannot hedge long-term market risks themselves.

NOPEC argues that customers can hedge long-term market risk themselves, pointing to its percent off the price to compare ("PTC") contract as an example of such a hedge.[566] This

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[563] *AEP ESP3* Order at 21.

[564] ELPC Brief, pp. 37-38.

[565] Mikkelsen Rebuttal, pp. 4-5.

[566] NOPEC Brief, p. 28.

misunderstands what a hedge is. To use a simple example, if energy prices increase significantly then under Rider RRS customers are projected to receive a credit. Under the NOPEC contract, if the PTC increases then the price charged to NOPEC customers also increases. A percentage off the PTC is not a hedge on long-term market movements, it is a discount.

ELPC argues that customers can purchase hedges through a three-year CRES contract.[567] Exelon witness Campbell claims that Rider RRS is unnecessary because CRES providers already offer customers all of the hedging products that they could possibly need, pointing to several 36-month offers currently available to customers.[568] "Without a non-bypassable Rider RRS, CRES providers can provide retail customers with a true-fixed generation product."[569]

The long-term hedge afforded by Rider RRS simply cannot be matched by shopping with a CRES provider for a fixed-price contract. The undisputed record evidence shows that no CRES provider is offering the Companies' customers a fixed-price contract of longer than 36 months, let alone an eight-year hedge.[570] Indeed, as of September 11, 2015, according to the Apples-to-Apples website, there were only four 36-month CRES contracts in the Companies' service territories for shopping customers to choose from.[571]

Moreover, it is not uncommon for shopping customers to experience increases in price volatility when transitioning from one fixed-price contract to the next. Such price volatility can be significant and, as the record evidence demonstrates, may range upwards of 25%.[572]

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[567] ELPC Brief, p. 39.

[568] Campbell Direct, p. 15.

[569] Campbell Direct, p. 15.

[570] Strah Direct, p. 13. And, indeed, no CRES provider is offering the opportunity of an eight-year hedge. Hearing Tr. Vol. XXVI, p. 5333 (Bennett Cross).) *See also* Hearing Tr. Vol. XXII, p. 4527 (Wilson Cross).

[571] Hearing Tr. Vol. XXX, pp. 6288-89 (Choueiki Cross). *See also* Company Ex. 130 (Energy Choice Ohio Apples to Apples Comparisons Chart (Sept. 11, 2015)).

[572] Hearing Tr. Vol. XXV, pp. 4954-56, 4958-59 (Haugen Cross); Company Ex. No. 82 (Sept. 2013 Apples-to-Apples chart); Company Ex. No. 83 (June 2014 Apples-to-Apples chart); Hearing Tr. Vol. XXVI, pp. 5243-44

Constellation offerings for 12-month fixed price contracts provide a case in point. An Apples-to-Apples chart dated March 21, 2014, lists a 12-month-fixed price offering from Constellation for 6.89 cents per kilowatt-hour.[573] Exactly one year later, in an Apples-to-Apples listing dated March 20, 2015, a similar 12-month fixed-price contract ballooned in price to 8.59 cents per kilowatt-hour – an increase in the range of 20 to 25%.[574]

Moreover, severe weather events such as the 2014 Polar Vortex and the 2015 Siberian Express can also have an untoward effect on fixed-price offerings from CRES providers. For example, the average CRES offer for a twelve-month fixed price, full requirements product in the Companies' service territory increased by 32% in the first four full months after the Polar Vortex.[575] Further, as Ms. Mikkelsen testified at hearing:

> Perhaps the most illustrative [example]…is looking at the difference between the average offer price in February of 2014 versus March of 2014 and the significant increase month over month that occurred in those as well as the number of suppliers who dropped out of the market or removed making offers in the market during that time frame, demonstrating, again, the impact of the volatility even on the fixed price market.[576]

Mr. Campbell also ignores the fact that a shopping customer's retail electric price includes a risk premium associated with anticipated wholesale market price volatility that CRES providers "bake into" subsequently available fixed-price retail contract offers.[577] Hence, Mr. Campbell's blithe assumption that fixed-price CRES offerings are somehow comparable to the long-term hedge provided by Rider RRS is wholly unsupported by the record.

(Campbell Cross); Company Ex. No. 105 (March 2014 Apples-to-Apples chart); Company Ex. 106 (March 2015 Apples-to-Apples chart).

[573] *See* Company Ex. 105.

[574] *See* Company Ex. 106 and Hearing Tr. Vol. XXVI, pp. 5243-44 (Campbell Cross).

[575] Hearing Tr. Vol. XXXIII, p. 6911 (Mikkelsen Cross).

[576] Hearing Tr. Vol. XXXIII, pp. 6963-64 (Mikkelsen Cross).

[577] Mikkelsen Rebuttal, p. 5; Hearing Tr. Vol. XXXIV, pp. 7052-53 (Mikkelsen Rebuttal Cross).

Nor can customers purchase a hedge through SSO pricing, as ELPC, OCC and NOPEC suggest. ELPC's belief that SSO pricing is fixed for three years is simply incorrect.[578] The Companies' Initial Brief explained why OCC and NOPEC are incorrect to suggest that staggering and laddering of SSO supply contracts makes Rider RRS's mitigation of market price fluctuations unnecessary.[579] Rider RRS provides a type of retail rate volatility mitigation that staggering and laddering of SSO supply contracts does not, and Rider RRS provides mitigation to a broader group of customers.[580]

(ii) There is no need to "guarantee" any specific level of customer savings.

Several intervenors suggest that FES and/or the Companies should guarantee the level of customer savings contained in the Company's projections.[581] This argument misunderstands the essential nature of a hedge. Under this hedge, like any other, the precise benefits to customers will vary based on market conditions. This does not mean the Company's forecast is inaccurate or this is somehow a bad deal for customers. Instead, this simply reflects the fact that there is some degree of variability in all forecasts, and the benefits to customers could be greater or less than projected by the Companies.

It is important to note that even through the monetary benefit to customers will fluctuate with market prices, that does not mean the possibility of a benefit to customers goes away. In addition to the monetary benefits that customers will receive if market prices rise, customers will also receive economic benefits through the rate stability made possible by the continued

[578] ELPC Brief, p. 39.

[579] OCC Brief, pp. 83-86; NOPEC Brief, pp. 24-25.

[580] Companies' Initial Brief, p. 44.

[581] RESA p. 46; Sierra Club, p. 61; City of Cleveland, p. 6; EPSA/P3 p. 10.

operation of the Plants, avoid possible transmission costs, and help insure that Ohio customers receive reliable service.

(iii) Including both nuclear and coal units in Rider RRS increases its value as a hedge.

Exelon argues that the majority of the benefit of the hedge is provided by the coal plants, and that Davis-Besse provides very little projected benefit to customers.[582] Exelon, of all parties, should understand that there is a significant value to nuclear plants. Having a nuclear unit included in Rider RRS reduces the risk to customers of a regulatory or technological change adverse to fossil plants. Therefore, even if the benefit associated with the coal units is higher than the benefit of Davis-Besse today, having a variety of fuel sources is still a significant benefit to customers.

d. **The Companies and FES have an incentive to manage the Plants appropriately.**

Because of the Commission's independent prudence review and the obligations of the respective parties under the Final Term Sheet, there should be little doubt that the Companies and FES both have substantial incentives to manage their respective obligations properly regarding the Plants and the OVEC entitlement. Nonetheless, some intervenors apparently believe that commitments under the Final Term Sheet can be brushed aside and that the Commission's prudence review isn't really so potent. As demonstrated below, their arguments should be rejected.

(i) The material provisions of the Term Sheet are final and the Companies are not at risk from unilateral termination of the agreement.

As a threshold matter, Sierra Club and Exelon, in their blunderbuss attack on the Stipulated ESP IV, assert that because the Final Term Sheet has not yet become a finalized

[582] Exelon Brief, p. 37.

contract, the Final Term Sheet's provisions are in doubt.[583] To be sure, the wholesale transaction contemplated by the Final Term Sheet is not before the Commission. Nevertheless, the Companies' witnesses have unequivocally stated that the Final Term Sheet contains all the material terms and conditions of the proposed transaction, which would be incorporated into a purchase power agreement.[584] Notably, Sierra Club and Exelon can point to no provision allegedly missing from the Final Term Sheet that would prevent the Commission from reaching its determination on this record.[585]

Sierra Club also worries that FES could unilaterally terminate its agreement with the Companies without consequence. Indeed, Sierra Club widely asserts that the Final Term Sheet would "likely" preclude the Companies from recovering the revenues from selling the output of the Plants and OVEC entitlement.[586] Sierra Club's speculation finds no support in this record. Section 20 of the Final Term Sheet provides only extremely narrow termination rights – and that relates to a governmental approval needed at consummation of the transaction that is subsequently withdrawn.[587] Otherwise, FES does not have the option of terminating the contract.

Regardless, contrary to Sierra Club's claims, Company witness Moul explained that if FES terminated the agreement prematurely, it would be in breach.[588] He further stated that FES would then be responsible under Section 19 of the Final Term Sheet for paying to the Companies

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[583] Sierra Club Brief, pp. 48, 54-55; Exelon Brief, p. 13-14.

[584] *See* Hearing Tr. Vol. I, pp. 55-58 (Mikkelsen Cross); Hearing Tr. Vol. IV, p. 869 (Strah Cross); *see also* Companies' Initial Brief, p. 4 n. 8.

[585] Sierra Club raises the specter of the purchase power agreement being modified even after it has become final. Sierra Club alleges that Company witness Lisowski acknowledged that FES could indeed have that incentive. Sierra Club's argument is of no moment. In the testimony cited by Sierra Club, Mr. Lisowski expressed doubt that FES could renegotiate the agreement even if it wanted to because the Companies would have to mutually agree. Hearing Tr. Vol. VIII, pp. 1723-24 (Lisowski Cross).

[586] Sierra Club Brief, pp. 55-56.

[587] Company Ex. 156, Section 20; Moul Rebuttal, p. 6; Hearing Tr. Vol. XXXII, p. 6567 (Moul Cross).

[588] Moul Rebuttal, p. 6; Hearing Tr. Vol. XXXII, p. 6622 (Moul Cross).

the difference between contract payments and the amount of revenue that the Companies would have received for the output of the Plants: *i.e.*, the Companies' direct damages.[589] Sierra Club blithely asserts that Mr. Moul's testimony is unpersuasive on this point because he "is not an attorney."[590] Yet, Sierra Club raised no objection when Mr. Moul explained his reading of Section 19 on the basis of his expertise and in response to Sierra Club counsel's questions.[591] Indeed, their complaint about Mr. Moul makes little sense. As a high ranking executive of one of the parties to the Final Term Sheet and as a witness designated to discuss the proposed transaction, Mr. Moul's understanding of the proposed transaction is highly probative. In short, though Sierra Club might not like the record it developed for itself, it must live with it. A fair reading of the Final Term Sheet and Mr. Moul's testimony in support demonstrate that even if FES breaches the agreement, the Companies' will be fairly compensated.

OCC/NOAC suggest that Section 20 of the Final Term Sheet would permit the Companies to terminate the PPA early if the Commission were to disallow cost recovery in Rider RRS.[592] OCC/NOAC are wrong. Section 20 provides the Seller – FES – the right to terminate if, and only if, a Governmental Approval required to consummate the transaction is lacking and cannot be obtained.[593] "Governmental Approval" does not include the Commission.[594] Thus, Section 20 does not give the Companies the right to terminate the agreement if the Commission disallows costs.

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[589] Company Ex. 156, Section 19; Moul Rebuttal, p. 6; Hearing Tr. Vol. XXXII, p. 6567 (Moul Cross). Sierra Club tries to do an end run around Mr. Moul's testimony by characterizing the Companies' direct damages as lost "future profits." Sierra Club Brief, p. 56. Sierra Club's argument is misplaced, however, considering that the proposed transaction is revenue neutral to the Companies.

[590] Sierra Club Brief, p. 57.

[591] Hearing Tr. Vol. XXXII, p. 6566 (Moul Cross).

[592] OCC/NOAC Brief, pp. 131-32.

[593] Company Ex. 156, Section 20.

[594] Company Ex. 156, p. 15 (definition of Governmental Approval).

(ii) The Companies have strong incentives to maximize revenues.

The intervenors' speculation that the Companies lack incentives to offer the Plants' output and to maximize revenues in the PJM market is not supported by the record and is, in fact, directly refuted by it.[595] From the outset, the Companies have been committed to maximizing revenues for the benefit of customers by working to ensure the efficient operation of the Plants. Knowing that the Plants' costs and revenues would be subject to rigorous Commission review, the Companies negotiated a host of customer protections into the Final Term Sheet. The Final Term Sheet, for example, grants the Companies the right to audit the costs charged to them.[596] Further, FES's Operating Work at the Plants is required to be governed by Good Utility Practice.[597] The Companies also negotiated the authority to review and comment upon FES's capital improvements plan and scheduled outage program.[598] The Final Term Sheet plainly provides robust protections for customers on both the cost and revenue sides of the transaction.

The testimony of the Companies' witnesses is also telling. In response to questions from the Attorney Examiner, Company witness Ruberto, who would be responsible for the Companies' strategies for offering the output from the Plants and the OVEC entitlement, explained the Companies' intent to actively manage bids into PJM:

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[595] *See* Dynegy Brief, p. 13; RESA Brief, p. 29.

[596] Company Ex. 156, Section 18; Ruberto Direct, p. 9; Hearing Tr. Vol. XIII, pp. 2878, 2879 (Ruberto Cross); Hearing Tr. Vol. XXIV, p. 4879 (Kahal Cross) (admitting to audit rights and consultation on capital projects); Hearing Tr. Vol. XXX, p. 6301 (Choueiki Cross) (same).

[597] Company Ex. 156, Section 11; Ruberto Direct, p. 9; Hearing Tr. Vol. XIII, pp. 2850, 2892 (Ruberto Cross); Hearing Tr. Vol. XIV, pp. 300-01, 3003 (Ruberto Cross); Hearing Tr. Vol. XXI, p. 4066 (Chriss Cross); Hearing Tr. Vol. XXI, pp. 4233-34 (Cole Cross); Hearing Tr. Vol. XVIII, p. 5620 (Kalt Cross); Hearing Tr. Vol. XXXI, p. 6418 (Comings Cross).

[598] Company Ex. 156, Section 12; Ruberto Direct, p. 9; Hearing Tr. Vol. XIII, pp. 2779-82 (Ruberto Cross); Hearing Tr. Vol. XXX, p. 6301 (Choueiki Cross). Further, customers would be under no obligation to pay approved capital costs after the end of the PPA, even if such costs were amortized beyond the term of the PPA. Hearing Tr. Vol. XXI, pp. 4064-65 (Chriss Cross); Hearing Tr. Vol. XXVIII, pp. 5620-21 (Kalt Cross).

> What our intent would be is to participate in the capacity market which, of course, is one revenue piece within PJM. Additionally the day-ahead market is generally where most generation is marketed in PJM, and I would expect we would do that. There is additionally some real-time market participation for any generating unit simply because its output may be more or less than what you cleared in the day-ahead market. So I would view it as actively managing all three of those components. And on a daily basis my group would be responsible to make those offers into the market in a manner to maximize those revenues for the company.[599]

Company witness Mikkelsen also clearly stated on the record that in order to provide a hedge for customers, the Companies' intent is to sell the output into the PJM markets.[600]

And, as the Companies' Initial Brief showed, although the Commission will have no authority to direct the Companies' offers of capacity into the PJM market, the revenues generated from the PJM market will be subject to after-the-fact Commission review.[601] Indeed, Company witness Mikkelsen testified that if there were "a determination that either the underlying costs or the underlying revenues are unreasonable, then . . . the financial risk of those unreasonable determinations would be transferred from the companies' customers to the company."[602] The financial risk of an unreasonableness determination and the disallowance of cost recovery gives the Companies ample financial incentives when offering the Plants' and OVEC's output into the PJM markets.

Instead of acknowledging the record evidence and the financial risk of Commission-ordered disallowances, some intervenors resort to baseless allegations. Dynegy argues, for

[599] Hearing Tr. Vol. XIV, p. 3033 (Ruberto Recross).

[600] Hearing Tr. Vol. XXXVI, pp. 7686-87 (Mikkelsen Cross) ("Again, . . . the rider RRS provision is intended to perform as a hedge to market prices for our customers to provide a stabilizing benefit to those customers. So the intention is that the power would be sold into the energy and capacity markets.").

[601] Companies' Initial Brief, p. 74; Mikkelsen Fifth Supp., p. 4; Hearing Tr. Vol. XIV, p. 3002 (Ruberto Cross); Hearing Tr. Vol. XXXVI, p. 7617 (Mikkelsen Cross).

[602] Mikkelsen Second Supp., p. 12; Hearing Tr. Vol. I, pp. 60-61 (Mikkelsen Cross); Hearing Tr. Vol. XXXVI, p. 7622 (Mikkelsen Cross).

example, that the "Companies have no financial incentive to act in an economically rational manner for the purchased output from the PPA units and the OVEC entitlement."[603] RESA restates this claim.[604] OCC/NOAC assert a related argument that the Companies "would have little incentive to vigilantly review the reasonableness of the FES costs at [the Plants]."[605] These arguments not only ignore the record, they also demonstrate a lack of confidence in the efficacy of the Commission's after-the-fact prudence review, despite the Commission's recent history of disallowances.[606]

In that same vein, EPSA/P3 argue that "customers bear the risk of [capacity] performances penalties under Rider RRS" and express doubts about the potency of the Commission's prudence review.[607] This is another misstatement of the facts in the record. As discussed and as the record demonstrates, all the revenues and costs included in the Rider RRS calculation will be subject to Commission review.[608] Further, the Third Supplemental Stipulation explicitly provides that potentially disallowed costs also include those associated with performance requirements in PJM's markets.[609] Given the risk of disallowance of cost recovery, which EPSA/P3 point out could be substantial,[610] it is not surprising that Company

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[603] Dynegy Brief, p. 13.

[604] RESA Brief, p. 29.

[605] OCC/NOAC Brief, p. 81.

[606] *See, e.g.*, *In re Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Co.*, 11-5201-EL-RDR, 2013 Ohio PUC LEXIS 159, at *61, Opinion and Order (Aug. 7, 2013) (disallowing $43,362,796.50); *In re Application of Duke Energy Ohio, Inc. to Establish and Adjust the Initial Level of its Distribution Reliability Rider*, 09-1946-EL-RDR, Opinion and Order, pp. 24-25 (Jan. 11, 2011) (reducing recovery of labor expenses by $14,368,667).

[607] EPSA/P3 Brief, p.11.

[608] Mikkelsen Fifth Supp., p. 4; Hearing Tr. Vol. XIV, p. 3002 (Ruberto Cross); Hearing Tr. Vol. XXXVI, p. 7617 (Mikkelsen Cross).

[609] Third Supp. Stip., Section V.B.3.a; Hearing Tr. Vol. XXXVI, p. 7706 (Mikkelsen Cross).

[610] EPSA/P3 Brief, p. 11.

witness Ruberto explained that it would certainly be the Companies' intent and expectation to operate the plants in a manner that reduces or eliminates nonperformance charges.[611]

For its part, NOPEC raises the absurd argument that the Companies would have an incentive to economically withhold the Plants and the OVEC Entitlement from PJM in order to benefit other affiliated generation assets.[612] As an initial matter, the PJM tariff includes a must-offer requirement that obligates existing generators to submit offers into the PJM capacity market.[613] The preposterous nature of NOPEC's position is reinforced by the testimony of its own witness Wilson. Mr. Wilson agreed at hearing that FERC rules prohibiting market manipulation would apply to economic withholding for the purpose of raising prices for the benefit of affiliated plants.[614] He further agreed that FERC has an enforcement office and divisions within that office that conduct investigations, oversee the energy market and conduct analytics and surveillance on the markets.[615] These divisions, Mr. Wilson admitted, monitor PJM and other wholesale markets for instances of market manipulation, including economic withholding.[616] Additionally, Mr. Wilson admitted that PJM's Market Monitor also reviews trades and trading patterns.[617] NOPEC's suggestion that the Companies would even consider exposing themselves to the immense risk of participating in illegal activity in markets that exist under perpetual and serious scrutiny is divorced from any evidence in this record and not worthy of serious consideration.

[611] Hearing Tr. Vol. XIII, pp. 2809-10 (Ruberto Cross).

[612] NOPEC Brief, pp. 9-10.

[613] PJM Tariff Attachment DD § 6.6.

[614] Hearing Tr. Vol. XXII, p. 4532 (Wilson Cross).

[615] Hearing Tr. Vol. XXII, pp. 4532-33 (Wilson Cross).

[616] Hearing Tr. Vol. XXII, p. 4533 (Wilson Cross).

[617] Hearing Tr. Vol. XXII, p. 4533 (Wilson Cross).

(iii) FES has strong incentives to only make the necessary investments in the Plants.

The provisions of the Final Term Sheet and the fact that FES will rationally protect its own interests demonstrate that FES has strong incentives to make only the necessary investments in the Plants. Several intervenors argue to the contrary, however, and levy two general accusations at FES. At one extreme, Sierra Club, OCC/NOAC and OMAEG assert that FES has *an incentive to over-invest in the Plants*. At the other, the IMM and Dynegy claim that FES has no incentive to ensure the reliable operation of the Plants and thus will *under-invest in the Plants*. ***EPSA/P3 inexplicably make both of these allegations in the same brief***.[618] Both of these things cannot be true. And, as demonstrated below, neither is true.

As an initial matter, the arguments of the intervenors in the "over-invest" camp,[619] by assuming that FES is guaranteed to recover its costs, overlook FES's obligation to perform Operating Work at the Plants in accordance with Good Utility Practice.[620] Company witness Mikkelsen explained that the Companies will not compensate FES for costs incurred as a result of FES's failure to follow Good Utility Practice: "[s]o to the extent that FES were to pass along costs that were in excess of those that would be expected by good utility practice, there would be no guarantee and, in fact, quite the opposite. The term sheet would suggest that the companies would not pay for those costs."[621] Further, these intervenors again give short shrift to the Commission's reasonableness review. Even if the Companies agree that FES has used Good

[618] EPSA/P3 Brief, p. 25 (Rider RRS "leav[es] FES with minimal incentives to make . . . additional investments in capital and its daily operations to avoid outages."), p. 36 ("Rider RRS incentivizes FES to overinvest in capital.").

[619] *See* Sierra Club Brief, pp. 51-53; OCC/NOAC Brief, p. 81; OMAEG Brief, p. 64.

[620] Company Ex. 156 Section 11; Ruberto Direct, p. 9; Hearing Tr. Vol. XIII, pp. 2850, 2892 (Ruberto Cross); Hearing Tr. Vol. XIV, pp. 3001-01, 3003 (Ruberto Cross); Hearing Tr. Vol. XXI, p. 4066 (Chriss Cross); Hearing Tr. Vol. XXI, pp. 4233-34 (Cole Cross); Hearing Tr. Vol. XVIII, p. 5620 (Kalt Cross); Hearing Tr. Vol. XXXI, p. 6418 (Comings Cross).

[621] Hearing Tr. Vol. I, pp. 50-51 (Mikkelsen Cross).

Utility Practice, such an agreement in no way prevents the Commission from disagreeing in an after-the-fact prudence review.[622] In addition, Company witness Mikkelsen explained that the Final Term Sheet provides for the Companies to have an active role in the review and finalization of the annual capital expenditures plans for the Plants.[623] The Companies are motivated to actively review the annual capital expenditures plans because, as noted, the costs they incur are subject to reasonableness review by the Commission. Moreover, the Final Term Sheet states that to the extent that a capital expenditure would render a plant uneconomic, the parties may agree to replace the plant's output or drop the plant from the wholesale transaction and correspondingly reduce FES's supply obligations.[624]

Regarding capital expenditures, Sierra Club points to Company witness Moul's statement at hearing that FES **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the Plants.[625] The fact that Sierra Club attempts to paint this statement as somehow reflecting a perverse incentive created by the proposed transaction is simply baffling. Of course FES has an incentive to invest in the Plants; it will be running those same plants after the 8-year term of the agreement.[626] FES also faces a risk of having to pay substantial damages to the Companies for outages lasting longer than 180 days or forced outages that could not have been avoided by an exercise of Good Utility Practice. Indeed, if an outage of up to 180 days is not excused, or if an outage lasts more than 180 days, FES must provide the Companies with replacement Capacity, Energy, Ancillary Services and

[622] Hearing Tr. Vol. XIV, pp. 3021-23 (Ruberto Recross).

[623] Company Ex. 156, Section 12. *See also* Hearing Tr. Vol. I, p. 51 (Mikkelsen Cross); Hearing Tr. Vol. XXI, p. 4065 (Chriss Cross).

[624] Company Ex. 156, Section 8. *See also* Hearing Tr. Vol. I, p. 51 (Mikkelsen Cross); Hearing Tr. Vol. XIII, pp. 2298-99 (Moul Cross).

[625] Sierra Club Brief, p. 53.

[626] *See* Hearing Tr. Vol. XI (Confidential), p. 2461 (Moul Cross).

Environmental Attributes, or the financial equivalent thereof, for such remaining unavailability period.[627] Thus, FES has continuing financial incentives in ensuring the reliable operation of the Plants.

Arguments that there are incentives that might cause FES to over-invest[628] are also wrong. As an elementary matter, FES has to pay all costs up front.[629] As explained by Company witness Ruberto:

> Once the [8] years is up . . . FES continues to be responsible for the balance of [depreciation costs]. So since they [the Companies and FES] have a lot of interest in reducing expenses, there is a cooperative arrangement where we are both equally motivated to minimize expenses while continuing with the reliable operation of the unit.[630]

Sierra Club's own witness admitted that, with respect to capital expenditures, if there were costs that would be incurred or depreciation left unrecovered after the term of the PPA, FES would be responsible for such costs.[631] Additionally, and as demonstrated above, the costs passed through Rider RRS must satisfy Commission review, which encourages the Companies to remain actively engaged in the scrutiny of planned capital expenditures. Simply put, FES and the Companies have every incentive to work cooperatively to make only the necessary investments to ensure the reliable operation of the Plants.

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[627] Company Ex. 156, Section 8; Hearing Tr. Vol. XI, pp. 2333-34 (Moul Cross); Hearing Tr. Vol. XIV, p. 3003 (Ruberto Redirect). It should also be noted that even during an excused outage lasting fewer than 180 days, the Companies would not be paying for the cost of fuel, which constitutes a significant majority of the variable operating costs at the Sammis plant. Hearing Tr. Vol. IX (Confidential), p. 1998 (Lisowski Cross) (agreeing that [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]; Hearing Tr. Vol. XXXII, p. 6543 (Moul Cross) (stating that the vast majority of variable operating costs at Sammis is fuel).

[628] Sierra Club Brief, p. 53.

[629] Company Ex. 156, Section 12 ("Seller shall perform, or cause to be performed, Capital Expenditures Work related to [the Plants.]"); Hearing Tr. Vol. XIII, pp. 2780-81 (Ruberto Cross) (describing the capital expenditures process).

[630] Hearing Tr. Vol. XII, p. 2781 (Ruberto Cross).

[631] Hearing Tr. Vol. XXXI, pp. 6421-22 (Comings Cross).

Sierra Club's broad assertion that decisions regarding capital expenditures "are exempt from the 'good utility practice' requirement" is also misplaced.[632] To support its claim, Sierra Club points to the exclusion of "Capital Expenditures Work" from the definition of "Operating Work" in the Final Term Sheet.[633] But once a capital expenditure project goes into use, it becomes "Operating Work." As explained by Company witness Ruberto, the Good Utility Practice requirement applies to the Companies' obligation to make payments for depreciation once a capital investment has been put into use and becomes "Operating Work" because the Final Term Sheet defines that term as "operation, maintenance, ***use***, repair or retirement of the Facility[.]"[634] The provisions of the Final Term Sheet notwithstanding, capital expenditure costs will be subject to the Commission's prudence review, and any imprudently incurred costs will be disallowed. Sierra Club's attempt to argue that customers will be exposed to the costs of unreasonable capital expenditure decisions is therefore unavailing.

In contrast to Sierra Club, other intervenors position themselves at the opposite extreme by arguing that FES is, in fact, incentivized *not* to invest in the Plants. The IMM argues that if the Economic Stability Program is approved, FES will lack sufficient incentive to manage the Plants' performance because customers, not shareholders, will bear the risk of performance penalties.[635] Dynegy echoes this claim.[636] As demonstrated above, these claims are detached from FES's rational economic interests and fail to account for the significant obligations

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[632] Sierra Club Brief, p. 52. Sierra Club also argues that the "crucial question" of how a dispute between the Companies and FES concerning whether Good Utility Practice was followed will be resolved has been left unanswered. Sierra Club Brief, p. 50. For the Commission's purposes, the dispute resolution process is not relevant, let alone "crucial." Indeed, Sierra Club never suggests how it is otherwise. Regardless of whether costs included in the Rider RRS calculation are considered by the Companies and FES to be a result of Good Utility Practice, all those costs remain subject to the Commission's independent review.

[633] Sierra Club Brief, p. 52.

[634] Hearing Tr. Vol. XIV, pp. 3000-01, 3002-03 (Ruberto Redirect); Company Ex. 156, p. 15 (emphasis added).

[635] IMM Brief, p. 5.

[636] Dynegy Brief, p. 19.

imposed on FES by the Final Term Sheet. FES has an abiding interest in the reliability of the Plants because it will take back title to them after the term of the proposed transaction. This fact alone is enough to compel FES to make the necessary investment in the Plants, in accordance with Good Utility Practice. FES, however, also faces the additional risk of substantial financial liability if the Plants experience an outage of 180 days or more or if a shorter outage could have been prevented by the exercise of Good Utility Practice. In short, these intervenors' academic allegations find no support in reality.

In a blatant internal contradiction, EPSA/P3 make arguments at both extremes in the same brief. EPSA/P3 first contend that FES has "minimal incentives to make additional investments in capital" because it will not be at risk of CP penalties during the term of Rider RRS.[637] Ten pages later, EPSA/P3 allege unequivocally that "Rider RRS incentivizes FES to overinvest in capital."[638] This contradiction renders EPSA/P3's arguments in this respect of no persuasive value.

EPSA/P3's internal inconsistencies aside, the Commission is left with, on one hand, Sierra Club, OCC/NOAC and OMAEG arguing that FES has an incentive to over-invest. And on the other, the IMM and Dynegy arguing that FES has no incentive to ensure that the Plants do not underperform. Neither of these arguments is correct. In conjunction with the fact that FES will protect its economic interests by making necessary investments in the Plants, the Final Term Sheet, as explained, balances the tension in the intervenors' contradictory positions by imposing the Good Utility Practice obligation upon FES.

[637] EPSA/P3 Brief, pp. 25-26.

[638] EPSA/P3 Brief, p. 36.

e. **The Companies and FES have committed to extensive information sharing.**

As the Companies' Initial Brief demonstrated, the Companies have agreed to a rigorous review process and full information sharing – including the sharing of information on generating units in the FES fleet that are not included in the proposed transaction.[639] Nevertheless, certain intervenors still express concern that the Staff review will be only "financial" (i.e., only the costs incurred by the Plants will be reviewed) and not "substantive" (allowing Staff to review decisions made at the Plants).[640] OCC/NOAC argue that there are no criteria for the review.[641] These concerns are illusory.

As Company witness Mikkelsen testified, "the Commission has full authority to review the costs and ***the underlying basis for the incurring of those costs*** for reasonableness such that they can ultimately make a determination in its judgment based on the facts and circumstances known at the time the costs were incurred."[642] The audit shall confirm that the costs and revenues proposed for inclusion in Rider RRS are not unreasonable. Further, the Commission's review will be the same as the historic test the Commission employed when the plants were regulated.[643] In fact, when asked by Examiner Price if there would be any differences from the way the Staff normally conducted a prudence review, Ms. Mikkelsen unequivocally testified that there would not be any differences. [644] Some parties obviously understood that this was the case. For example, at hearing, Wal-Mart witness Chriss acknowledged there is no limit on Staff's

[639] Companies' Initial Brief, pp. 73-76.

[640] *See, e.g.*, Wal-Mart Brief, p. 8.

[641] OCC/NOAC Brief, p. 82.

[642] Hearing Tr. Vol. XXXVI, p. 7701 (Mikkelsen Cross).

[643] Hearing Tr. Vol. I, pp. 77-78 (Mikkelsen Cross).

[644] Hearing Tr. Vol. I, p. 78 (Mikkelsen Cross).

ability to review going-forward costs that are incurred.[645] Concerns, such as NOPEC's, that the proposal lacks traditional regulatory oversight[646] are therefore unfounded.

Given that the process outlined by the Companies would be no different than the process used by the Staff and the Commission for countless rider audit proceedings, the criticisms made by some border on the bizarre. For example, EPSA/P3 worry that the Companies might have the ability to challenge the findings of such a proceeding.[647] But this is the right that every utility has regarding adverse determinations by the Commission in rider audit cases.[648] OCC/NOAC's concerns about the "chilling effect" a disallowance could have on the Companies is similarly odd as that same concern would apply to every Commission audit proceeding.[649]

Wal-Mart argues it is not clear whether the review process would be open to all intervenors.[650] The contrary is true. Ms. Mikkelsen explained at hearing that after the Staff has filed its report on its review of the reasonableness of the actual costs (excluding Legacy Cost Components)[651] and actual market revenues, intervenors would have the opportunity, subject to Commission approval, to participate in the proceeding (including the opportunity to submit data requests to the Companies).[652] Accordingly, the review process adequately ensures an appropriate level of intervenor participation.

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645 Hearing Tr. Vol. XXI, p. 4063 (Chriss Cross).

646 NOPEC Brief, p. 43.

647 EPSA/P3 Brief, pp. 27-28.

648 R.C. 4903.13.

649 OCC/NOAC Brief, p. 132.

650 Wal-Mart Brief, p. 9.

651 Mr. Chriss agreed on cross-examination that the Companies have produced the details of Legacy Cost Components to the intervenors in this proceeding, and that the parties had the opportunity in the hearing to ask questions about Legacy Cost Components. Hearing Tr. Vol. XXI, pp. 4061-4062 (Chriss Cross).

652 Hearing Tr. Vol. I, p. 82 (Mikkelsen Cross).

Many of the same intervenors express concern that FES will not provide the information requested. Indeed, some complain that there is no "documentation" of FES's commitment.[653] The record is otherwise. The Final Term Sheet requires FES to cooperate in this process, by providing that "[FES] shall reasonably and timely provide all data and information requested by [the Companies]: (i) to respond to a Governmental Authority request for information; (ii) to prepare for and make other regulatory filings; and (iii) as required by law with respect to [the Companies]."[654] Further, even without the Final Term Sheet's provision, these parties' comments ignore the commitment made by the Companies in the Third Supplemental Stipulation regarding full information sharing not only for the generating units included in the proposed transaction but for the entire FES fleet.[655]

CMSD expressed a similar concern that the Companies can't make that commitment on behalf of FES.[656] This ignores the fact that "the companies made this commitment on behalf of FES after checking with the FES business unit management to assure that they could make that commitment on behalf of FES."[657] Further, as Ms. Mikkelsen testified, if there was an FES dispute about producing requested information, the Companies would "bear the risk associated with the failure to produce that information." [658]

The Third Supplemental Stipulation added a commitment that FES fleet information will be provided pursuant to a reasonable Staff request.[659] ELPC claims that the commitment is

[653] NOPEC Brief, p. 44; OMAEG Brief, pp. 48-49.

[654] Company Ex. 156, Section 18.

[655] Third Supp. Stip., Section 16.

[656] CMSD Brief, pp. 41-42.

[657] Hearing Tr Vol XXXVI, pp. 7519-20 (Mikkelsen Cross).

[658] Hearing Tr. Vol. I, p. 84 (Mikkelsen Cross).

[659] Company Ex. 135, p. 8.

insufficient because it provides no detail on what would constitute a reasonable request.[660] However, the Third Supplemental Stipulation need not contain this degree of detail. As Ms. Mikkelsen explained at hearing, if the Companies and Staff were not able to resolve any issues with respect to reasonableness, then the ultimate disposition would be made by the Commission.[661]

OCC/NOAC further assert that intervenors should also have access to FES fleet information provided to Staff pursuant to this commitment.[662] The Third Supplemental Stipulation, however, recognizes the sensitivity associated with providing FES's fleet information and accordingly required:

> Staff shall treat any and all such information, regardless of its content, as if it is highly sensitive, proprietary, trade secret information, and Critical Energy Infrastructure Information ["CEII"]. In addition, as permitted by law, such information shall not be subject to a public information request and shall be protected indefinitely.[663]

Because information contemplated by this commitment could be highly sensitive, proprietary, trade secret information, and CEII protected by federal law, the protection provided by the Third Supplemental Stipulation is appropriate.

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[660] Rábago Direct, p. 11. Thus, questions raised about whether the Staff would be able to see, for example, all of FES' "purchasing expenses" (*see* OCC/NOAC Brief, p. 132) or whether the Commission lacks jurisdiction to require FES to produce anything (CMSD Brief, p. 42) are irrelevant. The process outlined in the record here envisions the Staff and the Companies working together to resolve any differences about what should be produced. Any remaining dispute about what should be produced would be resolved by the Commission. As noted, the Companies would bear the burden of failing to produce material deemed discoverable by the Commission. Oddly, EPSA/P3 voices a concern that the Companies could somehow challenge such a decision about production in "court." EPSA/P3 Brief, p. 27. Assuming that this refers to some type of interlocutory relief, EPSA/P3 provides no authority or explanation as to how that could happen given that only the Ohio Supreme Court has the authority to review Commission orders and only final ones at that. R.C. 4903.13.

[661] Hearing Tr. Vol. XXXVI, p. 7519 (Mikkelsen Cross).

[662] OCC/NOAC Brief, p. 83.

[663] Company Ex. 135, p. 8.

Exelon and NOPEC object because OVEC information will not be shared in the same manner as information for Davis-Besse and Sammis.[664] But, there is no need for the same information sharing requirements for OVEC as for the other units because FES is not the entity responsible for making investment decisions at OVEC. Therefore neither the Companies nor FES can agree to provide the same level of detail as it can provide for the other units.

NOPEC, OMA, Exelon and Sierra Club erroneously claim that the Companies' proposal does not allow for the Commission's review of legacy costs included in Rider RRS or that there is no opportunity to review the prudence of legacy costs.[665] RESA views legacy costs as a loophole in the oversight process.[666] This is simply not true. As Ms. Mikkelsen testified, "the legacy cost components included in future filings would be eligible for the first review process…as well as in the second review what I would characterize as an accounting review to be sure that the costs that are charged do tie out to the seller's books and records." [667] Regarding the prudence review of legacy costs, the Companies have stated from the onset that the opportunity to review and challenge legacy costs is in this proceeding.[668] Because no party raised a concern regarding the prudence of any of the legacy costs[669] during this proceeding does not mean there was no opportunity for the review or that they should be reviewed again in future

[664] Exelon Brief, pp. 51-52; NOPEC Brief, p. 44.

[665] NOPEC Brief, p. 43; OMAEG Brief, p .46; Exelon Brief, p. 51; Sierra Club Brief, p. 60.

[666] RESA Brief, p. 33.

[667] Hearing Tr. Vol. I, p. 79 (Mikkelsen Cross).

[668] Hearing Tr. Vol I, p. 162 (Mikkelsen Cross).

[669] The IMM erroneously concludes that "all historical costs incurred at the RRS Assets prior to the proposed transfer" would become the responsibility of ratepayers (IMM Brief p. 2). Legacy costs are costs arising *during the term of Rider RRS* from decisions or commitments made or contracts entered into prior to December 31, 2014. Mikkelsen Direct, p. 14.

audits. Legacy costs components should properly be excluded from challenge in future audit proceedings.[670]

f. **The negotiated contract price ROE is appropriate.**

The initial proposed 11.15% return on equity ("ROE") was appropriate and consistent with the ROE the Commission approved in AEP Ohio's recent capacity proceeding, Case 10-2929-EL-UNC.[671] Prior to the Third Supplemental Stipulation, the FES and EDU teams negotiated a lowered ROE of 10.38%.[672] OCC/NOAC argue that there isn't any record support supporting an ROE of 10.38%.[673] This is incorrect: Company witness Staub offered extensive testimony supporting an ROE of 11.15%. Two different intervenor witnesses also provided recommendations. As a result, there is ample record evidence supporting an ROE of 10.38%.

No intervenor filed testimony directly contesting the 10.38%. However, during the initial phase of the hearing witnesses for both Wal-Mart and OCC/NOAC recommended lower ROE's than were ultimately adopted. Wal-Mart witness Chriss did not provide a point ROE recommendation,[674] but identified a national average ROE for vertically integrated utilities of 10.02%.[675] OCC witness Woolridge recommended an ROE of 8.7%.[676] Staff testified that an ROE of 9.6% was reasonable for a regulated utility, even before addressing the different risk

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[670] Mikkelsen Direct, p. 15.

[671] Staub Direct, pp. 3-5; Hearing Tr. Vol. X, p. 2064 (Staub Cross); Hearing Tr. Vol. XXII, p. 4716 (Woolridge Cross). *See also, In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC, Opinion and Order, p. 34 (July 2, 2012) ("[W]ith respect to the appropriate return on equity, we find that AEP-Ohio's recommendation of 11.15 percent is reasonable and should be adopted.").

[672] Company Ex. 156 (Third Supplemental Stipulation).

[673] OCC/NOAC Brief, p. 151.

[674] Hearing Tr. Vol. XXI, p. 4066 (Chriss Cross).

[675] Chriss Direct, p. 12.

[676] Woolridge Direct, p. 5.

profiles between regulated and unregulated operations.[677] All of the ROE's recommended by these witnesses they fail to account for the hypothetical capital structure used by the transaction, which lowers the effective ROE to FES to 9.03%. Moreover, the intervenor testimony fails to address several important issues relating to the appropriate ROE for these facilities.

(i) The hypothetical capital structure decreases the effective ROE to 9.03%

As demonstrated in the Companies' Initial Brief,[678] FES's actual capital structure is 65% equity and 35% debt. The Companies negotiated a hypothetical 50/50 capital structure in determining the weighted average cost of capital.[679] This reduced the negotiated 10.38% ROE from the Third Supplemental Stipulation to only 9.03%.[680]

A true ROE of 9.03% is well below the (regulated vertically integrated utility) national average of 10.02%, and is barely above the flawed 8.7% ROE proposed by OCC/NOAC. As the true ROE to FES under the Final Term Sheet is below the 9.36% average of the intervenor witnesses' recommendations and the 9.6% recommended by Staff there can be no doubt the ROE in the Final Term Sheet is appropriate.

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[677] Hearing Tr. Vol. XXX, p. 6301 (Choueiki Cross).

[678] Companies' Initial Brief, p. 48.

[679] Staub Direct, pp. 10-11; Hearing Tr. Vol. 1, pp. 35-36 (Mikkelsen Cross); Hearing Tr. Vol. XVIII, pp. 3621-22 (Savage Cross).

[680] As explained in the Mikkelsen November 30, 2015 Workpaper (Sierra Club Ex. 89), applying the negotiated ROE of 10.38% to FES's assumed 50/50 capital structure results in a weighted average cost of capital ("WACC") of 7.46%:
10.38% * 50% Hypothetical Equity + 4.54% Cost of Debt * 50% Hypothetical Debt = 7.46% WACC
Applying this 7.46% WACC to FES's actual capital structure of 65% Equity and 35% Debt (Staub Direct, p. 10) results in an effective ROE of 9.03%:
(7.46% WACC – (4.54% Cost of Debt * 35% Equity))/ 65% Equity = 9.03% ROE

(ii) The Intervenor ROE recommendations are flawed.

a) Mr. Woolridge's peer group had different capital structures, lines of business, and credit ratings than FES

OCC/NOAC argues that OCC witness Woolridge's ROE should be used for Rider RRS.[681] OCC witness Woolridge's analysis is woefully inaccurate. Dr. Woolridge provided only a short-term ROE in a time of extremely low interest rates which failed to acknowledge the 8 year rate lock negotiated by the Companies. Dr. Woolridge also admitted that the proxy group should be similar to the business being examined, both in risk profile and line of business.[682] Despite that admission, his peer group was dissimilar from FES in almost every way.

Dr. Woolridge admitted that today's interest rates are at historic lows. "They're still relatively low, yes, near all-time low."[683] Dr. Woolridge then identified seven separate reasons why those rates could rise in the future.[684] Despite those admissions, Dr. Woolridge failed to take into account that the ROE is fixed in the agreement for eight years, and did not include any term premium in his analysis.[685] This omission is important because Dr. Woolridge admitted that rising interest rates would affect the cost of capital, and fixing the ROE would benefit customers by removing the risk of rate increases.[686]

Dr. Woolridge also objected because he disagreed with the 11.15% ROE used by the Commission in the AEP Ohio capacity case, using the same logic as he applies in his testimony

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[681] OCC/NOAC Brief, p. 151.

[682] Hearing Tr. Vol. XXIII, pp. 4712-13 (Wooldridge Cross).

[683] Hearing Tr. Vol. XXIII, p. 4720.

[684] Hearing Tr. Vol. XXIII, pp. 4713-15.

[685] Hearing Tr. Vol. XXIII, p. 4726.

[686] Hearing Tr. Vol. XXIII, p. 4721.

in this proceeding.[687] Incredibly, he claims that the AEP capacity case decision does not reflect today's market, despite admitting that interest rates were at historic lows in 2012 when the AEP capacity decision was issued.[688] Just as the Commission rejected those positions in the AEP Ohio case, the Commission should reject those positions here.

Dr. Woolridge's peer group was severely flawed, most likely because Dr. Woolridge has never calculated a return on equity for a merchant generator before.[689] Dr. Woolridge admits that if companies are lower rated they are riskier than higher rated companies.[690] Despite this, his peer group included 7 BBB+ utilities, 11 BBB utilities, and only 2 BBB- utilities.[691] At BBB-, FirstEnergy Corp. (the entity he examined instead of FES) had the lowest credit rating and return on equity of any entity in his peer group.[692] Dr. Woolridge included no merchant generators in his peer group since his source document included only utilities, thereby artificially limiting the number of possible peer companies.[693] Every company included by Dr. Woolridge receives at least 50% of its revenue from regulated operations, making them substantially different from a merchant generator like FES.[694] Despite admitting that FirstEnergy Corp. was weaker and more risky than the other companies in his "utilities only" peer group, Dr. Woolridge

[687] Hearing Tr. Vol. XXIII, p. 4717 (Woolridge Cross).

[688] Hearing Tr. Vol. XXIII, p. 4719 (Woolridge Cross).

[689] Hearing Tr. Vol. XXIII, p. 4730 (Woolridge Cross).

[690] Hearing Tr. Vol. XXIII, p. 4733 (Woolridge Cross).

[691] Hearing Tr. Vol. XXIII, p. 4734 (Woolridge Cross).

[692] Hearing Tr. Vol. XXIII, p. 4736 (Woolridge Cross).

[693] Hearing Tr. Vol. XXIII, p. 4736 (Woolridge Cross).

[694] Hearing Tr. Vol. XXIII, p. 4737 (Woolridge Cross).

made no adjustment to his analysis to reflect those factors.[695] Dr. Woolridge also made no adjustment to reflect that he examined the risk factors for FirstEnergy Corp. rather than FES. [696]

Dr. Woolridge also attempted to defend his abnormally low ROE by pointing to the historic returns on equity for FES for the last few years.[697] At hearing even Dr. Woolridge acknowledged this was irrelevant. Dr. Woolridge admitted that historic returns on equity has no bearing on what a future regulatory return on equity should be.[698]

Dr. Woolridge recommended that the Commission use the FirstEnergy Corp. capital structure instead of the FES capital structure or the hypothetical capital structure negotiated by the Companies.[699] Despite this recommendation, Dr. Woolridge still used the FES actual cost of debt in his analysis. [700] This is significant, because if the FES actual equity percentage were deceased Dr. Woolridge admitted that FES's cost of debt would increase.

> Q. So, Doctor, holding all else constant, you would agree if FirstEnergy Solutions debt was increased from 35 percent to 55 percent, then the expected cost of debt would increase, correct?
>
> A. Yes. I will agree in the sense that if they used more debt, their financial risk would go up and cost of debt would go up, all else equal.
>
> Q. Because holding all else equal, as equity decreases, the relative risk of the firm would increase.
>
> A. Yes.[701]

[695] Hearing Tr. Vol. XXIII, p. 4737 (Woolridge Cross).

[696] Hearing Tr. Vol. XXIII, p. 4737 (Woolridge Cross).

[697] Woolridge Direct, p. 5.

[698] Hearing Tr. Vol. XXIII, p. 4728 (Woolridge Cross).

[699] Hearing Tr. Vol. XXIII, p. 4739 (Woolridge Cross).

[700] Hearing Tr. Vol. XXIII, p. 4739-40 (Woolridge Cross).

[701] Hearing Tr. Vol. XXIII, p. 4741 (Woolridge Cross).

Dr. Woolridge did not take the impact of the 20% change to the FES capital structure he made into account when determining the appropriate return on equity.[702]

Dr. Woolridge's testimony is flawed for his failure to include term premium to reflect the 8 year rate lock, failure to consider the Commission precedent from the AEP Ohio capacity case during a historically low interest rate period, misleading use of historic earned ROE in his testimony, flawed peer group, and unsupported adjusted capital structure. Despite these errors, Dr. Woolridge still recommended a ROE of 8.7%, very similar to the actual negotiated ROE to FES of 9.03%.

b) Mr. Chriss examined vertically integrated utilities which are less risky than merchant generation like FES.

Wal-Mart argues that its recommended ROE should be adopted.[703] Wal-Mart Witness Chriss identified a national average ROE for vertically integrated utilities of 10.02%.[704] Mr. Chriss also examined other types of ROE's, but he correctly testified the vertically integrated ROE's are most analogous to this proceeding.[705]

Mr. Chriss' recommendation is flawed because Mr. Chriss looked at vertically integrated utilities as opposed to merchant generators like FES. As merchant generators like FES have more risk, and thus a higher necessary ROE, than vertically integrated utilities, Mr. Chriss' comparison is not appropriate since it failed to use a correct peer group.

Mr. Chriss' recommendation is also flawed because his national average was developed by looking at point ROE's awarded by state Commissions. Those proceedings differed from this one because they did not include a rate lock. Like Dr. Woolridge, Mr. Chriss did not modify this

[702] Hearing Tr. Vol. XXIII, p. 4741 (Woolridge Cross).

[703] Wal-Mart Brief, p. 5.

[704] Chriss Direct, p. 12.

[705] Hearing Tr. Vol. XXI, p. 4071 (Chriss Cross).

peer group to reflect any term premium showing the eight year rate lock.[706] Mr. Chriss agreed that interest rates could rise in the future, that this could cause costs of capital to increase, and that there was logic to using a term premium when examining Rider RRS.[707]

Mr. Chriss also did not compare the credit ratings of FES to the regulated vertically integrated utilities he examined.[708] As FES has a credit rating of BBB-, it is likely lower rated than the regulated utilities examined by Mr. Chriss. Mr. Chriss should have adjusted his analysis to reflect FES's credit rating as compared to the peer group.

Though much more fair and balanced than the artificially decreased ROE estimate sponsored by Dr. Woolridge, Mr. Chriss' national average of 10.02% is nevertheless overly conservative because it looks at vertically integrated utilities instead of merchant generation, does not incorporate a term premium, and fails to take into account FES's credit rating. Even with those oversights, Mr. Chriss' 10.02% average is well above the 9.03% ROE that FES will earn under the hypothetical capital structure. Thus, Mr. Chriss' testimony is additional evidence of the reasonableness of the ROE negotiated in the Third Supplemental Stipulation.

c) Mr. Staub's evidence also supports the proposed ROE.

Mr. Staub's testimony provides extensive additional evidence in support of the ROE. Mr. Staub examined the analogous AEP capacity decision, the difference between that award and AEP Ohio's distribution ROE's, the most recent ROE approved for the Companies of 10.5%, the 13.3% ROE average for merchant generators, and the appropriate term premium to reflect a rate lock. The extensive evidence provided by Mr. Staub justified the ROE of 11.15%, so the

[706] Hearing Tr. Vol. XXI, pp. 4067, 4072 (Chriss Cross).

[707] Hearing Tr. Vol. XXI, p. 4074 (Chriss Cross).

[708] Hearing Tr. Vol. XXI, p. 4069 (Chriss Cross).

hypothetical capital structure true ROE of 9.03% is certainly supported by extensive record evidence.

g. The proposed transaction was negotiated in a good faith process and produced a result superior to any potential competitive procurement.

(i) RRS should not be competitively bid because the negotiation process is better than a competitive procurement.

Cleveland, Dynegy, ELPC, Exelon, Sierra Club and OCC/NOAC argue that the Companies should have engaged in some sort of "competitive process" instead of negotiating the proposed transaction with FES.[709] These arguments fail for two basic reasons. First, given the extensive due diligence efforts undertaken by the EDU Team on behalf of the Companies and the good-faith arm's length negotiations between the Companies and FES, no such "competitive process" was necessary. Through these negotiations, the Companies were able to arrive at a framework whereby they could offer a beneficial, rate-stabilizing hedge to their customers.[710] This hedge is worth approximately $561 million over the eight-year term of ESP IV.

Second, intervenors simply ignore, or fail to understand, that the Economic Stability Program also offers numerous other unique benefits. The Economic Stability Program enhances the reliability of Ohio's distribution grid, supports economic development resulting from retail rate stability, supports economic development resulting from retail rate stability, provides for environmental compliance benefits, and avoids the need for costly transmission system upgrades that would otherwise prove necessary. No intervenor proffered any evidence that a "competitive process" would yield these additional benefits to the Companies' customers.

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[709] *See* Exelon Brief, pp. 74-75; Sierra Club Brief, p. 73; Dynegy Brief, pp. 19-20; ELPC Brief, p. 26-34; Cleveland Brief, pp. 8-9; OCC/NOAC Brief, p. 136.

[710] Hearing Tr. Vol. XIII, p. 2788 (Ruberto Cross).

The proposed transaction between the Companies and FES was the subject of extensive due diligence and negotiations conducted at arm's length.[711] After being approached by FES regarding the proposed transaction, the Companies assembled a multi-disciplinary team with experience in regulated generation, transmission, legal, rates, and accounting, (*i.e.*, the EDU Team).[712] The work charge adopted by the EDU Team, as explained by its leader Company witness Ruberto, was: if the EDU Team found that the proposed transaction had value then the EDU Team was charged with negotiating terms that were, first and foremost, beneficial for customers.[713]

By any measure, the EDU Team due diligence process engaged in by the EDU Team to determine whether the proposed transaction could benefit customers was extensive.[714] As part of this process, the EDU Team obtained cost information and operational data on the Plants and the OVEC interest from FES, verified the levels of projected costs, and benchmarked those costs against industry data.[715] The Companies retained witness Rose, as noted, a nationally recognized price forecast expert from ICF International, to forecast market prices.[716] Mr. Rose's projections included energy, capacity and carbon prices, as well as Sammis fuel costs. Mr. Rose's projections and FES's and OVEC's projected costs were used to project the Plants' and the OVEC interest's output, costs and market revenues.[717] The EDU Team also examined the last five years of historical data and compared it to public data from 2013 FERC Form 1 reports for

[711] Hearing Tr. Vol. XIII, p. 2788 (Ruberto Cross).

[712] Hearing Tr. Vol. XIII, p. 2766 (Ruberto Cross); Sierra Club Ex. 52 (Response to OCC Set 1-INT-19).

[713] Ruberto Direct, p. 4.

[714] Ruberto Direct, pp. 4-5; Hearing Tr. Vol. XIII, pp. 2761; 2762; 2767-68; 2787-88; 2885 (Ruberto Cross).

[715] Ruberto Direct, p. 5; Hearing Tr. Vol. XIII, pp. 2887-88 (Ruberto Cross); Sierra Club Ex. 37C.

[716] Hearing Tr. Vol. XIII, p. 2791 (Ruberto Cross).

[717] Ruberto Direct, p. 5; Hearing Tr. Vol. XIII, p. 2764 (Ruberto Cross).

comparable coal and nuclear plants.[718] The EDU Team further toured Sammis and Davis-Besse to review plant operations, met with plant personnel, and observed the condition of the Plants.[719] Additionally, the EDU Team requested the Companies' transmission planning group to perform a study to identify impacts on the transmission system if the Plants retired, and the costs of transmission upgrades necessary to remedy violations.[720] The EDU Team also consulted Company witness Sarah Murley for an analysis of the Plants' local and regional economic impacts.[721]

Given this extensive due diligence, the EDU Team concluded that the proposed transaction could significantly benefit the Companies' customers. The EDU Team then entered into negotiations with FES to attempt to arrive at terms that maximized those benefits. In doing so, the EDU Team evaluated the value and risks associated with various term lengths.[722] Because costs are forecasted to exceed revenues in the early years of the proposed transaction, the Companies made sure to negotiate a term long enough to capture sufficient value for customers in the later years when revenues are forecasted to exceed costs.[723]

Notably, as discussed above, the Companies negotiated a very favorable ROE for recovery of capital costs that is fixed for the entire term of the proposed transaction. Prior to the finalization of the Third Supplemental Stipulation, the Companies negotiated an effective ROE

[718] Hearing Tr. Vol. XIII, pp. 2773-74 (Ruberto Cross).

[719] Ruberto Direct, p. 4; Hearing Tr. Vol. XIV, pp. 2988-90 (Ruberto Cross).

[720] Hearing Tr. Vol. XIII, pp. 2791-93 (Ruberto Cross).

[721] Hearing Tr. Vol. XIII, p. 2791 (Ruberto Cross).

[722] Ruberto Direct, p. 5; Hearing Tr. Vol. XIII, pp. 2767-68; 2885 (Ruberto Cross).

[723] Ruberto Direct, p. 5.

of 9.03%.[724] There is no question that an effective ROE of 9.03% is reasonable Further, Exelon obtained relief for its Ginna nuclear facility in New York, receiving over $17 million in monthly payments calculated using an ROE of 10.7%.[725] Exelon witness Campbell claims in his direct testimony that the Ginna arrangement was further "complimented by an RFP process."[726] Given that the Companies have negotiated an effective ROE of 9.03%, *approximately 15% lower than the Ginna ROE*, Exelon simply cannot claim that any alleged "competitive process" would have produced a better outcome here for the Companies' customers.

Further, the Companies negotiated numerous protections for customers. The Companies obtained the all-important right to market (including dispatch) all of the output of the Plants and FES's OVEC entities. Further, as admitted by OCC/NOPEC witness Kahal[727] and Staff witness Choueiki,[728] the Companies have the right to audit the costs charged by FES to the Companies and FES must consult the Companies regarding capital projects.[729] Further, as admitted by Cleveland witness Cole,[730] Wal-Mart witness Chriss,[731] EPSA/P3 witness Kalt,[732] and Sierra

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[724] As explained in the Mikkelsen November 30, 2015 Workpaper (Sierra Club Ex. 89), applying the negotiated ROE of 10.38% to FES's assumed 50/50 capital structure results in a weighted average cost of capital ("WACC") of 7.46%:

10.38% * 50% Hypothetical Equity + 4.54% Cost of Debt * 50% Hypothetical Debt = 7.46% WACC

Applying this 7.46% WACC to FES's actual capital structure of 65% Equity and 35% Debt (Staub Direct, p. 10) results in an effective ROE of 9.03%:

(7.46% WACC – (4.54% Cost of Debt * 35% Equity))/ 65% Equity = 9.03% ROE

[725] Hearing Tr. Vol. XXVI, pp. 5231-32 (Campbell Cross).

[726] Campbell Direct, p. 18.

[727] Hearing Tr. Vol. XXIV, p. 4879 (Kahal Cross) (admitting to audit rights and consultation on capital projects).

[728] Hearing Tr. Vol. XXX, p. 6301 (Choueiki Cross) (admitting to audit rights and consultation on capital projects)).

[729] Company Ex. 156 Section 18; Ruberto Direct, p. 9; Hearing Tr. Vol. XIII, pp. 2878; 2879 (Ruberto Cross).

[730] Hearing Tr. Vol. XXI, pp. 4233-34 (Cole Cross).

[731] Hearing Tr. Vol. XXI, p. 4066 (Chriss Cross).

[732] Hearing Tr. Vol. XVIII, p. 5620 (Kalt Cross).

Club witness Comings,[733] FES's Operating Work at the Plants is required to be governed by Good Utility Practice[734] and the Companies will not pay for operating work in the contract price that is not in conformance with Good Utility Practice.[735] The Companies further have the authority to review and comment upon FES's capital improvements plan and scheduled outage program, which, as Staff witness Choueiki admitted,[736] should benefit customers on both the cost and revenue sides of this transaction.[737] Moreover, as admitted to by both Mr. Chriss,[738] and Dr. Kalt,[739] customers would be under no obligation to pay approved capital costs after the end of the PPA, even if such costs were amortized beyond the term of the PPA.

Simply put, based on extensive due diligence, the Companies negotiated a competitive outcome for their customers, including, by any measure, a reasonable effective ROE of 9.03%, and extensive customer protections in the form of audit rights and Good Utility Practice requirements. As a direct result of the Companies arm's-length negotiation efforts, the Companies' customers are forecasted to receive a $561 million hedge against retail rate price volatility over the term of Stipulated ESP IV. As such, OCC/NOAC's claim that the Companies should have had a "independent third party" review the proposed transaction is meritless.[740] In addition, Intervenors' briefs contain no evidence, and none was introduced at hearing, that any

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[733] Hearing Tr. Vol. XXXI, p. 6418 (Comings Cross).

[734] Company Ex. 156 Section 11; Ruberto Direct, p. 9; Hearing Tr. Vol. XIII, pp. 2850; 2892 (Ruberto Cross).

[735] Hearing Tr. Vol. XIV, pp. 3000–01 (Ruberto Cross).

[736] Hearing Tr. Vol. XXX, p. 6301 (Choueiki Cross).

[737] Company Ex. 156 Section 12; Ruberto Direct, p. 9; Hearing Tr. Vol. XIII, pp. 2779-82 (Ruberto Cross); Hearing Tr. Vol. XXX, p. 6301 (Choueiki Cross). Further, customers would be under no obligation to pay approved capital costs after the end of the PPA, even if such costs were amortized beyond the term of the PPA. Hearing Tr. Vol. XXI, pp. 4064-65 (Chriss Cross); Hearing Tr. Vol. XXVIII, pp. 5620-21 (Kalt Cross).

[738] Hearing Tr. Vol. XXI, pp. 4064-65 (Chriss Cross)

[739] Hearing Tr. Vol. XXVIII, pp. 5620-21 (Kalt Cross).

[740] *See* OCC/NOAC Brief, p. 136.

such review, or any putative "competitive process," would have yielded more beneficial results for the Companies' customers.

In addition to a $561 million retail rate stability mechanism, the Economic Stability Program contains several other significant benefits for customers described at length in the Companies' Initial Brief.[741] No evidence has been produced that similar benefits would result from a "competitive process." Indeed, the evidence points in the opposite direction.

One of the many benefits of the Economic Stability Program is that it will provide significant reliability benefits to the Companies' customers.[742] No intervenor has come forth with any evidence that a "competitive process" would yield similar reliability benefits. The Economic Stability Program will ensure "the continued operation of baseload generating units that are fuel diverse with onsite fuel storage capabilities," thereby mitigating the effects of severe weather events like the Polar Vortex and enhancing the reliability of Ohio's distribution grid.[743] It is beyond dispute that such enhanced reliability benefits both customers and the public interest. Indeed, "the continued operation of baseload fuel diverse generating plants with onsite fuel storage capabilities that were built and designed to serve the load of the Companies would provide increased assurance for the reliability of the customers on the [C]ompanies' delivery system."[744]

If the Economic Stability Program is not approved and the Plants have to close, the loss of over 3,000 MW of baseload generation would have a negative impact on the stability of the

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[741] *See* Companies' Initial Brief, pp. 22-30, 55-73.

[742] Hearing Tr. Vol. XXI, pp. 4111-12 (Cole Cross).

[743] Hearing Tr. Vol. 1, p. 96 (Mikkelsen Cross); *see also* Hearing Tr. Vol. I, pp. 112, 154 (Mikkelsen Cross); Hearing Tr. Vol. IV, p. 874 (Strah Cross).

[744] Hearing Tr. Vol. III, pp. 635-36 (Mikkelsen Cross). *See also* Hearing Tr. Vol. III, p. 515 (Mikkelsen Cross); Hearing Tr. Vol. I, p. 96 (Mikkelsen Cross); Hearing Tr. Vol. XV, p. 3240 (Phillips Cross).

transmission system.[745] The Plants serve essential functions as part of the generation and transmission systems, and their retirement would cause violations of PJM's reliability standards.[746] This would necessitate substantial transmission upgrades. The record in this proceeding demonstrates that the costs of such upgrades would range between $436.5 million to $1.1 billion.[747] Unfortunately, a substantial portion of these costs would have to be borne in large part by customers.[748] According to a PJM TEAC Report, "[t]he cost of transmission upgrades to mitigate criteria violations caused by generation deactivation is allocated to load",[749] i.e., the Companies' customers. By keeping the Plants in service, the Economic Stability Program would obviate the need for such costly upgrades – a significant benefit that would not result from any alleged "competitive process" as favored by Cleveland, Dynegy, ELPC, Exelon, OCC/NOAC or Sierra Club.

Notwithstanding the above, the same intervenors criticize various aspects of the Companies due diligence efforts while simultaneously overlooking the unique attributes of the Plants and the benefits provided by the Economic Stability Program. These criticisms fall flat.

For example, ELPC and Sierra Club claim that the Companies, as part of their due diligence process, failed to engage in adequate benchmarking.[750] These claims fly in the face of the record evidence. As demonstrated in Sierra Club Exhibit 37C, the Companies engaged in an extensive benchmarking process. To benchmark costs, the EDU Team compared the 2013 and

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[745] *See, generally,* Direct Testimony of Gavin L. Cunningham, adopted by Rodney L. Phillips ("Phillips Direct")and Phillips Supp.

[746] Phillips Supp., pp. 4-6.

[747] Phillip Supp., pp. 6-8.

[748] Phillips Direct, p. 3; Ruberto Direct, p. 8; Phillips Supp., pp. 8, 10; Hearing Tr. Vol. XXV, p. 5152 (Lanzalotta Cross) (the Companies' customers would bear "some portion" of such costs).

[749] Sierra Club Ex. 60 (PJM TEAC Report), p. 2.

[750] ELPC Brief, p. 32; Sierra Club Brief, P. 73.

projected 2017 costs of Sammis and Davis-Besse to fifteen different comparable generation facilities.[751] The Companies compared Davis-Besse to ten different comparable nuclear plants and Sammis to five different comparable coal plants on a dollar per megawatt hour basis.[752] The EDU Team obtained this information from an objective and reliable source, the FERC 1 form cost information for the comparable facilities under consideration.[753]

As Company witness Ruberto explained:

> The EDU Team determined that the Sammis coal units are reasonably similar in generation cost to existing regulated coal-fired generation units. The level of outages costs, and projected expenditures are in line with what would be expected when compared to existing regulated fossil generation plants. Industry data was used to evaluate the cost of generation for the Davis-Besse nuclear plant. This review determined the level of outages, fuel costs, and labor cost to generate a MWh is reasonably comparable to other similar facilities. Based upon this analysis, we determined FES's forecasted cost levels are reasonable and consistent with generally accepted practices engaged in by a significant portion of the electric utility industry.[754]

Thus, based upon this information, the Companies concluded that the 2013 costs and projected 2017 costs of Davis-Besse and Sammis were in line with similarly situated generation facilities and therefore reasonable.[755] Before arriving at their final reasonableness determination, the EDU Team complemented this benchmarking information with further cost information obtained from FES regarding the Plants, including projected energy and capacity capabilities, outage rates, O&M and capital expenditures, taxes and planned outages.[756] Sierra Club nevertheless complains that the EDU Team only relied on regulated generation facilities when

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[751] Sierra Club Ex. 37C, pp. 1-3.

[752] Sierra Club Ex. 37C, pp. 2-3.

[753] Sierra Club Ex. 37C, p. 2.

[754] Ruberto Direct, p. 5.

[755] Sierra Club Ex. 37C, p. 2.

[756] Sierra Club Ex. 37C, pp. 2-3.

conducting its Sammis benchmarking (no such claim is raised in the case of Davis-Besse).[757] But Sierra Club overlooks the fact that this was the best information that was publicly available because merchant generators such as Dynegy and Exelon, for example, view such information as proprietary.[758]

ELPC also argues that the Companies should have considered alternative generation sources such as wind or natural gas-fired generation.[759] ELPC simply ignores the unique reliability attributes of the Plants. The Economic Stability Program will ensure "the continued operation of baseload generating units that are fuel diverse with onsite fuel storage capabilities," thereby mitigating the effects of severe weather events like the Polar Vortex and enhancing the reliability of Ohio's distribution grid.[760] It is beyond dispute that such enhanced reliability benefits both customers and the public interest. As Company witness Moul testified at hearing:

> [M]ost of the PJM queue is natural gas-fired generation that is susceptible to interruptions during peak demand times, particularly in the winter; whereas, the plants that we're offering which go back to the value of resource diversity provide in the case of the Sammis plant 30 days of fuel on site that's controlled at the site. In the case of Davis-Besse, up to two years of fuel in the reactor core after refueling that's available without interruption to provide reliable power 24/7. So the reliability value of a natural gas plant that has an interruptible fuel supply isn't equivalent to that of a coal plant like Sammis or that of Davis-Besse.[761]

Indeed, the continued operation of reliable baseload generating like the Plants is particularly essential to prevent the shedding of retail load, which tends to reach peak demand

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[757] Sierra Club Brief, p. 73.

[758] Hearing Tr. Vol. IV (CONF), p. 2938 (Ruberto Cross).

[759] ELPC Brief, p. 24.

[760] Hearing Tr. Vol. 1, p. 96 (Mikkelsen Cross); *see also* Hearing Tr. Vol. I, pp. 112, 154 (Mikkelsen Cross); Hearing Tr. Vol. IV, p. 874 (Strah Cross).

[761] Hearing Tr. Vol. X, p. 2195 (Moul Cross); Hearing Tr. Vol. XI, p. 2255 (Moul Cross).

"during extreme weather events."[762] ELPC also misses the boat with regard to the economic benefits and avoidance of transmission upgrade costs that, as discussed above, the Economic Stability Program is uniquely positioned to provide. Hence, ELPC's criticism is meritless.

Based upon the Direct Testimony of Mr. Cole, Cleveland claims that the Companies should have relied on an ill-defined RFP process "to demonstrate the prudence of their resource decisions" regarding the proposed transaction.[763] As an initial matter, Cleveland is being disingenuous – in its brief, it claims that Mr. Cole believes that such processes are necessary for a "long-term asset investment, such as the PPA's 15-year or 8-year term."[764] In his direct testimony, however, Mr. Cole states that such processes are only necessary for "investments" that are "ten years ormore."[765] The terms of the proposed transaction and Rider RRS are only eight years.[766] Thus, on Cleveland's witness's own terms, no such process is applicable here.

In addition, in the context of his discussion for the need for an RFP is his Direct Testimony, Mr. Cole stated that such a process was needed "to provide reasonable assurance of due diligence."[767] Yet, as noted above, the Companies clearly engaged in an extensive due diligence process – no such additional "assurances" are required here. Further, at hearing, Mr. Cole admitted that he had done no study or reviewed any studies related to power purchase agreements, such as the proposed transaction, that result from such RFPs.[768] Mr. Cole further admitted that he did not know how often RFPs are used by investor-owned utilities in

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[762] Hearing Tr. Vol. XI, p. 2380 (Moul Cross).

[763] Cleveland Brief, p. 8. Other intervenors make similar claims. *See, e.g.*, CMSD Brief, p. 8; OCC Brief, p. 8; ELPC Brief, p. 22.

[764] Cleveland Brief, p. 8.

[765] Cole Dir., p. 5.

[766] *See* Third Supp. Stip., Section V.A.1; Mikkelsen Fifth Supp., p. 3.

[767] Cole Direct, p. 5.

[768] Hearing Tr. Vol. XXI, p. 4212 (Cole Cross).

restructured states.[769] He also admitted that he had not reviewed any of the costs for David-Besse or Sammis.[770] Further, Mr. Cole also admitted that he was not aware of any other Ohio baseload coal and nuclear assets available on the market today.[771] Moreover, as Mr. Ruberto testified at hearing, given the unique attributes of the Plants no RFP was necessary:

> We did not because when we looked at the assets that were part of the proposal from FES, they provided many unique benefits, such as diversity of fuel, such as the economic benefits to the region and to the state. We looked at the improvements – or the effect on reliability should these plants be taken out of service. And when you combine all that, there isn't a reasonable substitute that an RFP would have been able to provide so we didn't consider it necessary to do an RFP to complete this evaluation.[772]

Thus, Cleveland's claims are misplaced.

Like Cleveland, ELPC argues that the Companies should have identified a range of alternative generation assets as opposed to "their narrow assessment of the FES plants standing alone."[773] To support this claim, ELPC relies on a case from the Connecticut Department of Utility Control (the "Connecticut Commission"), *DPUC Investigation of Measures to Reduce Federally Mandated Congestion Charges (Long Term Measures)*, Docket no. 05-07-14PH02, 2007 Conn. PUC LEXIS 108 (May 3, 2007), cited in the Direct Testimony of Company witness Strah. Mr. Strah cites the case to show that utilities in other restructured states have entered into long-term contracts on behalf of all their customers.[774] ELPC, however, goes on to note that in *DPUC Investigation* an RFP process was used to identify a "range in net benefits" regarding a

[769] Hearing Tr. Vol. XXI, p. 4212 (Cole Cross).

[770] Hearing Tr. Vol. XXI, p. 4206 (Cole Cross).

[771] Hearing Tr. Vol. XXI, pp. 4213-14 (Cole Cross).

[772] Hearing Tr. Vol. XIII, p. 2748 (Ruberto Cross).

[773] ELPC Brief, p. 28.

[774] Strah Direct, p. 15.

proposed long-term capacity resource contract.[775] ELPC's reliance on *DPUC Investigation* is inapposite.

In *DPUC Investigation*, the Connecticut legislature was concerned about the long-term viability of the state's capacity resources and wanted to secure future capacity to "provide much needed resources to supplement Connecticut's aging generation fleet."[776] To that end, the Connecticut legislature passed legislation mandating that the Connecticut Commission "issue a RFP to procure new or incremental capacity to reduce the impact of [Federally Mandated Congestion Charges] on Connecticut ratepayers through [Connecticut's Energy Independence Act]."[777] As defined in the Act, "eligible capacity includes generation, demand response, and energy efficiency."[778] The Connecticut Commission used a "range in net [financial] benefits" to identify that combination of capacity resources which best met the state's long-term capacity needs.[779]

Notably, in *DPUC Investigation* the capacity resources involved were fungible – it did not matter what kind of capacity, e.g., demand response, generation, or energy efficiency, or mix thereof that was utilized. Capacity was capacity and any type could be substituted in for another type based upon availability and cost. That is not the case here. Again, as Mr. Ruberto testified at hearing, given the "unique benefits" provided by the Plants in terms of "diversity of fuel…economic benefits to the region and to the state…the effect on reliability should these plants be taken out of service."[780] Taken together, the EDU Team surmised that there was no

[775] ELPC Brief, p. 28.

[776] *DPUC Investigation* at *6.

[777] *DPUC Investigation* at *2.

[778] *DPUC Investigation* at *2.

[779] *DPUC Investigation* at *6, n. 1.

[780] Hearing Tr. Vol. XIII, p. 2748 (Ruberto Cross).

"reasonable substitute" available in the Ohio generation market for the Plants, *i.e.*, baseload facilities with onsite fuel supply deliverable on a 24/7 basis combined with all of the associated economic benefits.[781] Given the lack of fungible generation assets, *DPUC Investigation* has no applicability here.

ELPC also claims that "Company witness Moul testified that in his experience at FES, the FirstEnergy business development group would produce an asset valuation in the form of a range rather than a single value when considering an asset purchase."[782] Mr. Moul testified, however, that "typically" a "single value" was received from the business development group in the case of a contemplated asset purchase, a "range" was much more the exception than the rule.[783] Moreover, ELPC again misses Mr. Ruberto's point regarding the lack of a "real substitute" for the Plants. Simply because in certain isolated contexts the Companies occasionally relied on a "range" of values does not mean that they should have done so here. The unique attributes of the Plants explain why. Thus, ELPC's argument is meritless.

ELPC further argues that the Commission needs "reassurances" that the proposed transaction between the Companies and FES is "just and reasonable."[784] ELPC points to AEP's second ESP case, Case No. 11-346-EL-SSO ("*AEP ESP 2*"), for supposed guidance. In that case, according to ELPC, the Commission allowed the EDU "to procure capacity" from its generation affiliate during the EDU's transition to full corporate separation.[785] ELPC claims that in *AEP ESP 2* the Commission "allowed" the procurement "to stand…based on [the

[781] Hearing Tr. Vol. XIII, p. 2748 (Ruberto Cross).

[782] ELPC Brief at pp. 28-29.

[783] Hearing Tr. Vol. X, p. 2229 (Moul Cross).

[784] ELPC Brief, p. 32.

[785] ELPC Brief, p. 32.

Commission's] recognition" that the "'contract between AEP-Ohio and GenResources is subject to prior FERC approval'".[786]

ELPC misreads *AEP ESP 2*. In that case, as well as here, the Commission was faced with a wholesale transaction that was beyond its review. The Commission, recognizing the limits of its jurisdiction, took a hands-off approach recognizing that the generation transaction between AEP Ohio and its affiliate would be subject to the processes of FERC review available under the Federal Power Act. There is no need for a different approach here. Affiliate transactions, such as the proposed transaction discussed in this case, are subject to FERC's jurisdiction. FES and the Companies have a waiver of the affiliate transaction restrictions. The propriety of that waiver (and of the type of any review to be undertaken by FERC) as applied to the proposed transaction is an issue for FERC – and not the Commission here. Indeed, some parties to this case have already raised that issue before FERC.[787] Moreover, several parties to this case have filed a complaint at FERC regarding the proposed transaction. Thus, to the extent FERC deems any review necessary, it will have the opportunity to do so.

In any event, the state compensation mechanism at issue in *AEP ESP 2*, which allegedly functioned as a putative "benchmark" according to ELPC,[788] was determined to be a reasonable proxy for the capacity costs incurred by AEP Ohio's generation affiliate, GenResources. As the Commission found in *AEP ESP 2*:

> The Commission finds, that once corporate separation is effective and AEP-Ohio procures its generation from GenResources that it is appropriate and reasonable for certain revenues to pass-through AEP-Ohio to GenResources. Specifically, the revenues AEP-Ohio receives, after corporate separation is implemented, from the RSR which are not allocated to recovery of the deferral, revenue equivalent to the capacity charge of $188.99/MW-day authorized in

[786] ELPC Brief, p. 32 (citing *AEP ESP 2* Case Opinion and Order at 60 (Aug. 8, 2012)).

[787] *See Electric Power Supply Assoc. v. FirstEnergy Solutions Corp.*, FERC Docket No. EL-16-34-000.

[788] ELPC Brief, p. 31.

> Case No. 10-2929-EL-UNC, generation-based revenues from SSO customers, and revenue for energy sales to shopping customers, should flow to GenResources.[789]

In Case 10-2929-EL-UNC ("AEP Capacity Case"), the Commission found:

> As discussed above, the Commission believes that AEP-Ohio's capacity costs, rather than RPM-based pricing, should form the basis of the state compensation mechanism established in this proceeding. Upon review of the considerable evidence in this proceeding, we find that the record supports compensation of $188.88/MW-day as an appropriate charge to enable AEP-Ohio to recover its capacity costs for its FRR obligations from CRES providers.[790]

The Commission further noted that what was being approved was a "cost-based capacity pricing mechanism."[791]

As applied here, the negotiated price to be paid by the Companies is tied to FES's costs. Thus, using the "benchmark" from the *AEP ESP 2* case (for capacity, at least), the price provisions of the Final Term Sheet here pass muster.

(ii) There is no need to modify the PPA to include renewable resources.

ELPC argues, based on the testimony of MAREC witness Burcat, that the ESP should include a competitive solicitation for renewable resources.[792] ELPC and MAREC's proposal is, however, premised on a suspect foundation and would not meaningfully add to Stipulated ESP IV.

As an initial matter, ELPC and MAREC did no study relating to the economic benefits of MAREC's proposal.[793] Nor did it do an analysis as to whether new transmission would be

789 *AEP ESP 2* Opinion and Order at 60.

790 *AEP Capacity Case*, Opinion and Order at 33 (July 2, 2012).

791 *AEP Capacity Case*, Opinion and Order at 33 (July 2, 2012).

792 ELPC Brief, pp. 24-25.

793 Hearing Tr. Vol. XXIV, p. 4946 (Burcat Cross).

needed as a result of its proposal.[794] MAREC has also not done a study on the cost of utilizing wind resources to comply with the CPP as compared to other options to comply.[795] And Mr. Burcat never even reviewed Company witness Evans' errata, in which Mr. Evans concluded that "Sammis is a valuable asset for Ohio's compliance with the CPP. . . according to the U.S. EPA's modeling."[796] Further, though wind resources may not be subject to fuel price volatility, they are inherently intermittent in nature and cannot provide the reliability benefits and the certainty of an ability to generate that the Plants bring to the Companies' customers.[797] As Company witness Harden testified, the Plants are "bedrock" units that "are operating all the time so that the lights come on when we flip switches in our homes."[798] Simply put, the Plants are always available to provide power.[799] In contrast, because wind resources are intermittent, difficult to dispatch, and only useful when the wind is blowing, they will often not correspond to peak demand during hot summer months.[800] Thus, the competitive solicitation MAREC seeks for its wind resources is of dubious value to customers and is unnecessary to Ohio's compliance with the CPP.

ELPC argues that PJM's CP rules could address the reliability problems with renewable resources.[801] This argument was not made by any witness at hearing and defies logic. The CP product, though helpful, does not transform renewable resources into baseload resources capable of being dispatched to meet load.

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[794] Hearing Tr. Vol. XXIV, p. 4947 (Burcat Cross).

[795] Hearing Tr. Vol. XXIV, p. 4948 (Burcat Cross).

[796] Hearing Tr. Vol. XXIV, p. 4953 (Burcat Cross); Evans Errata, p. 2.

[797] Hearing Tr. Vol. XI, p. 2401 (Moul Cross).

[798] Hearing Tr. Vol. XII, p. 2523 (Harden Cross).

[799] Harden Direct, p. 9; Moul Direct, p. 10.

[800] Hearing Tr. Vol. XII, p. 2508 (Harden Cross).

[801] ELPC Brief, p. 25.

ELPC attempts to avoid this obvious conclusion by claiming that energy efficiency can help protect customers from rising prices and be part of a diverse fuel mix.[802] This is incorrect. ELPC is confusing the issue of whether energy efficiency can be cost effective for customers (which is dependent on pricing for that product) and whether it can provide reliability (which is dependent on physics). As explained by Mr. Rose, nearly all the demand response that has cleared the PJM capacity market is only required to operate in the summer months for up to 60 hours per year.[803] Therefore, to state the obvious, such resources do not impact reliability year round. Moreover, as a result of the very CP product that ELPC relies on, demand response is unlikely to be as cost effective in the future.[804] Accordingly, ELPC's argument lacks merit.

(iii) Exelon's proposal to participate in an RFP process on its terms is a litigation strategy, not a *bona fide* offer.

By its reckoning, Exelon would have the Commission believe that Exelon has offered the deal of the century to the Companies and their customers. Nothing could be further from the truth. The Exelon "offer" is not a *bona fide* offer at all. Indeed, the Exelon "offer" simply was cooked up as part of Exelon's "litigation strategy" in this case. Moreover, even if the Exelon "offer" was a *bona fide* offer, which it most certainly is not, the product "offered" is far inferior and not comparable to the product that is the subject of the proposed transaction between FES and the Companies.

In its brief, Exelon describes its "offer" and the process by which it purportedly resulted as follows:

> To prepare the offer, Mr. Campbell requested that Exelon's commercial group develop a quote for an eight-year bundled fixed price for energy and capacity delivered to ATSI from 100% zero

[802] ELPC Brief, p. 26.

[803] Rose Direct, p. 15.

[804] Rose Direct, pp. 39-42.

> carbon resources, with Exelon maintaining *100%* of the PJM capacity performance risk. He requested a maximum fixed price to which Exelon would commit for a fixed quantity product of anywhere up to 3,000 MW (the combined nameplate capacity of the Davis-Besse and Sammis plants) of unforced capacity ("UCAP") and around-the-clock ("ATC") energy for the same eight-year period…the Exelon offer…was approved by Exelon's Chief Executive Officer.[805]

Mr. Campbell's cross-examination, however, reveals that the deal specifics and process sketched out above have been manufactured out of whole cloth by Exelon as litigation strategy.

- Mr. Campbell admitted that Exelon's "proposal," for lack of a better term, was raised at a "litigation strategy" meeting regarding Mr. Campbell's supplemental testimony during which there was no discussion of the specific price that Exelon would offer.[806] Indeed, what Exelon's CEO approved was not the "offer" itself: "Mr. Crane [Exelon's CEO]…gave his approval *to go forward with the testimony* that included the *commitment*."[807]
- Mr. Campbell admitted that he was never aware of whether his proposal was ever properly approved.[808] He did not know if it had been vetted by Exelon's Board of Directors or even reviewed by any board member other than Mr. Crane.[809] Nor did he know whether his proposal was ever reviewed or approved by Exelon's Risk and Finance Committee.[810]

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[805] Exelon Brief, p. 73 (footnotes omitted). It is telling that Exelon waits until page 72 of its 79-page brief to explain its proposed multi-billion dollar "offer" and then devotes a mere two pages to it.

[806] Hearing Tr. Vol. XXXVIII, pp. 8024-25 (Campbell Cross).

[807] Hearing Tr. Vol. XXXVIII, p. 8025 (Campbell Cross) (emphasis added).

[808] Hearing Tr. Vol. XXXVIII, pp. 8025-8026 (Campbell Cross).

[809] Hearing Tr. Vol. XXXVIII, pp. 8025-26 (Campbell Cross).

[810] Hearing Tr. Vol. XXXVIII, pp. 8025-26; 8030 (Campbell Cross).

- Mr. Campbell admitted that he had no discussion with anyone regarding the need to meet any performance guarantees or credit requirements and was unaware of whether Exelon had made any effort to meet such guarantees or requirements.[811]
- Mr. Campbell admitted that, even internally, Exelon referred to the proposal merely as an "indicative offer." [812]
- Mr. Campbell admitted that this "indicative offer," in contrast to past practices by Exelon involving *bona fide* offers, was never made company to company, *i.e.*, outside of being proposed as part of testimony.[813]
- Mr. Campbell admitted that Exelon's "offer" was only contingent on the Companies undertaking a competitive bid process for a product of the type described in his testimony.[814]
- Mr. Campbell was impeached by his prior deposition testimony in which he agreed that he did not know whether the Companies could accept Exelon's proposal and make it binding on Exelon.[815]

Given the above admissions, Exelon still has the gall to refer to what Mr. Campbell proposed in his testimony as a "commercial offer."[816] Even a first-year law student would recognize that this is not the case. What Exelon has done here is adopt a litigation stance – *i.e.*, to be able to argue that there was an "offer" – not to make a *bona fide* "commercial offer" to the Companies.

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[811] Hearing Tr. Vol. XXXVIII, p. 8035 (Campbell Cross).

[812] Hearing Tr. Vol. XXXVIII, pp. 8036-37 (Campbell Cross).

[813] Hearing Tr. Vol. XXXVIII, pp. 8035-39 (Campbell Cross).

[814] Hearing Tr. Vol. XXXVIII, pp. 8047-8048 (Campbell Cross).

[815] Hearing Tr. Vol. XXXVIII, pp. 8044-46 (Campbell Cross).

[816] Exelon Brief, p. 72.

Moreover, as noted, the proposal in Mr. Campbell's testimony related to a specific product. Thus, even if Exelon had made a *bona fide* offer (which it most certainly has not) the product Exelon proposes is far inferior to and not comparable with the product that is the subject of the proposed transaction between FES and the Companies. What the Companies have already negotiated Exelon simply cannot provide. In every significant way – energy, capacity, reliability support, megawatts provided, ancillary services – Exelon's "product" is inferior.

Regarding energy, Mr. Campbell admitted that Exelon would propose only to deliver an "around the clock" product, whereas FES offers energy that may be economically dispatched.[817] Thus, under the transaction proposed here the Companies can maximize output of the Plants during times of higher LMPs and minimize output and avoid costs during times with lower LMPs.[818] This allows customers to get the benefit of a flexible dispatch regime that will maximize revenues and minimize cost – which deflates Exelon's erstwhile claims regarding the magnitude of the savings Exelon's "offer" supposedly provides.[819]

The difference in when and how the Companies could take and offer outputs into the market undercuts Mr. Campbell's calculations regarding alleged "savings" offered by Exelon's proposal. In truth, he failed to consider the difference in revenues and costs that would be obtained under an economic dispatch transaction versus an "around the clock" purchase .

The table below provides a simple hypothetical example that shows the difference between an around-the-clock ("ATC") product and an economically dispatchable product that are equal in volume over two hours.[820] The example assumes in one case that there is an

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[817] Hearing Tr. Vol. XXXVIII, pp. 8050-51 (Campbell Cross).

[818] Hearing Tr. Vol. XXXVIII, pp. 8050-51 (Campbell Cross).

[819] *See* Exelon Brief, p. 73.

[820] Counsel for the Companies walked Exelon witness Campbell through a similar example at the hearing. *See* Hearing Tr. Vol. XXXVIII, pp. 8053-8057 (Campbell Cross).

economically dispatchable product with a maximum level of operation of 3 MW and a minimum level of operation of 1 MW with a variable cost of $30 per MWh and a fixed cost of $50. Anytime the hourly LMP is less than $30/MWh, the dispatchable product generates at 1 MW in that hour, and anytime the hourly LMP is equal to or greater than $30/MWh the dispatchable product generates at 3MW in that hour. The example also assumes a second case involving an ATC product set at 2MW per hour so that it too totals to 4 MWh over a two-hour period. The example demonstrates that the dispatchable product produces higher energy revenues than the ATC product for the same volume of MWh over the two-hour period. Specifically, the dispatchable product produced $310 of energy revenue and the ATC product only produced $220 in energy revenue (these amounts appear in bold in the table below).

Economically Dispatchable Product vs. Around-The-Clock Product

Economically Dispatchable Product with 3 MW maximum & 1 MW minimum with $30/MWH variable cost and $50 fixed cost

			Market Revenue				Cost		
Hour	LMP	MW	Energy	Capacity	Ancillary *	Total	Variable	Fixed	Total
	A	B	C	D	E	F	G	H	I
			A*B			C+D+E	B*30		G+H
1	100	3	300		1	301	90		
2	10	1	10		1	11	30		
Subtotal		4	**310**		2	312	120	50	170
Capacity @ $20/MW/day		3		60		60			
Total						372	120	50	170
Revenue greater than cost									202

* Ancillary Revenue is from the market and from FERC tariff.

Around-The-Clock Product with $48/MWh cost

			Market Revenue			
Hour	LMP $/MWh	MW	Energy	Capacity	Total	Cost
	A	B	C	D	D	E
			A*B	B*20	(C)+(D)	B*48
1	100	2	200		200	96
2	10	2	20		20	96
Subtotal		4	**220**		220	192
Capacity @ $20/MW/day		2		40	40	
Total					260	192
Revenue greater than cost						68

Mr. Campbell's testimony purports to show the difference between Exelon's proposed ATC product and the dispatchable product offered by FES. [**BEGIN CONFIDENTIAL**] [redacted][821][**END CONFIDENTIAL**] Adopting this simplistic and methodologically flawed approach enabled him to arrive at the alleged "savings" amount claimed in his testimony. But this compares apples with oranges. As the above shows,

[821] *See* Campbell Second Supp., p. 7.

he failed to take into account in his testimony that dispatchable products have lower variable costs than ATC products.[822] He simply ignores the higher revenues that a dispatchable product would provide the Companies for the same volume of annual market sales. The example further shows that the dispatchable product comes in at a higher capacity value in MW than the ATC product. (In fact, Mr. Campbell admitted that the FES product offered more capacity.[823]) As such, the disptachable product will generate more capacity revenue than the ATC product, assuming that both products are valued at the same location.

In the case of capacity, and contrary to his Second Supplemental Testimony, Mr. Campbell admitted that Exelon would not deliver any capacity into the ATSI zone.[824] Instead, and unlike in the FES proposed transaction, Exelon's proposed capacity would be previously cleared and "non-unit specific."[825] In fact, according the PJM's eRPM Guidelines, non-unit specific capacity transactions are not physical transfers of capacity. They are only purely financial transactions.[826]

Critically, Exelon's proposed product does little good to support capacity needs in ATSI. Even if Exelon proposed unit specific capacity transactions, there is no Exelon generation in ATSI[827] (and virtually none in Ohio[828]). Mr. Campbell admitted that he did not know whether Exelon's generation facilities, unlike the Plants, could support local reliability, or provide voltage or VAR support within ATSI.[829] Additionally, Mr. Campbell admitted that because none

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[822] *See* Campbell Second Supp., pp. 6-7.

[823] Hearing Tr. Vol. XXXVIII, pp. 8068-8069 (Campbell Cross).

[824] Hearing Tr. Vol. XXXVIII, pp. 8057-60 (Campbell Cross).

[825] Hearing Tr. Vol. XXXVIII, p. 8060 (Campbell Cross).

[826] Hearing Tr. Vol. XXXVIII, p. 8067 (Campbell Cross).

[827] Hearing Tr. Vol. XXXVIII, p. 8069 (Campbell Cross).

[828] Hearing Tr. Vol. XXXVIII, pp. 8069-70 (Campbell Cross).

[829] Hearing Tr. Vol. XXXVIII, p. 8070 (Campbell Cross).

of Exelon's generation resources are in ATSI, the performance of those resources would have no relation to the CP requirements within ATSI.[830] Thus, Exelon's claim that "the capacity product included in the offer is the PJM CP product"[831] is simply beside the point.

Further, as Mr. Campbell admitted at hearing, the Exelon alleged "offer" is for less than the 3,000-plus MW that is available through the proposed transaction between FES and the Companies[832] -- yet Exelon continues to insist that it is offering "a fixed quantity product of anywhere up to 3,000 MW (the combined nameplate capacity of the Davis-Besse and Sammis plants)."[833] Also, unlike here, Exelon's alleged product, as Mr. Campbell admitted, does not include ancillary services.[834]

More generally, Exelon's proposal also fails to deliver the unique attributes and other associated benefits that the Plants would provide under the proposed transaction. Indeed, as Ms. Mikkelsen testified at length at the hearing:

> [I]t did not appear to be an offer in any way, shape, or form, and by that I mean there were no specific terms and conditions included. The description in the testimony that talked about delivering capacity to ATSI ran counter to my understanding of how the capacity markets in PJM work and suggested to me that what was written there didn't really represent an offer.
>
> And, further, probably more importantly, it didn't -- it missed the mark on the benefits that the companies were looking for on behalf of the customers in the state of Ohio with respect to our proposed Economic Stability Program. . . .

[830] Hearing Tr. Vol. XXXVIII, p. 8069 (Campbell Cross).

[831] Exelon Brief, p. 73.

[832] Hearing Tr. Vol. XXXVIII, pp. 8068-69 (Campbell Cross).

[833] Exelon Brief, p. 73.

[834] Hearing Tr. Vol. XXXVIII, p. 8070 (Campbell Cross).

> So, again, having not studied it in any detail, it didn't strike me as an offer, and it didn't seem the least bit comparable to what the company has before the Commission today.[835]

Thus, Exelon's "offer" cannot be taken seriously and in no way provides a meaningful alternative to what the Companies have negotiated with FES.

4. Rider RRS promotes reliability.

a. Rider RRS removes uncertainty over whether Plants will retire.

Rider RRS removes uncertainty over whether the Plants will retire. This issue is discussed in detail in the Companies' Initial Brief at pages 125-30 and in Section III.A.5. below.

b. Rider RRS will have the effect of promoting reliable retail electric service.

As the evidence of record amply shows, baseload units like the Plants make a significant contribution to reliability in Ohio, particularly when the grid is stressed, e.g., due to extreme weather events. As Company witness Harden testified:

> In essence, [the Plants as] baseload units are the bedrock that ensures reliability for retail customers by operating around the clock and providing voltage support and other services that are essential to the reliable operation of the grid. … Because these Plants have an on-site fuel capability, they are available on a 24x7 basis and can support prolonged operations during disruptive events such as the January 2014 Polar Vortex. Sammis targets an on-site fuel supply of approximately 30 days. Davis-Besse runs approximately two years between refueling outages, and can operate some time beyond that at a slightly reduced percentage of its rated power. Davis-Besse also targets having new fuel on site more than 30 days in advance of planned refueling outages. The operating characteristics of nuclear and coal plants make them essential to reliability in times of stress on the grid.[836]

Notably, the continued operation of reliable baseload generating like the Plants is particularly essential to prevent the shedding of retail load, which tends to reach peak demand

[835] Hearing Tr. Vol. XXXVII, pp. 7829-31.

[836] Harden Direct, p. 9.

"during extreme weather events."[837] Thus, as fuel-diverse, baseload generating assets with onsite fuel supply, the Plants clearly impact the reliability of the Ohio distribution grid. In turn, resource adequacy and fuel diversity issues posed by their potential to cease operation fall squarely within the Commission's wheelhouse. Attempts by various intervenors to argue otherwise fall flat.

Some intervenors claim that the Plants are unnecessary because of new generation construction in Ohio.[838] The overwhelming majority of such projects are never completed. According to PJM's State of the Market Reports: "Of the projects that have completed the queue process, 87.6 percent of the MW that entered the queue withdrew at some point in the future."[839] And further: "The queue contains a substantial number of projects that are not likely to be built."[840] Indeed, PJM historical data shows that only seven percent of new generation projects actually go into service.[841]

Further, of the small percentage of generation projects that ultimately become operational, the overwhelming majority have been gas-fired.[842] Indeed, the Commission publicly has expressed concern about this very trend, i.e., "the dash to gas," and its potential to negatively impact reliability in Ohio:

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[837] Hearing Tr. Vol. XI, p. 2380 (Moul Cross).

[838] *See, e.g.*, Sierra Club Brief, p. 17; NOPEC Brief, p. 40.

[839] Company Ex. 76 (State of the Market Report for PJM Q2 2015), p. 397.

[840] Company Ex. 75 (State of the Market Report for PJM Q1 2014), p. 361.

[841] *See* Sierra Club Ex. 58 (2014 PJM Interconnection Queue Statistics Update), p. 6.

[842] *See, e.g.,* Hearing Tr. Vol. XXIV, p. 4875 (Kahal Cross); Hearing Tr. Vol. XXIV, p. 5017 (Bowring Cross); Hearing Tr. Vol. XXVI, p. 5206 (Campbell Cross).

> The 'dash to gas' scenario causes concern to economic regulators because the more dependent a system is on one specific fuel type, the more risk and volatility there exists for [customers].[843]

And further:

> [A] significant portion of the retiring megawatts being replaced by natural gas resources, we cannot afford to forget about protecting our current resources that help in hedging against any unforeseen natural gas curtailments.[844]

The outage events during the 2014 Polar Vortex and the 2015 Siberian Express demonstrate why the Commission should be concerned. In its report on the Polar Vortex, PJM noted:

> [N]atural-gas-fired generators accounted for 47 percent of the unavailable megawatts…[F]or a frame of reference, in PJM, gas-fired plants represent 29 percent of total generation (in megawatts), and coal-fired plants represent 41 percent.[845]

Interruptions caused by, and outages of, gas-fired generation thus were disproportionate to the quantity of natural gas generation that comprises the PJM generation mix. Several intervenor witnesses to this proceeding, including Mr. Scarpignato, admitted the same during cross examination at hearing.[846]

Likewise, in its 2015 Winter Report, PJM once again found that gas-fired units were disproportionately responsible for the forced outages that occurred during the Siberian

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[843] Moul Direct, p. 9 (quoting Comments Submitted on Behalf of the Public Utilities Commission of Ohio, p. 8, Technical Conference on Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators, FERC Docket No. AD14-8-000 (May 15, 2014)) .

[844] Moul Direct, p. 7-8 (quoting Comments Submitted on Behalf of the Public Utilities Commission of Ohio, pp. 7-8, Technical Conference on Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators, FERC Docket No. AD14-8-000 (May 15, 2014)).

[845] Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events, PJM Interconnection (May 8, 2014), p. 25 (Sierra Club Ex. 8).

[846] Hearing Tr. Vol. XXIV, pp. 5101-02 (Scarpignato Cross) (admitting disproportionate contribution of gas-fired generation to reliability issues during 2014 Polar Vortex); Hearing Tr. Vol. XXII, p. 4575 (Wilson Cross) (admitting same); Hearing Tr. Vol. XXVIII, pp. 5638-39 (Kalt Cross) (admitting same).

Express.[847] As a percentage of total outage caused by interruptions perspective, natural gas-fired generation fared *worse* in 2015 as compared to 2014.[848] In contrast, baseload nuclear and coal-fired plants with onsite-fuel supplies, like the Plants, ran relatively reliably during the winters of 2014 and 2015.[849] Thus, even if Mr. Scarpignato were correct regarding the alleged existence of adequate incentives for new generation facilities in Ohio, the facilities that have come online are almost exclusively gas-fired. As such, these facilities simply do not address the resource adequacy and fuel diversityconcerns raised by the Commission.

c. **The Commission should not ignore the reliability benefits of Rider RRS obtained from resource diversification.**

PJM asserts that the Commission should ignore the reliability benefits provided by Rider RRS, calling these benefits a "red herring."[850] According to PJM, the reliability of the bulk electric system is PJM's responsibility, and the Commission should rely on the ability of wholesale market signals to attract sufficient generation and ensure resource adequacy. The Commission should not take PJM's invitation to turn a blind eye to fuel diversity issues that could severely impact Ohio consumers.

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[847] 2015 Winter Report, PJM Interconnection (May 13, 2015), p. 6 (IGS Ex. 1). *See also* IGS Ex. 1, p. 22, Figures 21 and 22 (showing that 30% of forced outages on February 20, 2015 were due to natural gas while 24% of forced outages were due to natural gas on January 7, 2014). The report noted some small incremental improvements between 2014 and 2015, but as the 2015 outage rate for gas demonstrates the underlying reliability issues were not alleviated. IGS Ex. 1, p. 5. Indeed, PJM noted that such improvements were "short-term" and the recent CP product was deemed "inadequate" as a "long-term solution." IGS Ex. 1, p. 6.

[848] Indeed, as Mr. Rose testified at hearing, "Furthermore, when you look at the gas versus the coal outages [for 2015], take a look at the denominator, not just the numerator. There is, as I indicated, more total outages for gas plants over less gas plants. They should have had much less. In fact, they had more." Hearing Tr. Vol. VII, p. 1509 (Rose Cross).

[849] Hearing Tr. Vol. X, p. 2195 (Moul Cross); Hearing Tr. Vol. XI, p. 2255 (Moul Cross). Further, as coal and nuclear retirements accelerate, there is no guarantee that the gas generation projects currently in the PJM generation queue will even come online. "Of the projects that have completed the queue process, 87.6 percent of the MW that entered the queue withdrew at some point in the future." Company Ex. 76 (State of the Market Report for PJM Q2 2015), p. 397. *See also* Company Ex. 75 (State of the Market Report for PJM Q1 2014), p. 361 ("The queue contains a substantial number of projects that are not likely to be built.").

[850] PJM Brief, p. 11.

Under the Federal Power Act, *both* the federal government and the states play a role in maintaining reliable electric service to customers.[851] While FERC (and consequently PJM) has responsibility for the reliability of the bulk electric transmission system, states retain the responsibility to "ensure the safety, adequacy, and reliability of electric service" within their borders.[852] The Commission should not ignore this important responsibility. As the Companies explained in their Initial Brief, Rider RRS will help maintain fuel diversity in a market that is increasingly coming to rely on natural gas-fired units.[853] Resource diversity safeguards reliable electric service in Ohio during periods of peak stress, as the Polar Vortex illustrated in 2014. Accordingly, the question of resource diversity is properly before this Commission.

Moreover, while PJM asserts that its capacity market ensures resource adequacy across its multi-state footprint, those markets are indifferent to fuel diversity. While this approach may ensure resource adequacy in the very broadest sense – sufficient megawatts to meet project system needs plus a reserve margin – it ignores other aspects of resource adequacy, such as fuel diversity and long-term resource planning, that are within the purview of the states. As a result, the resource adequacy benefits of Rider RRS should be a critical factor in the Commission's analysis.[854]

The Commission expressly has recognized its responsibility to ensure the reliability of Ohio's distribution system, specifically through the preservation of fuel diversity such as that provided by the Plants. Indeed, the Commission publicly has stated:

> It is the responsibility of the PUCO to carry out the policy of the state of Ohio to ensure the diversity of electricity resources. The

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[851] 16 U.S.C. § 824o.

[852] *Id.* § 824o(i)(3).

[853] Companies' Initial Brief, p. 27.

> benefits of energy diversity to security, affordability, and reliability are well documented.[855]

Further, as OEC/EDF witness Roberto admitted, "The Public Utilities Commission needs to take into account the goals of the state of Ohio, and diversity and reliability of the supply are included in those goals."[856] Likewise, Mr. Scarpignato agreed under cross examination that "a state might also have an interest in reliability for its citizens."[857] Other intervenor witnesses, including PJM's independent market monitor, Dr. Bowring, also made similar admissions. Dr. Bowring agreed that that supply diversity is an important factor for the Commission to consider when evaluating PPA rider proposals.[858] OCC/NOPEC witness Kahal admitted that the Commission has a role to play in ensuring reliability for retail electric customers.[859] Thus, the Commission should not ignore the reliability benefits of Rider RRS.

d. The Companies have not overstated the potential cost of transmission upgrades to maintain reliability if the Plants retire.

The Companies detailed in their Initial Brief that retirement of the Plants would result in many overloaded transmission lines on PJM's transmission system in 2019, which would necessitate costly transmission upgrades in a range between $436.5 million and $1.1 billion.[860] Sierra Club, ELPC and OMA argue that the transmission impact study performed by the

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[855] Comments On The U.S. EPA Carbon Paper Submitted On Behalf Of The Public Utilities Commission Of Ohio (Dec.16,2013) (available at http://www.naruc.org/ Publications/ Public%20Utilities%20Commission %20of%20Ohio.pdf) (quoted in Moul Direct, pp. 6-7) (emphasis added).

[856] Hearing Tr. Vol. XXI, p. 4168 (Roberto Cross).

[857] Hearing Tr. Vol. XXIV p. 5110-11 (Scarpignato Cross).

[858] Hearing Tr. Vol. XXIV, p. 5038 (Bowring Cross).

[859] Hearing Tr. Vol. XXIV, p. 4894 (Kahal Cross).

[860] Companies Brief, pp. 27-29, 67-71.

Companies' team of experts during the summer of 2014 is now outdated. They argue that it does not include the impact of updated load forecasts or new natural gas plants that may be built.[861]

These arguments overlook the fact that the Companies used PJM's methodology and its models of the transmission grid for the 2017-19 time frame for the specific purpose of determining the impact of the Plants' retirement during that time frame.[862] Although opponents claim that one-off adjustments to PJM's model should have been made, changing individual inputs to PJM's models is clearly improper.[863] If you change PJM's model, you do not get the result that PJM would get, which is the point of the exercise. Even Sierra Club witness Lanzalotta agreed it is improper to add or subtract facilities from PJM's base case models.[864] The opponents' argument to add new natural gas plants that may be built is an excellent example of how tampering with PJM's model skews the study results. If the modeler adds new natural gas plants under construction or announced for development since the development of PJM's model, the modeler would also need to remove from PJM's model those generation plants that have withdrawn from the PJM queue or announced a retirement since development of the model.[865]

Moreover, PJM includes potential new generation - but not all announced generation in its model - to account for the fact that a very small percentage of announced generation actually gets built and goes into service.[866] According to PJM's State of the Market Reports: "Of the

[861] Sierra Club Brief, pp. 93-95; ELPC Brief, pp. 42-43; OMAEG Brief, pp. 31-32.

[862] Hearing Tr. Vol. XV, pp. 3226-29, 3236 (Phillips Cross); Hearing Tr. Vol. XVI, pp. 3402-04 (Phillips Redirect).

[863] Hearing Tr. Vol. XV, p. 3265 (Phillips Cross); Hearing Tr. Vol. XVI, pp. 3349-51 (Phillips Cross), 3406 (Phillips Recross); Hearing Tr. Vol. XXV, p. 5140 (Lanzalotta Cross) (Sierra Club witness Lanzalotta agreeing that you should use PJM's base case model for the year you are studying and should not add or subtract generating units not otherwise in PJM's model).

[864] *See* Hearing Tr. Vol. XXV, p. 5140 (Lanzalotta Cross).

[865] Hearing Tr. Vol. XVI, pp. 3402-03 (Phillips Redirect).

[866] Hearing Tr. Vol. XV, pp. 3226-29, 3234-35 (Phillips Cross).

projects that have completed the queue process, 87.6 percent of the MW that entered the queue withdrew at some point in the future."[867] And further: "The queue contains a substantial number of projects that are not likely to be built."[868] Indeed, PJM historical data shows that only seven percent of generation projects that enter the PJM queue actually go into service.[869] As a result, the generation deliverability study and N-1-1 study using PJM's 2019 RTEP model is a good view of the impact of the Plant's retirement as of June 1, 2019.[870]

Sierra Club and OMA attack other assumptions used in the transmission impact study. Sierra Club and OMA argue that the transmission impact study's assumption that Davis-Besse and all Sammis units retire by June 1, 2017 is highly implausible, and that as a result the projected costs of transmission upgrades is misleadingly large.[871] Sierra Club and OMA base this argument on the testimony of Sierra Club witness Lanzalotta.[872] In preparing his testimony, however, Mr. Lanzalotta made no effort to examine the possibility of a fewer-than-all-units retirement or to examine the economics of the units involved.[873] He also did not conduct a load flow study to determine what the impact would be on the transmission system if only some of the units retired, so he was unable to say that retiring a subset of units would reduce the magnitude of all of the overloads identified by Company witness Phillips.[874] He could only speculate about what might affect the Companies' actual, detailed studies. This was no more than an academic exercise, given that there is no proof that fewer than all of the units at these plants are at risk.

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[867] Company Ex. 76 (State of the Market Report for PJM Q2 2015), p. 397.

[868] Company Ex. 75 (State of the Market Report for PJM Q1 2014), p. 361.

[869] *See* Hearing Tr. Vol. XV, p. 3234; Sierra Club Ex. 58 (2014 PJM Interconnection Queue Statistics Update), p. 6.

[870] Hearing Tr. Vol. XV, p. 3264 (Phillips Cross); Hearing Tr. Vol. XVI, pp. 3402-03 (Phillips Redirect).

[871] Sierra Club Brief, pp. 91-92; OMAEG Brief, pp. 30-31.

[872] Lanzalotta Supp., pp. 4-6.

[873] Hearing Tr. Vol. XXV, pp. 5143-44 (Lanzalotta Cross).

[874] Hearing Tr. Vol. XXV, pp. 5144, 5146 (Lanzalotta Cross).

Sierra Club asserts that the assumption supporting Ms. Mikklsen's upper-end net present value estimate of $1.3 billion cost to customers – that every overloaded facility needs to be rebuilt instead of being reconductored – is unlikely.[875] However, this argument ignores the Companies' actual testimony. Company witness Phillips provided two estimates: a low-end estimate of $436.5 that assumes all violations can be remedied by reconductoring overloaded facilities (the least expensive alternative), and a high-end estimate of $1.1 billion that assumes all violations need to be remedied by rebuilding overloaded facilities. Company witness Phillips testified that the lower-end estimate of $436.5 million was conservative, and Sierra Club witness Lanzalotta agreed.[876] All agree it is unlikely that reconductoring will remedy all violations.[877] Instead, Mr. Phillips testified, PJM and transmission owners "will likely develop a solution that consists of a combination of new facilities and reconductoring/rebuilding existing facilities," as occurred when plants located along or near Lake Erie retired between 2012 and 2015.[878] Until PJM conducts its load flow study following the announcement of the retirement of the Sammis and Davis-Besse plants, it will not be known precisely what combination of new facilities, rebuilt facilities and reconductored facilities PJM will select to resolve reliability violations.[879] However, given the extensive list of violations that would result if both plants were retired, the higher end of Mr. Phillips' cost estimate fairly represents the total transmission cost.[880]

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[875] Sierra Club Brief, p. 95.

[876] Lanzalotta Supp., p. 6; Phillips Supp., pp. 4, 7-8. *See* Hearing Tr. Vol. XV, p. 3263 (Phillips Cross).

[877] Hearing Tr. Vol. XXV, p. 5150 (Lanzalotta Cross); Phillips Supp., pp. 7-9.

[878] Phillips Supp., pp. 9-10; Hearing Tr. Vol. XXV, p. 5151 (Lanzalotta Cross); Hearing Tr. Vol. XVI, p. 3285 (Phillips Cross).

[879] Hearing Tr. Vol. XXV, p. 5151 (Lanzalotta Cross); Phillips Supp., p. 10; Hearing Tr. Vol. XV, p. 3238 (Phillips Cross).

[880] Phillips Supp., p. 10 ("The inclusion of such new facilities will move the cost of the reliability solution away from the lower end of the cost spectrum and toward the higher end.")

This estimate is consistent with the Companies' recent experience with retirements of baseload plants built to serve their load. As discussed in the May 2012 report of PJM's Transmission Expansion Advisory Committee ("TEAC") and as summarized on Company witness Phillips' workpaper, PJM identified approximately $1 billion in transmission upgrades – new lines, new substations and upgrades to existing facilities – to address voltage and thermal violations resulting primarily from the Lake Plant retirements along Lake Erie.[881] OMAEG contends that the example of the FES and GenOn retirements that the Companies say required $1 billion in transmission upgrades is flawed, since those upgrades were necessitated by the retirements of other plants as well.[882] OMAEG overstates the effect of other retirements. While PJM also studied other retirements in the Western Region of PJM, and did identify one transmission upgrade primarily related to the retirement of a 332 MW facility in New Castle, Pennsylvania, the bulk of the upgrades related to the Lake Plants.[883] Notably, the only other substantial retirement in Ohio during this time period was the 1,118 MW Beckjord facility in southern Ohio, but Sierra Club's but Mr. Lanzalotta testified, based on a load flow study he conducted, that the Beckjord retirement did not cause any transmission overloads.[884]

Sierra Club's attacks on the Companies' transmission impact study are based in large part on the testimony of Sierra Club witness Lanzalotta. Because he conducted no load flow studies, he had no basis to contend that the list of facilities identified by Company witness Phillips that would be overloaded if the Plants retired was incorrect.[885]

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[881] *See* Hearing Tr. Vol. XVI, pp. 3336-42 (Phillips Cross); Sierra Club Ex. 60 (TEAC Report); Company Ex. 40, pp. 4-5.

[882] OMAEG Brief, p. 32.

[883] Sierra Club Ex. 60, pp. 6-8; Hearing Tr. Vol. XVI, pp. 3338-42 (Philips Cross).

[884] Hearing Tr. Vol. XXV, pp. 5140-41 (Lanzalotta Cross); Sierra Club Ex. 60, p. 6.

[885] Hearing Tr. Vol. XXV, p. 5142 (Lanzalotta Cross).

Sierra Club raised questions regarding the Companies' cost estimates, but its attacks offered only speculation, not fact. This is not the first time Sierra Club's transmission witness has offered speculation instead of fact as purported expert testimony. In a transmission proceeding involving Commonwealth Edison, the Illinois Commerce Commission chided Sierra Club witness Lanzalotta, who represented a group called Friends of the Prairie Path ("FOPP"), for providing the same type of slipshod testimony he provided here:

> The evidence demonstrated that Mr. Lanzalotta made numerous engineering and planning errors and omissions in designing FOPP's schemes. Mr. Lanzalotta admitted that he did not perform necessary load flow and voltage studies with respect to his plans. Such studies are essential in designing a reliable least-cost transmission network. Likewise, the evidence shows that Mr. Lanzalotta's PVRR analysis for his schemes is flawed due to equipment omissions and the omission of costs of acquiring private property. Furthermore, FOPP's 34 kV scheme requires the construction and installation of five new 34 kV lines, six new or expanded substations, and fourteen major new transformers. Its 138 kV plan along Ferry Road has construction feasibility questions associated with nonexistent or inadequate rights-of-way and no land for a substation site.[886]

In short, his testimony was based on speculation and was error prone. It lacked record support because he failed to conduct his own load flow and voltage studies. The same is true here.

NOPEC questions whether the avoided transmission cost benefit is merely delayed a few years by ESP IV.[887] NOPEC's argument is a straw man, given that it is based on a market price scenario that OCC/NOAC's witness admits is not in the Companies' testimony and appears nowhere else in the record.[888]

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[886] ***See In re Commonwealth Edison***, Docket No. 92-0221, 1995 Ill. PUC LEXIS 668, at *49-50 (Oct. 18, 1995). ***See also*** Hearing Tr. Vol. XXV, pp. 5142-43 (Lanzalotta Cross).

[887] NOPEC Brief, pp. 68-69 (citing OCC/NOPEC Ex. 11 (Kahal Second Supp., pp. 20-21)).

[888] Kahal Second Supp., pp. 20-21 ("In that case (which is not supported by any analysis), ..."); Hearing Tr. Vol. XXXVIII, pp. 8234-35 (Kahal Cross).

Sierra Club, OCC/NOAC and OMAEG also challenge the validity of the transmission impact study because, they claim, it was not conducted by an independent party.[889] OMAEG claims that the Companies used two of their own engineers.[890] To be sure, the study was performed by a team led by Gavin Cunningham, which used PJM's models and PJM's methodology.[891] But the team also included an outside consultant who is a former PJM employee with expertise in running the modeling the same as PJM would do.[892]

Further, an outside firm ran the analysis. Sierra Club claims that the outside consultant cannot be independent because "FirstEnergy dictated the assumptions for the analysis."[893] This claim lacks any record support. While those conducting the study worked as a team, and Gavin Cunningham led the team, Sierra Club can point to no record evidence demonstrating that the Companies in any way "dictated" how the consultant ran the models, or somehow overruled the outside consultant's independent professional judgment. Plus, Sierra Club overlooks that the assumptions used were PJM's models. It is Sierra Club and other intervenors who are asking that PJM's models be ignored. The goal should not be to have an independent analysis, but to have an analysis that replicates PJM's results. Thus, the Companies used PJM's inputs, PJM's methodology and a former PJM employee to conduct the impact studies.

OMAEG further argues that the transmission impact study needed to be conducted by PJM.[894] This begs the question: why? The Companies have PJM's models and the expertise to study the load flows – the Companies do it "every year, hundreds of times with all those

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[889] OCC/NOAC Brief, pp. 123-124; OMAEG Brief, p. 32; Sierra Club Brief, p. 100.

[890] OMAEG Brief, p. 32.

[891] Hearing Tr. Vol. XV, pp. 3245-46 (Phillips Cross).

[892] Hearing Tr. Vol. XV, p. 3246 (Phillips Cross).

[893] Sierra Club Brief, p. 100.

[894] OMAEG Brief, p. 32.

studies."[895] In addition to obtaining the models from PJM, the Companies followed PJM's manual 14B process faithfully.[896] If PJM were to run the same studies, PJM would reach the same results.[897]

In addition, Sierra Club challenges the estimated 82% allocation of transmission costs to the Companies' customers.[898] Sierra Club contends that since the Companies did not consult PJM, and do not have the capability to do cost allocation themselves, the 82% assumption is nothing more than a guess.[899] Sierra Club maintains that the 82% the Companies' customers paid of the $1 billion in transmission upgrade costs associated with the Lake Plant retirements does not apply to different units at different locations, particularly because some of the most expensive violations identified by the transmission impact study are facilities located outside ATSI or Ohio.[900]

Sierra Club's attacks ignore the point of the Companies' estimated cost allocation. At this time, no actual cost allocation is possible. The actual allocation of costs will be unknown until after PJM identifies the necessary upgrades and does the allocation for those upgrades.[901] Because we do not know which specific upgrades – reconductoring, rebuilds and new builds – would be required, the Companies provided a "good reasonable" estimated allocation based on recent experience with plants closing in the ATSI zone – what Company witness Phillips called

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[895] Hearing Tr. Vol. XV, p. 3252 (Phillips Cross).

[896] Hearing Tr. Vol. XVI, pp. 3403-04, 3407 (Phillips Redirect).

[897] Hearing Tr. Vol. XV, pp. 3252-53 (Phillips Cross).

[898] Sierra Club Brief, pp. 96-99. *See* Phillips Supp., p. 10; Mikkelsen Second Supp., pp. 7-8.

[899] Sierra Club Brief, p. 97.

[900] Sierra Club Brief, pp. 96-99.

[901] Hearing Tr. Vol. XV, pp. 3237-39 (Phillips Cross); Hearing Tr. Vol. XVI, pp. 3320, 3321-22 (Phillips Cross).

the Lake Plants.[902] In the case of the Lake Plants, PJM allocated approximately 89% of the estimated $1 billion in costs to Ohio customers and approximately 82% of the costs to the Companies' customers.[903] In lieu of not having the actual costs that would result from the retirement of the Plants, which serve load in ATSI, Company witness Phillips reasonably used the Companies' recent experience with the 82% cost allocation resulting from very similar plants serving load in ATSI.[904]

e. **The Commission has jurisdiction over reliability.**

There can be little question that the continued operation of the Plants will contribute to reliable electric service.[905] Several opponents, however, contend that this is irrelevant to the Commission, and claim the reliability of Ohio's electricity grid is the exclusive concern of PJM and, consequently, the Commission somehow has no responsibility in this vein.[906] P4S goes further and claims that PJM's RPM construct ensures sufficient capacity resource products are available to maintain system reliability, and that the CP product further improves the design of the capacity market.[907] PJM's argument is more measured. PJM contends that it is responsible for reliability of the bulk electric system in the PJM Region which includes Ohio, as well as for ensuring resource adequacy and transmission security. PJM argues that it provides a foundation

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[902] Hearing Tr. Vol. XV, pp. 3238-39 (Phillips Cross); Hearing Tr. Vol. XVI, pp. 3320, 3336 (Phillips Cross); Phillips Supp., p. 10; Company Ex. 40 (Phillips Workpaper), pp. 4-5. *See* Hearing Tr. Vol. XXV, p. 5151 (Lanzalotta Cross) (Sierra Club witness Lanzalotta agreeing that it would be speculating to say today what combination of reconductoring, rebuilds and new builds would be required by PJM).

[903] Phillips Supp., p. 10.

[904] Hearing Tr. Vol. XVI, p. 3238 (Phillips Cross).

[905] Harden Direct, p. 9.

[906] *See* Exelon Brief, p. 29; OCC/NOAC Brief, p. 123 (generation reliability in a restructured state is within FERC's jurisdiction, not the Commission's); OMAEG Brief, p. 30; EPSA/P3 Brief, p. 25; P4S Brief, pp. 5-6; Sierra Club Brief, p. 101.

[907] P4S Brief, pp. 5-6.

at the wholesale level for reliable delivery of electricity, and that it manages the overall reserve margin through administration of a forward capacity market.[908]

Any suggestions that PJM has authority to plan generation projects are incorrect. At hearing, Mr. Phillips explained that PJM does not have the authority to direct the construction of generation, or to direct that generation be built in any specific location. All it can do is indicate where there are overloads and identify a transmission solution.[909]

Further, to the extent any of these parties claim the Commission, the State of Ohio, or the Companies, have no responsibility for keeping the lights on in the Companies' service territories, such claims are meritless. To the contrary, the Ohio General Assembly has declared: "It is the policy of this state to do the following throughout this state: (A) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service . . . ."[910] Also, the Commission's own statements affirm that it is, in fact, interested in, and justifiably concerned about, the reliability of Ohio's distribution system. The Commission has expressly recognized its responsibility to ensure the reliability of Ohio's distribution system, specifically through the preservation of fuel diversity such as that provided by the Plants. Indeed, the Commission publicly has stated:

> It is the responsibility of the PUCO to carry out the policy of the state of Ohio to ensure the diversity of electricity resources. The

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[908] PJM Brief, p. 9.

[909] Hearing Tr. Vol. XVI, p. 3329 (Phillips Cross).

[910] R.C. 4928.02(A). *See also* the Commission's Mission Statement, available at http://www.puco.ohio.gov/puco/index.cfm/how-the-puco-works-for-you/mission-and-commitments/#sthash.yx5tVnGC.dpbs ("Our mission is to assure all residential and business consumers access to adequate, safe and reliable utility services at fair prices, while facilitating an environment that provides competitive choices.").

> benefits of energy diversity to security, affordability, and reliability are well documented.[911]

Further, as OEC/EDF witness Roberto admitted, "The Public Utilities Commission needs to take into account the goals of the state of Ohio, and diversity and reliability of the supply are included in those goals."[912] Likewise, Mr. Scarpignato agreed under cross examination that "a state might also have an interest in reliability for its citizens."[913] Other intervenor witnesses, including PJM's independent market monitor, Dr. Bowring, made similar admissions. Dr. Bowring agreed that that supply diversity is an important factor for the Commission to consider when evaluating PPA rider proposals.[914] OCC/NOPEC witness Kahal admitted that the Commission has role to play in ensuring reliability for retail electric customers.[915]

5. Rider RRS satisfies the non-binding criteria set forth in the *AEP ESP3* Order.

As discussed in the Companies' Initial Brief, one the statutory basis for Rider RRS is found in Section 4928.143(B)(2)(d). Provided the Commission agrees that Rider RRS falls within the scope this provision and will provide stability benefits to customers, the Commission's review of Rider RRS should be complete. Nevertheless, in the *AEP ESP3* Order, the Commission set out additional non-binding criteria that it asked AEP to address in its PPA Rider application "to justify any requested cost recovery."[916] In this proceeding, however, the Companies are not seeking cost recovery. Instead, they are requesting approval of a retail rate stability mechanism that itself provides multiple benefits to customers. As such, the

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911 Comments On The U.S. EPA Carbon Paper Submitted On Behalf Of The Public Utilities Commission Of Ohio (Dec.16,2013) (available at http://www.naruc.org/ Publications/ Public%20Utilities%20Commission %20of%20Ohio.pdf) (quoted in Moul Direct, pp. 6-7) (emphasis added).

912 Hearing Tr. Vol. XXI, p. 4168 (Roberto Cross).

913 Hearing Tr. Vol. XXIV pp. 5110-11 (Scarpignato Cross).

914 Hearing Tr. Vol. XXIV, p. 5038 (Bowring Cross).

915 Hearing Tr. Vol. XXIV, p. 4894 (Kahal Cross).

916 *AEP* ESP3 Order, p. 25.

Commission need not consider the needs of the generating plants in order to approve Rider RRS. Nevertheless, because of the Commission's stated interest in the *AEP ESP3* Order factors, the Companies addressed each of the factors in supplemental testimony and in their Post-Hearing Brief.[917]

On balance, the *AEP ESP3* Order factors can be viewed as additional support for the Commission's determination that Rider RRS benefits customers and is in the public interest. As discussed below, intervenors' have failed to produce any credible basis for a contrary finding.

a. The Plants have financial need and their futures are uncertain.

Some intervenors argue that the Companies have not established financial need.[918] This is incorrect. Mr. Rose testified that unanticipated developments have lowered wholesale prices.[919] Mr. Moul testified that markets have not and are not providing sufficient revenues to ensure continued operation of plants.[920] This is shown through the historic profit and loss statements for the Plants, as well as the projections showing projected revenue is less than costs in near term.[921] No intervenor has been able to refute the simple truth established through the Company testimony, which is that these Plants are at risk of closure.[922] As Mr. Lisowski testified:

> Q. And why do you say [the plants are likely to close in the next] three or four years?
>
> A. It's primarily related to a couple factors. One is that FES' balance sheet is not strong at all. They're very limited in their abilities to take on any additional equity infusions. In fact, my personal opinion is I wouldn't

[917] *See* Mikkelsen Second Supp., pp. 2-14; Companies' Initial Brief, pp. 124-44.

[918] *E.g.,* Exelon Brief, pp. 48-49; NOPEC Brief, p. 34.

[919] Rose Direct, p. 4.

[920] Moul Direct, p. 3.

[921] Moul Supp., pp. 1-3; Ruberto Direct, Attachment JAR-1 (revised).

[922] *See, e.g.*, Lisowski Rebuttal

> expect FE Corp. to do that. I would expect FES not to be able to take on significant amounts of additional debt because of the fact of where FES' balance sheets are. So to the extent the next couple years pan out to be worse than even the projections show, FES may not be able to continue to withstand losses and negative cash flow to be able the get through. I say the next three to four years because both using Mr. Rose's projections as well as taking into consideration how the FES' internal projections show, I believe it's after the next two to three years when these plants seem to be much more financially sustainable.
>
> Q. So are you saying in your statement that FES overall is at risk?
>
> A. No, I don't believe that's what I said.
>
> Q. I'm sorry to interrupt. Go ahead.
>
> A. I believe what I said earlier is each plant needs to be able to financially stand on its own. It needs to be able to support itself. FES as a company may not be in the position to continue to subsidize one plant by taking on additional borrowings or abilities to get equity infusions in the future. So my testimony is not around FES Corp. as an entire company. My opinion is on these plants specifically and whether the owner of the plant is going to be able and willing to continue to borrow on its own balance sheet for these plants.[923]

Intervenors would have the Commission believe that there is no issue with the Plants. They say the Plants are recovering their avoidable costs.[924] They say that the Plants have already cleared the BRAs through 2019.[925] They say that the Plants could keep sufficient cash on hand to operate.[926] As shown below, each of these assumptions is either irrelevant or wrong.

(i) Covering avoidable costs does not ensure the Plants will remain open.

Some intervenors claim that the Plants ability to recover avoidable costs should be enough to ensure the Plants will not close.[927] They claim that FES will either continue to fund

[923] Hearing Tr. Vol. IX, pp. 1981-83 (Lisowski Cross).

[924] *See*, EPSA/P3 Brief, pp. 22-25.

[925] *See*¸Sierra Club Brief, pp. 88-89.

[926] *See*, EPSA/P3 Brief, pp. 22-25.

[927] Sierra Club Brief, pp. 88-89, 115; Exelon Brief, p. 23-24; Dynegy Brief, p. 8-9.

ongoing losses at the Plants in the near term, or that some mystery buyer will come forward to buy the Plants. The evidence is otherwise.[928]

Mr. Lisowski explained that simply recovering certain variable costs does not guarantee the Plants are economically viable.[929] Plants also need to recover necessary capital expenditures, accretion expense and interest expense, as well as any equity return or income tax expense.[930] The evidence is undisputed that the Plants have been unprofitable. From 2009 to 2014, the Plants [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[931] During the same period, the Plants [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[932] These results do not include interest costs or any return on investment.

Considering avoidable costs as the measure of financial viability fails to consider cash flow. As Mr. Lisowski explained, capital expenditures impact cash flow in the period incurred. For accounting purposes, these capital expenses may then be amortized over the useful life of the asset.[933] As such, a plant could be projected to be "profitable" in a year from an earnings perspective (because the full impact of the capital expense is not reflected on the profit and loss statements), but actually require its owner to invest hundreds of millions of dollars of cash for that same year.

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[928] Moul Supp., pp. 3-5; Moul Rebuttal, pp. 2-5; Lisowski Rebuttal, pp. 3-8.

[929] Lisowski Rebuttal, p. 2.

[930] Lisowski Rebuttal, p. 2-3.

[931] Moul Supp., pp. 2-3 and Exhibit JJL-7.

[932] Lisowski Rebuttal, p. 3.

[933] Lisowski Rebuttal, p. 4.

The evidence shows that FirstEnergy Corp. has had to contribute $2 billion in capital contributions for 2013 and 2014.[934] There is no evidence that either FirstEnergy Corp. or FES can continue on that path.

P4S argues that even if the near term cash flows at the Plants are negative, then FES could keep the Plants open with more than $500 million in cash on hand.[935] This is factually incorrect. Mr. Lisowski testified that "[a]lthough FES also had $525 million of Receivables from Affiliated Companies as of December 31, 2014, FES had Payables to Affiliated Companies of $416 million and Short-term Affiliated Company Borrowings of $35 million."[936] As a result, FES had only $2 million in cash and cash equivalents on hand as of December 31, 2014.[937] At hearing, Mr. Lisowski explained that FES did not have the free cash to keep the plants open indefinitely.[938]

> Q. Okay. And it's your position that at this point with no further capital infusions from FirstEnergy Corp. on the horizon, FES may have to instead retire Sammis and Davis-Besse because of the state of its balance sheet, correct?
>
> A. Yes. FE Corp. cannot provide any additional infusions into FES. Any time an infusion is made, there would be an expectation a return on and return of an investment, and since there's no -- there's a risk that is not going to be there, and the forecast in the near term doesn't show that, it's not clear that FE Corp. is going to be able to do that, in addition to FE Corp. has already provided that in the past as a means. So that's why that's no longer a possibility for FE Corp. to do that in the future.[939]

[934] OCC Ex. 32 (FirstEnergy Corp. 2014 10K), pp. 117-118.

[935] P4S Brief, p. 7.

[936] Lisowski Rebuttal, p. 8.

[937] Lisowski Rebuttal, p. 8.

[938] Hearing Tr. Vol. VIII, p. 1727 (Lisowski Cross).

[939] Hearing Tr. Vol. XXXIII, pp. 6814-15 (Lisowski Rebuttal Cross).

Because the Plants face significant challenges in the near term, and the FES balance sheet is not strong enough to fund cash flow concerns indefinitely, the Plants are at risk of closure.

Sierra Club argues that these short-term concerns are overstated because the Companies' current projections generally show positive cash flow in most years (with no return on equity and the inability to cover interest payments in some years).[940] Sierra Club's argument fails to account for the fact that there is uncertainty in the Companies projections, just like any other set of projections. Because the revenues and costs projected are not guaranteed there is a chance the Plants will close. As Mr. Moul testified:

> A. Well, let me start by saying Mr. Oliker's hypothetical provided me with certainty that I would be making a profit on these plants. My testimony is there is not a lot of the certainty in the marketplace today. If you don't continue to get a return on your investment, you don't have additional investment to improve or maintain the performance of these plants. As these plants would decline in performance, then you're challenging your energy revenue. Additional market prices going down could put us to the point where we're not recovering our avoidable costs, at which point we would be able to make a decision to deactivate the plants.[941]

Because the Companies do not have the certainty assumed in Sierra Club's hypothetical, there is no guarantee that the Plants will remain open under the Companies projections.

Of all the intervenor arguments that the Plants are not at risk, Sierra Club's are most lacking in conviction. Perhaps the strongest indication that the future of Sammis is uncertain is Sierra Club's extensive participation in this case. Sierra Club did not intervene because it is concerned with the Companies' customers, the stability of their rates, or whether their lights stay on. Sierra Club's narrow-minded fixation is on stopping anything it believes might lead to the continued operation of a coal plant, even a plant with tremendous investments in state-of-the-art

[940] Sierra Club Brief, p. 88.

[941] Hearing Tr. Vol. XI, pp. 2473-74 (Moul Redirect).

pollution controls like Sammis. Simply put, if "it is clear that the plants would not retire,"[942] as Sierra Club suggests, Sierra Club is not in this case.

(ii) Recent FES actions do not guarantee the Plants remain open.

Sierra Club argues that the Plants will not close in the near future because they have already cleared in the PJM capacity auctions through 2019.[943] While true, this does not guarantee that the Plants will remain open past 2019. Indeed, it also does not even guarantee that the Plants will remain open until 2019. FES could procure replacement capacity and retire the Plants.

OCC/NOAC argue that it would not make sense to retire the Plants right now because they have recently been upgraded or have been granted license extensions.[944] Mr. Lisowski provided concrete examples showing that past investments do not guarantee a plant will stay open in the future. He pointed out that in 2010 FES had changed the operations of several plants to address cash flow issues and later closed those plants. One of the plants which was closed was Hatfield's Ferry, a plant very similar to Sammis:

> Hatfield's Ferry is particularly relevant to this discussion since it shares many similarities with Sammis. Just like Sammis, Hatfield's Ferry had already invested in scrubbing technology. Also just like Sammis, Hatfield's Ferry had large supercritical units. These decisions were made because those plants had incurred past near-term losses and negative cash flow that were expected to continue in the near-term.[945]

As explained by Mr. Lisowski, past investments do not guarantee that plants will remain open.

[942] Sierra Club Brief, p. 81

[943] Sierra Club Brief, p. 89.

[944] OCC/NOAC Brief, p. 130.

[945] Lisowski Rebuttal, p. 6.

b. **The Plants are needed to ensure reliability.**

Various parties argue that the Plants are not needed to ensure reliability.[946] In so doing, the parties do little to dispute Mr. Moul's testimony regarding the stability and certainty provided by the Plants.[947] They do not dispute his testimony regarding the benefits of resource diversity. Nor do they credibly dispute Mr. Phillips testimony regarding the negative effects on reliability by having to address the retirement of the Plants through transmission additions.[948] Instead, these parties provide an array of weak responses: (1) that new generation will replace the Plants; (2) that PJM can deploy a Reliability Must Run ("RMR") arrangement; (3) that Mr. Phillips isn't a reliable witness because he wasn't up to date on something PJM said; or (4) that there's no need to worry about resource diversity because Ohio currently enjoys such diversity. As shown below, each of these arguments is belied by the record.

(i) The Plants are needed to ensure stability and certainty in the distribution system.

Exelon, EPSA/P3 and the Sierra Club argue that there is no cause for reliability concerns because the Plants are not going to close.[949] To the contrary, as demonstrated in the Companies' Initial Brief and above, the record shows the Plants face economic threats today, and FES "may not be able to continue incurring losses by continuing to run the Plants in the near term in order to incur the long-term benefits associated with the Plants."[950]

Some parties contend that the Plants are unnecessary because new natural gas plants under construction, and plants located throughout PJM, can replace the Plants.[951] However, only

[946] *See, e.g.,* OCC/NOAC Brief, pp. 65, 124; ELPC Brief, p. 25; NOPEC Brief, pp. 36-37.

[947] Strah Direct, pp. 7-10.

[948] Phillips Direct (Cunningham); Phillips Supp., pp. 7-10.

[949] Exelon Brief, p. 49; EPSA/P3 Brief, p. 25; Sierra Club Brief, p. 107.

[950] Moul Direct, pp. 3-4; Moul Supp., pp. 1-5.

[951] Exelon Brief, p. 29; NOPEC Brief, pp. 39-40; OCC/NOAC Brief, p. 126.

seven percent of the megawatts that enter the PJM queue gets built and goes into service.[952] Further, Company witness Phillips explained that increasing the distance between generation and load centers increases the potential for outages on the transmission system that affect reliability at the load center.[953]

Sierra Club challenges Mr. Phillips' concerns about the distance between generation sources and the Companies' load. Sierra Club points to Mr. Phillips' lack of familiarity with whether PJM has identified proximity as a concern and the fact that PJM maintains reliability regardless of proximity.[954] Mr. Phillips is an electrical engineer responsible for, among other things, overseeing the monitoring and operation of FirstEnergy's entire transmission system. Mr. Phillips' familiarity with PJM's concerns is irrelevant. Mr. Phillips's expert opinion is that the potential for an outage on the transmission system to occur increases as the distance between generation and load centers increases.[955] No one disputed that view. Sierra Club cites to nothing contesting the substantive validity of Mr. Phillip's opinion. Even Sierra Club's own witness Mr. Lanzalotta recognized the importance of the location of a generation facility, speculating that a new generating unit coming on-line "at an appropriate location" could reduce the impact of the Plants' retirement.[956] Mr. Lanzalotta agreed that the further away (electrically, not by distance) new generation would be sited in relation to the Sammis plant, the less impact such generation would have on potential overloads caused by Sammis' retirement.[957]

[952] Hearing Tr. Vol. XV, p. 3234 (Phillips Cross) and Sierra Club Ex. 58, 2014 PJM Interconnection Queue Statistics Update, p. 6.

[953] Phillips Supp., p. 6.

[954] Sierra Club Brief, p. 102.

[955] Phillips Supp., p. 6.

[956] Lanzalotta Supp., p. 6. Sierra Club admits that Mr. Lanzalotta did not study the impact of any specific generation being added to the PJM transmission grid to lend credence to this speculation, and did not identify any specific generating units that will be built in Ohio at an "appropriate location." Sierra Club Brief, p. 94-95.

[957] Hearing Tr. Vol. XXV, pp. 5147-5148 (Lanzalotta Cross).

(ii) RMR arrangements are not a viable alternative to Rider RRS

Exelon, EPSA/P3, OMAEG and Sierra Club argue that if the Plants' retirement poses some reliability issue, PJM's Reliability Must Run ("RMR") process can ensure future reliability while transmission upgrades are implemented.[958] There are a number of things wrong with this argument. As an initial matter, a retiring generator must accept an RMR contract (*i.e.*, it is voluntary). Further, an RMR contract is a stopgap measure; it is only in place until new transmission is constructed.[959] Additionally, an RMR contract does not support capital investments necessary to operate a plant effectively.[960] At hearing, Mr. Moul explained that in his experience with RMR, a plant does not earn a good return and its reliability degrades:

> And my experience with RMR has been with the Lake plants which was based on the PJM tariff under which there was an allowance for only $2 million in capital investment. So you end up having those plants limp along and really don't provide the same level of reliability that a plant that's earning a good return and getting reinvestment in it gets.[961]

Mr. Moul further explained that while the RMR process provides for some return, that return is only on the costs that are allowed by the Market Monitor.[962] Thus, an RMR contract is unlikely to provide sufficient financial incentive for the Plants to remain open.[963]

Notably, the parties resting on the reliability "virtues" of an RMR miss this salient point: an RMR arrangement does not spare customers from the costs of transmission upgrades needed

[958] Exelon Brief, p. 29; OMAEG Brief, p. 33; EPSA/P3 Brief, pp. 26-27; Sierra Club Brief, p. 101.

[959] Moul Supp. at 7.

[960] Moul Supp. at 7.

[961] Hearing Tr. Vol. XI, p. 2258 (Moul Cross).

[962] Hearing Tr. Vol. XI, p. 2260 (Moul Cross).

[963] Exelon notes that a generator has two options for RMR under the PJM tariff: an Avoidable Cost Recovery Rate, and a Cost of Service Recovery Rate. Exelon Brief, p. 29-30. Mr. Moul explained that both options are risky for generators under an RMR because they both could potentially require the generator to make further filings and subject itself to further review by FERC in order to achieve full cost recovery. Hearing Tr. Vol. XI, p. 2262-2265 (Moul Cross).

merely to maintain (and not improve) reliability. The new transmission built during the RMR arrangement will cost customers, while not providing the stability and economic benefits of preserving existing baseload generation like the Plants.[964] As Company witness Phillips explained, new transmission is no substitute for generation located in close proximity to load.[965] Thus, the potential for an RMR arrangement does little to assure reliability, when compared to the continued operation of the Plants.[966]

(iii) Resource diversity provides significant benefits to customers.

The Companies' Initial Brief explained at length that a proliferation of retirements of baseload coal and nuclear plants has left the market increasingly reliant on interruptible natural gas fueled generation.[967] The Companies further explained that this rapid trend, and the "dash to gas," creates a need to preserve generation resource diversity (in terms of both the fuel mix and asset class mix) through the continued operation of economically stressed baseload coal and nuclear plants with significant stores of on-site fuel supply.[968]

Some parties go out of their way to mischaracterize this important point. NOPEC and OMAEG argue that the primary fuel source in Ohio has been coal, and recite statistics from recent years, e.g., that in 2012 coal and natural gas represented 59% and 27% of generation capacity in Ohio, respectively.[969] These parties argue that continued operation of Sammis and the OVEC plants actually prevents fuel diversity; *i.e.*, that such diversity would be promoted by

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[964] Moul Supp., p. 7-8.

[965] Moul Supp., p. 7; see also Phillips Direct, p. 6.

[966] Moul Supp., p. 7.

[967] Companies' Brief, p. 5.

[968] Companies' Brief, pp. 24-27, 55-67, 128-131.

[969] NOPEC Brief, p. 35; OMAEG Brief, p. 34.

replacing Sammis and OVEC with natural gas plants.[970] Sierra Club argues that the generation mix in Ohio, as recently as 2014, was 80% coal and nuclear, contending that the retirement of Sammis will make no dent in Ohio's generation mix.[971]

Contrary to what these parties suggest, the Companies are not focused on where Ohio's generation mix was, or even where it is today. The critical issues are what will that generation mix be over the next several years and how will that mix effect customers. As Company witness Moul made clear, the consequences of overreliance on a single class of generation, such as natural gas, can be dire.[972] The trend towards a gas-reliant generation mix is undisputed. Several witnesses recognized at hearing that the vast majority of recent retirements occurring in PJM has been coal-fired generation.[973] And gas-fired units constitute the overwhelming percentage of recent generation additions in PJM.[974] In short, PJM is experiencing a significant shift toward natural gas resources. These new resources are neither intended nor designed to replace baseload coal and nuclear units, thus creating a serious and legitimate reliability risk.[975] The fact is, maintaining nuclear and coal baseload plants located close to load is crucial to preserve an efficient mix and reliability during a transition to more natural gas generation supported by adequate pipeline infrastructure.[976] Because reliability issues will persist as baseload coal and nuclear plants are retired across PJM, ensuring "the continued operation of

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[970] NOPEC Brief, p. 36; OMAEG Brief, p. 34.

[971] Sierra Club Brief, pp. 108-109.

[972] Moul Direct, pp. 7-8.

[973] *See* Hearing Tr. Vol. XXIV, p. 4874 (Kahal Cross); Hearing Tr. Vol. XXIV, pp. 5016-17 (Bowring Cross); Hearing Tr. Vol. XXIV, p. 5101 (Scarpignato Cross); Hearing Tr. Vol. XXII, p. 4574 (Wilson Cross).

[974] Hearing Tr. Vol. XXIV, p. 4875 (Kahal Cross); Hearing Tr. Vol. XXIV, p. 5017 (Bowring Cross); Hearing Tr. Vol. XXIV, p. 5101 (Scarpignato Cross); Hearing Tr. Vol. XXII, pp. 4574-74 (Wilson Cross).

[975] Strah Direct, p. 8.

[976] See Moul Direct, p. 10; Moul Supp., p. 8.

baseload generating units that are fuel diverse with onsite fuel storage capabilities" – such as the Plants – remains vital.[977]

EPSA/P3 witness Dr. Kalt also recognized the significant shift in generation resources already underway in PJM. He agreed that PJM is a net importer of power.[978] He further agreed that the largest share of baseload generation is coal-fired and that the largest share of cycling plants are gas-fired.[979]

The Commission publicly has expressed concern about this trend, i.e., "the dash to gas," and its potential to negatively impact reliability in Ohio:

> The 'dash to gas' scenario causes concern to economic regulators because the more dependent a system is on one specific fuel type, the more risk and volatility there exists for [customers].[980]

And further:

> [A] significant portion of the retiring megawatts being replaced by natural gas resources, we cannot afford to forget about protecting our current resources that help in hedging against any unforeseen natural gas curtailments.[981]

The Companies' Initial Brief explained how the reliability risk of replacing baseload coal and nuclear plants with natural gas plants was demonstrated by the 2014 Polar Vortex and the 2015 Siberian Express, when gas-fired plants accounted for a disproportionate number of total

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[977] Hearing Tr. Vol. I, p. 96 (Mikkelsen Cross).

[978] Hearing Tr. Vol. XXVIII, p. 5634 (Kalt Cross).

[979] Hearing Tr. Vol. XXVIII, pp. 5634-35 (Kalt Cross).

[980] Comments Submitted on Behalf of the Public Utilities Commission of Ohio, p. 8, Technical Conference on Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators, FERC Docket No. AD14-8-000 (May 15, 2014) (quoted in Moul Direct, p. 9).

[981] Comments Submitted on Behalf of the Public Utilities Commission of Ohio, pp. 7-8, Technical Conference on Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators, FERC Docket No. AD14-8-000 (May 15, 2014) (quoted in Moul Direct, pp. 7-8).

forced outages.[982] Sierra Club and NOPEC contend that the Companies overstate their claims that the reliability of coal and nuclear is superior to that of natural gas.[983] According to these parties, coal plants have reliability problems too.[984]

The outage events during the 2014 Polar Vortex and the 2015 Siberian Express demonstrate why the Commission should be concerned. In its report on the Polar Vortex, PJM noted:

> …[N]atural-gas-fired generators accounted for 47 percent of the unavailable megawatts…[F]or a frame of reference, in PJM, gas-fired plants represent 29 percent of total generation (in megawatts), and coal-fired plants 41 percent.[985]

Interruptions caused by, and outages of, gas-fired generation thus were disproportionate to the quantity of natural gas generation that comprises the PJM generation mix. Several intervenor witnesses to this proceeding, including EPSA/P3 witness Kalt, OCC/NOPEC witness Wilson and RESA witness Scarpignato, admitted the same during cross examination at hearing.[986]

NOPEC argues that PJM made system improvements following the Polar Vortex, resulting in better performance by generators, despite colder temperatures and greater demand.[987] However, NOPEC omits to mention that PJM, in its 2015 Winter Report, once again found that

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982 The record illustrates that many gas plants were unable to operate during the extreme cold spell of the Polar Vortex. *See* Strah Direct, p. 8; Hearing Tr. Vol. IV, pp. 875; 762-63; 762 (Strah Cross); Hearing Tr. Vol. VII, p. 1509 (Rose Cross). PJM's report on the Polar Vortex specifically noted that interruptions caused by, and outages of, gas-fired generation were disproportionate to the quantity of natural gas generation that comprises the PJM generation mix. Sierra Club Ex. 8, p. 25. And, with respect to the 2015 Siberian Express, PJM again found that gas-fired units were disproportionately responsible for forced outages. IGS Ex. 1, p. 6.

983 Sierra Club Brief, pp. 107-110; NOPEC Brief, p. 38.

984 Sierra Club Brief, pp. 109-110; NOPEC Brief, p. 38.

985 Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events, PJM Interconnection (May 8, 2014), p. 25 (Sierra Club Ex. 8).

986 Hearing Tr. Vol. XXIV, pp. 5101-02 (Scarpignato Cross) (admitting disproportionate contribution of gas-fired generation to reliability issues during 2014 Polar Vortex); Hearing Tr. Vol. XXII, p. 4575 (Wilson Cross) (admitting same); Hearing Tr. Vol. XXVIII, pp. 5638-39 (Kalt Cross) (admitting same).

987 NOPEC Brief, pp. 38-39.

gas-fired units were disproportionately responsible for the forced outages that occurred during the Siberian Express:

> Despite more natural gas, LNG and storage, there were just as many, if not more, restrictions issued by the pipelines… On the morning of Feb. 20, forced outages from gas totaled 7,420 MW, or 29.9 percent of total forced outages. In comparison, at the Jan. 7, 2014, peak, 9,300 MW of gas-fired capacity was out of service because of natural gas unavailability, or about 25 percent of the total outages.[988]

As a percentage of total outage caused by interruptions perspective, natural gas-fired generation fared *worse* in 2015 as compared to 2014.[989] In contrast, baseload nuclear and coal-fired plants with onsite-fuel supplies, like the Plants, ran relatively reliably during the winters of 2014 and 2015.[990]

Sierra Club argues that PJM treats natural gas plants with firm deliverability as CP products, the same as coal or nuclear.[991] Thus, Sierra Club implies the reliability of natural gas plants is much improved. While Sierra Club emphasizes Company witness Moul's recognition at hearing that a natural gas power plant with firm pipeline transportation and a long-term supply contract *can* operate as reliable baseload generation, Mr. Moul explained at hearing that this

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[988] 2015 Winter Report, PJM Interconnection (May 13, 2015), p. 6 (IGS Ex. 1). *See also* IGS Ex. 1, p. 22, Figures 21 and 22 (showing that 30% of forced outages on February 20, 2015 were due to natural gas while 24% of forced outages were due to natural gas on January 7, 2014). The report noted some small incremental improvements between 2014 and 2015, but as the 2015 outage rate for gas demonstrates the underlying reliability issues were not alleviated. IGS Ex. 1, p. 5. Indeed, PJM noted that such improvements were "short-term" and the recent CP product was deemed "inadequate" as a "long-term solution." IGS Ex. 1, p. 6.

[989] Indeed, as Mr. Rose testified at hearing, "Furthermore, when you look at the gas versus the coal outages [for 2015], take a look at the denominator, not just the numerator. There is, as I indicated, more total outages for gas plants over less gas plants. They should have had much less. In fact, they had more." Hearing Tr. Vol. VII, p. 1509 (Rose Cross).

[990] Hearing Tr. Vol. X, p. 2195 (Moul Cross); Hearing Tr. Vol. XI, p. 2255 (Moul Cross). Further, as coal and nuclear retirements accelerate, there is no guarantee that the gas generation projects currently in the PJM generation queue will even come online. "Of the projects that have completed the queue process, 87.6 percent of the MW that entered the queue withdrew at some point in the process." Company Ex. 76 (State of the Market Report for PJM Q2 2015), p. 397. *See also* Company Ex. 75 (State of the Market Report for PJM Q1 2014), p. 361 ("The queue contains a substantial number of projects that are not likely to be built.").

[991] Sierra Club Brief, pp. 109-110.

often does not happen in practice during an emergency event. Mr. Moul testified that during the winter of 2015, about 30% of natural gas plants were unable to get their gas supply during emergencies:

> Q. Okay. And if a natural gas power plant procures firm pipeline transportation and enters into a long-term contract for its fuel, it can operate as reliable baseload generation, correct?
>
> A. I would disagree. When I look at, for example, the 2015 PJM winter report, I see gas interruptions during those emergency times of about 30 percent of natural gas plants being unable to get their gas supply. And while some of them were behind the local distribution company, the LDC, there's a fair number of those that were on the interstate pipeline with day-ahead reserves. So by its very nature, just because you have a contract doesn't mean the contract can't be breached.
>
> Additionally, a pipeline typically doesn't have the defense and depth that an electric grid or transmission system does. There is one pipeline coming to a plant, so a mechanical failure anywhere on that system could render that plant incapable of performing and expose it to potential penalties.[992]

In short, contract rights for firm natural gas delivery are no substitute for the "bird in the hand" provided by significant stores of on-site fuel supply.

Sierra Club also asserts that the Companies improperly discount other resources, such as wind, energy efficiency and demand response.[993] However, Company witness Moul explained at hearing why wind, while an important part of any balanced generation fuel mix, was not included in the package of resources offered to the Companies:

> [W]hen we're looking at 24/7 capability, fuel controlled on site, up to two years at Davis-Besse and 30 days at Sammis, those are the kind of reliability benefits and certainty of the ability to generate that we put forth as a value for the companies' customers. Wind by

[992] Hearing Tr. Vol. X, pp. 2215-16 (Moul Cross).

[993] Sierra Club Brief, p. 111.

> its very intermittent nature can't provide those same certain generation outputs and consistent potential revenues.[994]

Further, while wind outperformed expectations during the Polar Vortex, it is only two percent of the generation stack and the lion's share of reliable power during the emergency was provided by coal and nuclear units.[995]

Sierra Club also attacks Company witness Makovich, challenging his testimony regarding the value of resource diversity. They argue that he has little knowledge of the Plants, the proposed transaction, or Rider RRS.[996] This is a red hearing, however, since Dr. Makovich's study of the benefits of resource diversity did not rely on any specific information about the Plants.

OCC/NOAC contend that fuel diversity is the responsibility of PJM and NERC, not the Companies.[997] The PJM Independent Market Monitor would disagree. At hearing, Dr. Bowring agreed that supply diversity is an appropriate factor for the Commission to consider in evaluating proposals like Rider RRS.[998]

c. **The Plants comply with environmental regulations.**

NOPEC, Sierra Club, OCC/NOAC and EDF offer conclusory claims that the Plants have not established that they will comply with environmental regulations.[999] The intervenors do not argue that the Plants are not currently in compliance, but instead argue that there are potential future regulations which could affect the Plants. As discussed in the Companies Initial Brief at pages 131-40 and above in Section III.A.1.d.iv., Mr. Evans and Mr. Harden explained that the

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[994] Hearing Tr. Vol. XI, p. 2401 (Moul Cross).

[995] Hearing Tr. Vol. XI, p. 2402 (Moul Cross).

[996] Sierra Club Brief, pp. 112-113.

[997] OCC/NOAC Brief, p. 127.

[998] Hearing Tr. Vol. XXIV, p. 5038 (Bowring Cross).

[999] NOPEC Brief, p. 40-41; Sierra Club Brief, p. 117; OCC/NOAC Brief, p. 127.

Plants are compliant with all existing and planned environmental requirements.[1000] Mr. Lisowski also included costs in his projections for both known and potential future environmental regulations, and so this prong has been met.

d. **The proposed transaction includes rigorous Commission oversight and full information sharing.**

Some intervenors argue that Rider RRS does not anticipate rigorous commission oversight and full information sharing.[1001] This issue was addressed in the Companies' Initial Brief at pages 73-76 and in Section III.A.3.e. above.

e. **Closing the Plants would negatively impact electric prices and retail rate stability, with a resulting negative impact on economic development.**

As addressed in detail in the Companies' Initial Brief, the Plants have a positive impact on electric prices and retail rate stability, and the resulting impact on rates if they were closed would cause negative economic impacts.[1002] If the Plants were closed, customers would be exposed to the risk of higher and more volatile natural gas prices in the future.[1003] Additionally, if the Plants close, the Company's customers risk being held responsible for paying between $1.7 and $4.1 billion for transmission upgrades.[1004] Those risks are a threat to economic development.[1005]

In addition, the Plants offer significant economic benefits. Ms. Murley found that Sammis' retirement would cause a severe blow to the economies of the three-state region where

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[1000] Harden Direct, pp. 9-12; Evans Supp. (all); Evans Rebuttal (all).

[1001] Bennett Supp. Direct, p. 3.

[1002] Companies' Initial Brief, pp. 140-44.

[1003] Moul Direct, pp. 6-10; Makovich Supp., pp. 3-4; Hearing Tr. Vol. III, p. 515 (Mikkelsen Cross); Hearing Tr. Vol. XI, p. 2255 (Moul Cross); Hearing Tr. Vol. XXV, p. 4941-42 (Haugen Cross).

[1004] Phillips Supp., pp. 6-10; Mikkelsen Second Supp., pp. 6-11 and Attachment EMM-2.

[1005] Strah Direct, p. 11; Hearing Tr. Vol. IV, pp. 877-78, 796 (Strah Cross). *See* Rose Direct, p. 8.

it is located. 482 jobs at Sammis would be lost, and additional indirect and induced jobs would be lost in the region.[1006] Closing Sammis would result in $602.2 million in lost economic activity in the seven-county region surrounding Sammis.[1007] Similarly, closing Davis-Besse would result in the loss of an estimated 675 direct jobs and 911 indirect and induced jobs at establishments that do business with Davis-Besse and its employees,[1008] $338.0 million/year in direct output, and an additional $131.2 million in indirect and induced output each year. [1009]

No intervenor witness presented their own competing analysis of the impact on rates and resulting economic impact were the Plants to close. That is extraordinarily telling, given that the Commission specifically identified the negative impact on electric prices, and the negative economic impacts that would result, as one of the factors it would consider in evaluating PPA-type riders. This silence is evidence that Ms. Murley selected a widely accepted model and applied it appropriately. With that said, a few intervenors made passing comments about Ms. Murley's analysis, and each of those comments is addressed and refuted below.

(i) Company Witness Murley's analysis conservatively demonstrated the benefits of Rider RRS.

Some intervenors have alleged that Ms. Murley's economic impact analysis is flawed because it does not incorporate the alleged costs of Rider RRS. Specifically, those intervenors allege that Rider RRS would raise customer prices, causing a corresponding decrease in economic activity. [1010] Those intervenor criticisms are wrong because Rider RRS is projected to have the net effect of lowering customer prices, not raising them. Therefore, Ms. Murley's

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[1006] Murley Supp., p. 6; Hearing Tr. Vol. XV, pp. 3114-3115 (Murley Cross).

[1007] Murley Supp., p. 6; Hearing Tr. Vol. XV, pp. 3214-3216 (Murley Cross).

[1008] Murley Supp., p. 10.

[1010] Sierra Club Brief, p. 104 (should have taken into account chance of higher prices associated with Rider RRS); OCC Brief, p. 129 (same); NOPEC Brief, p. 42 (same); ELPC Brief, p. 43 (same); OMAEG Brief, p. 42 (same).

assumption not to take into account the economic impact of lower prices was a conservative assumption which understated the economic impact of the Plants. Even intervenor witnesses, such as OCC witness Rose, admit that if Rider RRS lowers customer prices that would be a positive thing for economic development.[1011] As such, not including Rider RRS in Ms. Murley's analysis was a conservative assumption since it decreased the total economic benefit.

Sierra Club argues that Ms. Murley's analysis is flawed because she should have verified the location of expenditures as projected by IMPLAN, such as whether the Sammis plant purchased the amount of office supplies in the region as IMPLAN projected it would.[1012] This argument evidences a fundamental misunderstanding of how economic impact analysis works. There is no way to verify the specific location of each economic impact in the economy. Verifying just the "office supply" impact would require knowledge about where Sammis purchased its office supplies, where that office supply company purchased its inventory, where that inventory was manufactured, where the employees of the office supply company work and reside, etc.[1013] As Ms. Murley explained at hearing, economic impact analysis relies on the assumptions in the widely used IMPLAN model to make those determinations, which includes specific assumptions for each of hundreds of products.

> Q. And do you know what the IMPLAN assumes the percentage is for the services provided in Ohio?
>
> A. There could be hundreds of different purchases, and there are different percentages for each.

[1011] Hearing Tr. Vol. XXVI, p. 5389 (Hill Cross) ("Q. And you would agree that if the Commission believes that prices would be lower over the long-term by approving proposed rider RRS, that those lower prices would have a positive impact on economic development, correct? A. If they were correct. Q. Is that a yes? A. Yes, given your assumption.")

[1012] Sierra Club Brief, pp. 105-106.

[1013] *See*, *e.g.*, Hearing Tr. Vol. XV, p. 3109 (Murley Cross) ("A. That's correct, because of the inherent difficulties in getting the data and exactly situations like you identified where there may be a principal place of business in one location but the good or service is produced in another location.")

> Q. So are you suggesting that the IMPLAN model doesn't have a set percentage for each type of service?
>
> A. I'm suggesting that it does have a percentage for each type of good or service. [1014]

Moreover, it is not appropriate to look at only one type of purchase manually and rely on the model for the remainder. It is accordingly the widely used industry practice (including use by numerous government agencies at the federal and state level, including the Ohio Department of Development) is to rely solely on IMPLAN without verification of specific inputs. Sierra Club's argument to the contrary is not supported by any evidence or industry practice and should be rejected.

(ii) The decommissioning process would provide only a minor economic impact.

NOPEC argues that Ms. Murley failed to consider the economic impact that decommissioning could have on economic impact. [1015] NOPEC apparently failed to read Ms. Murley's supplemental testimony, which specifically addresses this point. "I present calculations showing the economic impact which would be lost if the Plants retired."[1016]

Compounding its error, NOPEC argues that decommissioning would be an "enormous undertaking" causing a huge economic impact associated with the closure of the Plants.[1017] Once again NOPEC ignores the evidence. With regard to the Sammis plant, Ms. Murley found that there are almost no decommissioning costs.[1018] As coal plants retire quickly, almost all economic activity associated with the Plant would be gone immediately. The analysis for the Davis-Besse facility was very similar. While closing a nuclear unit takes longer than closing a

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[1014] Hearing Tr. Vol. XV, p. 3108 (Murley Cross).

[1015] NOPEC Brief, p. 41.

[1016] Murley Supp., p. 2.

[1017] NOPEC Brief, p. 42.

[1018] Murley Supp., p. 6.

coal plant, substantially all work at the facility stops in short order. Ms. Murley provided a table in her testimony which shows that substantially all economic output at the Davis-Besse Facility is lost within 6 months.[1019]

In addition, Ms. Murley's calculations are conservative since they fail to address long-term impacts that closing the Plants could have.

> Over the longer term economies and employees adjust to the types of shocks created by the retirement of facilities like the Sammis plant. Although some employees who lose their jobs will seek other jobs within the region, others move out of the region or the state to find suitable employment. As this out-migration occurs, the overall size of the regional economy shrinks. Thus, the negative impact of closing a plant could possibly be higher than the positive impact of the plant's on-going operations. For example, if a Sammis employee moves out of the area to find work their spouse may move with them, thereby also removing the spouse's economic activity. Under this hypothetical, the closure of the Sammis plant leads to the loss of more than 100% of the economic activity at Sammis. My analysis does not take these long-term impacts into account and is therefore as I state above a conservative estimate.[1020]

Taken as a whole, this shows that the decommissioning process does not have any substantial impact on Ms. Murley's calculations.

(iii) Economic development analysis should not assume hypothetical new plants will be constructed.

Several intervenors claim that the Plants may be replaced by new capacity, and therefore no economic development analysis is needed.[1021] OCC/NOPEC witness Sioshansi asserted a similar argument, claiming that an economic development analysis requires all impacts, including potential new plants, be considered.[1022] On cross examination, Dr. Sioshansi admitted

[1019] Murley Supp., p. 10.

[1020] Murley Supp., p. 7.

[1021] Sierra Club Brief, p. 107; OCC Brief, p. 129; OMAEG Brief, p. 41.

[1022] Hearing Tr. Vol. XXII, p. 4471 (Sioshansi cross).

that he had not done that analysis.[1023] He also admitted that no other witness in this proceeding other than Ms. Murley had quantified the economic impact of the plants retiring.[1024]

Ms. Murley explained the error in that argument at hearing, observing that it was unlikely that the new plants would be built in the same locations as the Plants.[1025] Ms. Murley also pointed out that calculating the economic benefits of new capacity was impossible, because the timing and location of new generation was unknown.[1026] Accordingly, it would not have been possible or appropriate for Ms. Murley's analysis to assume that hypothetical new facilities would be constructed.

f. **Stipulated ESP IV and the proposed transaction reasonably allocate financial risks.**

Some intervenors argue that financial risk has been inappropriately allocated to customers.[1027] The benefits of Rider RRS were addressed in Section III.A.3. above. Specific to the AEP Ohio factors, the intervenors argue that the Companies' agreement in the Third Supplemental Stipulation to provide up to $100 million in credits to customers is not sufficient. They argue that this credit does not guarantee that customers will receive a net credit over the term of Rider RRS. Indeed, CMSD argues that customers should be exposed to no risk whatsoever.[1028] As discussed above, that is the nature of a hedge. There is no need to "guarantee" results for customers under a hedge.

[1023] Hearing Tr. Vol. XXII, p. 4473 (Sioshansi cross).

[1024] Hearing Tr. Vol. XXII, p. 4473 (Sioshansi cross).

[1025] Hearing Tr. Vol. XV, p. 3079 (Murley cross).

[1026] Hearing Tr. Vol. XV, p. 3079 (Murley cross).

[1027] Sierra Club Brief, p. 118; EPSA/P3 Brief, pp. 29-30; Exelon Brief, pp. 52-53; NOPEC Brief, p. 45; CMSD Brief, p. 38.

[1028] CMSD Brief, p. 38.

Sierra Club also argues that no risk has been allocated to FES, and that decision making would be improved if FES had a direct stake in the performance of the Plants.[1029] This is incorrect. As discussed above, under the Final Term Sheet FES is required to operate the Plants pursuant to Good Utility Practice or suffer financial consequences that may result by conduct to the contrary. Moreover, FES is exposed to the risk of not being able to recover market prices, an exposure currently project to be $561 million.

More importantly, the question is not what risks FES has. The question is what is the allocation of risk between Companies (the Applicants) and their customers. Here, as explained in the Companies' Initial Brief, the Companies are subject to an extensive audit process that will determine the reasonableness of the charges assessed under Rider RRS.[1030] The Companies have also agreed to provide up to $100 million in credits to benefit customers.[1031] Accordingly, there is significant risk sharing with customers.

g. Stipulated ESP IV contains a severability provision relating to the future approval or rejection of Rider RRS.

Some intervenors argue that the Third Supplemental Stipulation does not include an appropriate severability provision.[1032] The Third Supplemental Stipulation specifically includes a severability provision.[1033] As Ms. Mikkelsen explained, the severability provision would be triggered if any or all of Rider RRS was rejected by a court of competent jurisdiction.[1034] In that event:

[1029] Sierra Club Brief, p. 62.

[1030] Companies' Initial Brief, p. 74.

[1031] Companies' Initial Brief, pp. 74-76.

[1032] Cleveland Brief, p. 8; EPSA/P3 Brief, p. 30; Exelon Brief, p. 56; OMAEG Brief, p. 51.

[1033] Third Supp. Stip., Section V.B.3.c; Company Ex. 9, pp. 12-14.

[1034] Mikkelsen Second Supp., p. 13.

> [T]he Companies proposal would require the Signatory Parties to work in good faith and on an expedited basis, not to exceed 60 days, to cure any court determined deficiency. The Companies would then file (or jointly file with Signatory Parties) the modified Rider RRS, or its successor provision, with the Commission for expedited approval, and such approval shall not be withheld if the modified Rider RRS, or its successor provision, provides a reasonable remedy to cure the deficiency. During this process, the ESP IV would either remain in effect or, depending on timing, go into effect including all the agreed upon stipulated provisions, consistent with the Commission's prior approval of the ESP IV.[1035]

As Ms. Mikkelsen explained, the Companies have appropriately addressed the potential severability issue.

CMSD takes issue with the Companies authority to terminate the ESP if Rider RRS is invalidated.[1036] This is a statutory grant of authority under Section 4928.143(C)(2), not a part of Rider RRS. Rider RRS is an essential part of the deal struck by the Stipulating Parties. There is no reason to ask the Companies to waive their statutory rights in association with this or any other provision of the ESP.

Exelon claims that the severability provision improperly binds a future Commission.[1037] That argument does not make sense because literally any proceeding which anticipates future Commission action or approval would trigger this Exelon-created standard. Moreover, this provision does not seek to bind any future Commission. Instead, the provision expressly anticipates that the Commission will determine whether the remedy proposed is "reasonable." That by definition will require a determination by the future Commission, and does not bind that Commission. Exelon cites nothing in support of this theory. Therefore, it should be given no weight by the Commission.

[1035] Mikkelsen Second Supp. , p. 13.

[1036] CMSD Brief, p. 43.

[1037] Exelon Brief, p. 55.

h. The Commission should reject calls to consider additional factors.

OCC/NOAC argue that the nine additional factors identified by OCC/NOPEC witness Sioshansi are more appropriate than the factors created by the Commission.[1038] These arguments should be rejected because the Commission has already considered what are the appropriate factors to consider. The Commission does not need unsupported testimony from a witness who, in Dr. Sioshansi's case, does not even understand the market.

At a high level, OCC/NOAC's primary argument is that the Commission consider whether this transaction is in the best interests of customers.[1039] As that is already one purpose of the Commission's test, Dr. Sioshansi's true purpose is found in the additional ways he proposes that customer best interest must be determined. He proposes nine different criteria which he claims should be met before Rider RRS could be approved.[1040] These proposals range from unnecessary (hiring a Commission approved consultant) to beyond the jurisdiction of the Commission (dictating how the Companies will bid into the PJM markets). Regardless of the respective merits of the proposals Dr. Sioshansi invented, the Commission has already ruled on this issue. There is no need to create an entirely new standard based on the unsupported opinion of Dr. Sioshansi.

Some of the issues with Dr. Sioshansi's testimony could be explained from his lack of experience. Though Dr. Sioshansi claims 16 years of experience in the electric industry, he starts that time from his sophomore year of college and counts all of his time in undergraduate and graduate school towards that total.[1041] His only consulting work for a market participant took

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[1038] OCC/NOAC Brief, p. 135-45.

[1039] OCC/NOAC Brief, p. 136-137.

[1040] OCC/NOAC Brief, p. 135-45.

[1041] Hearing Tr. Vol. XXII, p. 4417 (Sioshansi Cross).

place in 2006 and 2007 for Pacific Gas and Electric relating to the California ISO.[1042] Though he claims expertise in renewable resources, his only experience is with solar thermal generation in California ISO.[1043] Dr. Sioshansi did not know whether solar resources are subsidized in Ohio or whether wind resources receive federal subsidies.[1044] He has never sold energy, has never read the FERC or PJM rules governing the sale of energy, and was almost completely unfamiliar with the market.[1045] Dr. Sioshansi did not know for certain whether regulated generation participates in the PJM market or has different bidding rules than unregulated generation.[1046] None of his work experience addresses the PJM capacity market, he has never read the rules regarding the PJM capacity market, and was unfamiliar with how the market operates. [1047]

While his lack of knowledge of the industry is troubling, more troubling was his lack of understanding about this proposal. Dr. Sioshansi had not even bothered to read the term sheet with the proposal he criticizes.[1048] He also testified (wrongly) that “staff would not have access to -- access to and the ability to audit FES's costs.”[1049]

In light of Dr. Sioshansi’s lack of knowledge regarding the electricity market and the Companies proposal, his suggestion to replace the Commission’s considered standard with one of his own devising is of little value.

[1042] Hearing Tr. Vol. XXII, pp. 4421-22 (Sioshansi Cross).

[1043] Hearing Tr. Vol. XXII, pp. 4423, 4426 (Sioshansi Cross).

[1044] Hearing Tr. Vol. XXII, p. 4435 (Sioshansi Cross).

[1045] Hearing Tr. Vol. XXII, pp. 4438-40 (Sioshansi Cross).

[1046] Hearing Tr. Vol. XXII, p. 4446 (Sioshansi Cross).

[1047] Hearing Tr. Vol. XXII, pp. 4449-52 (Sioshansi Cross).

[1048] Hearing Tr. Vol. XXII, p. 4455 (Sioshansi Cross).

[1049] Hearing Tr. Vol. XXII, p. 4455 (Sioshansi Cross).

B. Rider DCR As Proposed In Stipulated ESP IV Should Be Approved.

Rider DCR benefits customers by promoting system reliability.[1050] Indeed, it is undisputed that since Rider DCR has been in effect, the Companies have consistently outperformed their reliability standards.[1051] Under Stipulated ESP IV, the annual aggregate revenue recovery caps increase by $30 million during the first three years, drop to $20 million for years four, five and six, and then drop to $15 million for years seven and eight.[1052] The initial $30 million annual aggregate revenue cap increase is based on the *actual* average annual Rider DCR revenue requirement increase since the Companies last base rate case in 2007.[1053]

OCC/NOAC and OMAEG oppose Rider DCR as proposed in Stipulated ESP IV.[1054] These parties contend: (1) the rider is unnecessary because the Companies are earning excessive returns; (2) the rider violates "important regulatory principles" or is contrary to "sound ratemaking practice"; and (3) the Companies have not shown the alignment of the Companies' reliability performance with customers' expectations regarding reliability. Each of these arguments is belied by the record.

The first contention is based on rate of return and return on equity calculations by OCC witness Effron.[1055] Mr. Effron, however, admits that he is not a rate-of-return expert or an expert on what might be an adequate rate of return.[1056] Indeed, his calculation is further proof of his lack of expertise. The record shows that Mr. Effron's calculations are of a method of his own

[1050] Mikkelsen Direct, p. 8; Hearing Tr. Vol. XX, pp. 3927-28 (Company witness Fanelli describing benefits to customers arising from Rider DCR).

[1051] Mikkelsen Direct, pp. 9-10; Hearing Tr. Vol II, p. 252 (Mikkelsen Cross); Nicodemus Direct, pp. 9-10.

[1052] Third Supp. Stip., Section V.G.2.

[1053] Fanelli Direct, pp. 3-4; Hearing Tr. Vol. XX, pp. 3955-58 (Fanelli Cross).

[1054] OCC/NOAC Brief, p. 167; OMAEG Brief, p. 13; Effron Direct, pp. 9-19; Kahal Second Supp., pp. 24-25.

[1055] Effron Direct, pp. 9-19 and Schedule DJE-1.

[1056] Hearing Tr. Vol. XXI, p. 4097 (Effron Cross).

making to create a desired outcome. Mr. Effron admitted that his calculation did not use the Significantly Excessive Earnings Test ("SEET") formula.[1057] This is notable given that he understood that the SEET formula was established by the General Assembly for testing excessive earnings arising from the provisions of an ESP.[1058] (The Companies have never been found to have significantly excessive earnings).[1059] Mr. Effron's willful blindness to the proper criteria to review the Companies' earnings arising from an ESP extended to his failure to know whether the Companies have ever been found to have exceeded their Significantly Excessive Earnings Threshold.[1060]

The fact that Mr. Effron eschewed using the SEET formula should be the end of the story. The General Assembly has spoken. It directed the Commission to review EDU's earnings from an ESP in light of a threshold of its creation that would be considered significantly excessive. Mr. Effron provided little rationale to justify departing from the SEET. The thinness of a rationale speaks volumes: it loudly suggests that, being free of the SEET, Mr. Effron could do whatever he wanted in an effort to create a desired number to argue that the Companies' earnings were excessive.

Having abandoned the SEET for little reason, Mr. Effron's calculation bears no resemblance to any accepted calculation of earnings. Mr. Effron admitted that his calculations did not use any methodology that would be used in a distribution base rate case. For example,

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[1057] Hearing Tr. Vol. XXI, p. 4136.

[1058] For example, he understood that if the Companies' rates under the ESP resulted in the utilities receiving excess returns, such earnings would be refunded to customers. Hearing Tr. Vol. XXI, pp. 4136-37 (Effron Cross).

[1059] See Case No. 10-1265-EL-UNC; 11-4553-EL-UNC; 12-1544-EL-UNC; 13-1147-EL-UNC; and 14-0828-EL-UNC.

[1060] Hearing Tr. Vol. XXI, pp. 4136, 4137 (Effron Cross). Please note that the Companies have not been found to have exceeded their Significantly Excessive Earnings Threshold. *See* the Commission *Opinion and Order* in the following cases: 10-1265-EL-UNC; 11-4553-EL-UNC; 12-1544-EL-UNC; 13-1147-EL-UNC; and 14-0828-EL-UNC.

his calculation included revenues and expenses that would not be included in a base rate case.[1061] He included revenues and expenses from riders that would not be included in a base rate case.[1062] He also included sale and leaseback revenues that may or may not be included in a base rate case.[1063] He did not make certain adjustments to expenses that would usually be made in a rate case, *e.g.*, normalizing depreciation or property taxes.[1064] He also didn't make any adjustments to rate base for regulatory assets, except one adjustment for RCP deferrals, or any adjustments for allowances on working capital.[1065]

His calculations also include other errors, regardless of which method he used. For example, his calculation does not reflect that the Companies' revenue requirements under Rider DCR has exceeded its caps.[1066] And he used the wrong cost of debt.[1067] Simply put, the Commission cannot rely on, or give any weight to, Mr. Effron's calculations.[1068]

Further, the comparison rate of return used by Mr. Effron makes no sense. Mr. Effron compared his calculated return to a return calculated by OCC witness Woolridge.[1069] But Dr. Woolridge's rate-of-return recommendations were returns for FES. Mr. Effron was unaware how Dr. Woolridge had derived FES's cost of long-term debt and used FES's long-term debt and

[1061] Hearing Tr. Vol. XXI, p. 4137 (Effron Cross).

[1062] *Id.*

[1063] Hearing Tr. Vol. XXI, p. 4138 (Effron Cross).

[1064] Hearing Tr. Vol. XXI, pp. 4138-39 (Effron Cross).

[1065] Hearing Tr. Vol. XXI, pp. 4140-41 (Effron Cross).

[1066] Hearing Tr. Vol. XXI, p. 4139-40 (Effron Cross).

[1067] *Id*. Mr. Effron used the Companies' cost of debt as reported in their last distribution base rate case. He admitted that the Companies' cost of debt was likely different now.

[1068] NOPEC similarly relies upon Mr. Effron to make similar arguments opposing Rider DCR. NOPEC Brief, p. 62. For the same reasons discussed above, NOPEC's argument should be rejected as well.

[1069] Effron Direct, pp. 17-18.

capital structure in his analysis.[1070] Mr. Effron volunteered, "I took what the numbers were, and I didn't try to get behind them."[1071]

OCC/NOAC's arguments that Riders DCR and GDR violate important regulatory principles, based mostly on OCC/NOPEC witness Kahal's testimony, are without merit. As an initial matter, underlying many of Mr. Kahal's arguments that various aspects of ESP IV violate important regulatory principles are his doubts about the efficacy of the Commission's prudence review process.[1072] Indeed, Mr. Kahal believes that "there is less risk associated with recovery of costs through a cost tracker than a base rate case" because, in part, prudence disallowances are "rare."[1073] Mr. Kahal admitted, however, that he has never participated in an Ohio cost recovery rider audit proceeding, has never reviewed an Ohio cost recovery rider audit proceeding, including the proceedings related to Rider DCR, and has not been involved in a base rate case in Ohio for many, many years.[1074] Mr. Kahal's lack of experience was made clear by Staff witness McCarter, who testified that Rider DCR costs were subject to Commission review and approval, that Staff audited Rider DCR, and that Staff conducted field visits to verify the DCR investments.[1075] Mr. Kahal also admitted that he was aware that in recent years the Commission has disallowed significant portions of costs related to storm damage recovery and alternative

[1070] Hearing Tr. Vol. XXI, pp. 4142-43 (Effron Cross).

[1071] Hearing Tr. Vol. XXI, p. 4143 (Effron Cross). Given Mr. Effron's demonstrated lack of diligence, it should be no surprise that portions of his testimony in this proceeding were simply copied from testimony he provided in AEP Ohio's most recent ESP proceeding. Hearing Tr. Vol. XXI, pp. 4101-04 (Effron Cross).

[1072] *See* Kahal Second Supp., p. 34 (arguing that there will be no "detailed base rate case type investigation of the [Companies'] earnings and distribution cost of service for at least 16 years" and that it is "very unclear whether the PUCO would have any authority to disallow rate recovery through Rider RRS . . . that the PUCO finds to be improper or imprudent.")

[1073] Hearing Tr. Vol. XXIV, pp. 4901, 4923 (Kahal Cross).

[1074] Hearing Tr. Vol. XXIV, pp. 4900-01 (Kahal Cross).

[1075] Hearing Tr. Vol. XXIX, pp. 5882-84. (McCarter Cross) energy portfolio standard costs.[1076] Mr. Kahal's testimony and his qualifications as an expert on this subject are therefore in serious doubt, and his testimony should be afforded little weight by the Commission.

Moreover, Mr. Kahal relies on OCC witness Effron for the observation that Riders DCR and GDR are "cost trackers" that, as a general matter, "distort or blunt cost control incentives and 'are contrary to sound ratemaking practice.'"[1077] Mr. Effron's testimony on this point was, however, eviscerated at hearing.

Mr. Effron admitted that for purposes of reaching his opinions, he did not review the ESP statute, or the laws in other states regarding whether they might authorize a rider that recovers capital additions.[1078] He did not know if the ESP statute authorizes single-issue ratemaking or incentive ratemaking.[1079] (Of course, it does. [1080]) Mr. Effron admitted that several states in which he has testified – including Ohio, Rhode Island, Massachusetts, Illinois and Pennsylvania – do have riders that allow for the recovery of capital costs.[1081]

Mr. Effron further acknowledged that cost tracker riders provide a host of benefits, which include providing incentives for utilities to replace, rather than maintain, equipment and reducing regulatory lag.[1082] He also recognized that utility commissions have found that cost-tracker riders like Rider DCR are a way of removing the disincentive to invest in infrastructure.[1083] Additionally, he agreed that cost trackers can offer utilities the advantage of shortening the lag

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[1076] Hearing Tr. Vol. XXIV, pp. 4924-25 (Kahal Cross).

[1077] Kahal Supp., p. 21.

[1078] Hearing Tr. Vol. XXI, pp. 4105-06 (Effron Cross).

[1079] Hearing Tr. Vol. XXI, p. 4130 (Effron Cross).

[1080] Section 4928.143(B)(2)(h).

[1081] Hearing Tr. Vol. XXI, pp. 4106, 4130 (Effron Cross).

[1082] Hearing Tr. Vol. XXI, pp. 4125, 4128-29 (Effron Cross).

[1083] Hearing Tr. Vol. XXI, p. 4125 (Effron Cross).

between occurrence and recovery of costs, which can lower the utility's risk and, correspondingly, lower its cost to finance capital projects.[1084]

Mr. Effron also admitted that the Companies have other cost tracker riders, but he could not identify any other specific rider.[1085] In short, Mr. Effron's hearing testimony made it abundantly clear that his argument that cost tracker riders are generally "contrary to sound ratemaking principles" was nothing but a hollow assertion that is wholly unsupported by Ohio law or Commission precedent. Accordingly, Mr. Kahal's regurgitation of Mr. Effron's unfounded analysis should be disregarded by the Commission.

There is little dispute that the Companies' distribution capital requirements merit the requested increases in the cost recovery caps. No witnesses could contest that actual revenue requirements have increased $30 million annually on average.[1086] Thus, based on historical performance the Companies likely will have revenue requirements associated with millions of dollars of investments during ESP IV that they will not recover through Rider DCR.

Contrary to Mr. Kahal's claims, Rider DCR does not violate important regulatory principles. Rider DCR, previously approved by the Commission in the Companies' ESP II and ESP III, will continue to provide for important and timely investments in the Companies' infrastructure and will remain subject to an extensive annual audit process.[1087] Thus, the Companies' customers will retain the benefit of a reliable distribution infrastructure. Moreover, as provided in the Third Supplemental Stipulation, the Companies must show that what they seek to recover was actually spent, they must reconcile estimated plant in service balances to actual

[1084] Hearing Tr. Vol. XXI, pp. 4128-30 (Effron Cross). *See also* Hearing Tr. Vol. XX, p. 3927 (Company witness Fanelli discussing mitigation of regulatory lag).

[1085] Hearing Tr. Vol. XXI, pp 4116-17 (Effron Cross).

[1086] *See*, *e.g.* Hearing Tr. Vol. XXI, pp. 4117-19 (Effron); Hearing Tr. Vol. XXXVIII, p. 8231 (Kahal – "I am not challenging Mr. Fanelli's number.")

[1087] Mikkelsen Direct, p. 13; Hearing Tr. Vol. XXIX, pp. 5883-84 (McCarter Cross) (describing the audit process).

plant in service balances, and they must participate in Staff's annual audit of Rider DCR which will confirm that the amounts for which recovery are sought are not unreasonable.[1088]

OCC/NOAC and OMAEG also oppose Rider DCR, challenging whether Rider DCR is necessary to contribute to the reliability of the Companies' system. None of these parties dispute that the Companies' distribution system is currently reliable and that the Companies have consistently met or exceeded Commission-approved reliability standards.[1089] These parties argue, however, that there is no justification to continue Rider DCR because the Companies have not shown that customer and utility expectations regarding reliability are aligned. This argument is based on the testimony of OCC witness Williams who claimed, "customers are unwilling to pay more to avoid non-major outages" and therefore customer and utility expectations on this issue "are not aligned."[51] This claim is based on the misuse of a 2013 customer perception survey undertaken on behalf of the Companies. **[BEGIN CONFIDENTIAL]** [redacted]

[1088] Third Supp. Stip., Section V.G.2.

[1089] OMAEG Brief, p. 13.

[1090] Williams Direct, p. 20.

[1091] Williams Direct, Ex. JDW-5, p. 15 (emphasis added).

[1092] Hearing Tr. Vol. XXVIII, p. 5794 (Williams Cross).

[redacted] **[END CONFIDENTIAL]** Consequently, any argument based on his analysis should be afforded little weight by the Commission.

NOPEC asserts a similar argument stating, "Moreover, the Companies fail to demonstrate why increases to the revenue caps for Rider DCR are required to maintain reliability."[1094] NOPEC simply misses the point: the reliability in the Companies' service territories has improved and remains good *because of Rider DCR.* Company witness Mikkelsen showed how Rider DCR had led to solid reliability for customers since its inception.[1095] NOPEC's argument is akin to arguing that since there is no crime, we should get rid of all the police. Neither make sense.

The Companies and customers reliability expectations are aligned, as confirmed by Staff Witness Nicodemus. Mr. Nicodemus testified that the Companies' reliability expectations are consistent with those of their customers and they have met the requirements of Section 4928.143(B)(2)(h).[1096]

Wal-Mart suggests that the Commission should consider simplifying the Companies' rate structure to eliminate riders, including by requiring that the Companies file a new base

[1093] Hearing Tr. Vol. XXVIII, p. 5792 (Williams Cross).

[1094] NOPEC Brief, p. 62.

[1095] Mikkelsen Direct, pp. 9-10; Hearing Tr. Vol II, p. 252 (Mikkelsen Cross).

[1096] Nicodemus Direct, p. 10.

distribution rate case at the conclusion of this proceeding.[1097] However, Wal-Mart witness Chriss could not identify any riders that could be deleted.[1098] He also recognized that other utilities in Ohio have similar rate structures, and that Wal-Mart did not have difficulty calculating its rates as a GS customer.[1099] Further, he could not say whether a base rate distribution case would actually result in the elimination of any riders.[1100] Lastly, and perhaps most importantly, he did not address the cost to customers and all interested parties of eliminating the eight-year base distribution rate freeze.[1101] As a result, the Commission lacks reasonable grounds to require a base distribution rate case filing in an effort to simplify existing rate structures.

NOPEC also raised the specter of the Commission denying Rider DCR and ordering a base rate case to be filed.[1102] NOPEC's first rationale is that the Companies' return on equity is out of date, baldly asserting it would be lower now.[1103] NOPEC is wrong.[1104] Based upon the evidence presented during the proceeding, the Companies' cost of debt has actually increased.[1105] Further, the only evidence of the level of current rates of return were 11.15% for AEP in a recent

[1097] Wal-Mart Brief, p. 3; Chriss Direct, pp. 4-6.

[1098] Hearing Tr. Vol. XXI, p. 4058 (Chriss Cross).

[1099] Hearing Tr. Vol. XXI, pp. 4058-59 (Chriss Cross).

[1100] Hearing Tr. Vol. XXI, p. 4059 (Chriss Cross).

[1101] *See* Third Supp. Stip., Section V.G.1.

[1102] NOPEC Brief, p. 61.

[1103] *Id*.

[1104] NOPEC refers to the testimony of OCC witness Woolridge for the proposition that stocks are at all-time highs. For the Companies, this is also wrong. NOPEC Brief, p. 61.

[1105] *See* Hearing Tr. Vol. XVIII, p. 3661 (Savage Cross); Hearing Tr. Vol. XX, p. 3979 (Fanelli Cross). *See also In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices, and Tariff Approvals*, Opinion and Order, Case No. 07-551-EL-AIR, p. 22.

case and 10.38% for ATSI, determined late last year.[1106] So approval of Rider DCR as part of Stipulated ESP IV is reasonable and should be approved.

Similarly, Rider GDR will permit the timely recovery of government-mandated costs over which the Companies would have no control.[1107] And before any costs can be recovered under Rider GDR, the Companies will have to apply first for approval for the type of cost and then the amount of that cost, as Mr. Kahal admitted at hearing.[1108] Therefore, the argument raised by some intervenors that Rider GDR is an open ended recovery vehicle and permits the Companies to charge customers for future costs related to programs required by government-mandated directives is wrong. As with Rider DCR and the Companies' other riders, Rider GDR will be subjected to rigorous review by the Commission and Staff.[1109]

C. Competitive Market Reforms Recommended By RESA And Exelon Lack Record Support And Are Unnecessary.

1. The Commission should approve the Companies' Electric Generation Supplier Coordination Tariffs ("Supplier Tariffs") as modified and reject RESA's criticisms.

RESA criticizes certain changes to the Companies' Supplier Tariffs. First, RESA objects to a proposed amendment to the definition of "Bill Ready" in the Companies' Supplier Tariffs to clarify that bill-ready billing involves the CRES provider calculating its customers' generation charges to be billed.[1110] As an initial matter, RESA improperly attempts to utilize testimony filed by Teresa Ringenbach on behalf of Direct Energy Business, LLC and RESA in Duke Energy Ohio's ("Duke") ESP Case, Case No. 14-841-EL-SSO, and Direct Energy's Brief from

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[1106] *See* Staub Direct, pp. 3-5; Hearing Tr. Vol. XXXVI, p. 7631-32 (Mikkelsen Cross); Third Supp. Stip., Section V.D.3.

[1107] McMillen Direct, p. 4.

[1108] Hearing Tr. Vol. XXIV, p. 4905 (Kahal Cross).

[1109] Hearing Tr. Vol. II, p. 255 (Mikkelsen Cross); Hearing Tr. Vol. XXIV, p. 4905 (Kahal Cross).

[1110] RESA Brief, p. 11-12; Bennett Direct, p. 8. *See* Company Ex. 1, Attachment 5, Electric Generation Supplier Coordination Tariff, 1st revised page 3 of 52.

the *AEP ESP3* case for the assertion that the Companies' amendment to their Supplier Tariffs is "similar to Duke Energy Ohio Inc.'s attempt to unreasonably narrow what it would bill and collect as part of consolidated billing."[1111] RESA's improper citation to evidence in Duke's ESP case is puzzling considering the Commission in that case rejected RESA's argument and approved Duke's proposed amendment to its bill-ready billing definition:

> The Commission further finds that, at this time, the Company's assertion that bill ready billing should be limited to only electric commodity charges is reasonable. The Commission notes that the tariff defines what "commodity" means and later provides examples of what is considered "noncommodity." Because all customers must bear the cost of unpaid bills, and because the evidence in these cases reflects that Duke does not have the technology to separate commodity and noncommodity charges, the Commission does not find it reasonable to allow various noncommodities to be added to the bills.[1112]

The Commission should likewise here approve the Companies' amendment to the bill ready definition in the Supplier Tariffs because, as discussed below, it simply clarifies the types of charges that can be included in bill ready billing for purposes of consolidated billing with CRES providers.

RESA is concerned this change unduly discriminates against CRES providers and might prevent CRES providers from charging their customers for non-commodity goods and services using the Companies' consolidated billing.[1113] RESA is mistaken, given that non-commodity goods and services already fall outside the scope of the Companies' Supplier Tariffs. The Companies' Supplier Tariffs apply only to Competitive Retail Electric Service, which includes "retail electric generation, aggregation, power marketing, and power brokerage services supplied to Customers of the Company,": the Supplier Tariff does not apply to non-commodity goods and

[1111] RESA Brief, p. 11-12.

[1112] Case No. 14-841-EL-SSO, *Opinion and Order*, p. 89 (April 2, 2015).

[1113] RESA Brief, p. 12..

services.[1114] Indeed, RESA witness Bennett admitted that third parties providing non-commodity products and services are not subject to the Companies' Supplier Tariff.[1115] He also agreed that CRES providers are free to offer these products and services and to charge for them on their own.[1116] He also was unaware of any utility anywhere that currently allows CRES providers to charge for non-commodity products and services using utility consolidated billing. Notably, he lacked any proof that utility billing systems have the level of customization or flexibility required to permit consolidated billing of CRES provider non-commodity products and services.[1117] And, although RESA witness Bennett incorrectly contended that the Companies permit "other service providers who are not CRES providers" to bill for non-generation items on the consolidated bills, he admitted that he does not know the nature of the Companies' relationship with any providers of the Companies' non-commodity goods and services.[1118] Thus, the Commission lacks any evidentiary basis to reject the Companies' proposed modification to the supply tariff's definition of "Bill Ready." Moreover, RESA has not presented any evidence that the Companies' billing system is even capable of billing non-commodity charges for CRES providers as part of the Supplier Tariffs, especially in light of the fact that the Supplier Tariffs do not apply to charges that are not part of competitive retail electric service.

[1114] Company Ex. 1, Attachment 5, Electric Generation Supplier Coordination Tariff, 1st revised page 3 of 52 (defining Competitive Retail Electric Service to mean "retail electric generation, aggregation, power marketing, and power brokerage services supplied to Customers of the Company."); *id.*, 1st revised page 7 of 52, Part I.C. ("This Tariff's provisions apply to all Certified Suppliers providing Competitive Retail Electric Services to Customers located in the Company's service territory"; *id.*, 1st revised page 8 of 52, Part II.A. ("This Tariff sets forth the basic requirements for interactions and coordination between the Company and Certified Suppliers necessary for ensuring the delivery of Competitive Retail Electric Service from Certified Suppliers to their Customers.").

[1115] Hearing Tr. Vol. XXVI, pp. 5339-41 (Bennett Cross).

[1116] *Id.* at 5340.

[1117] *Id.* at 5341.

[1118] *Id.*

Next, RESA contends that by amending their Supplier Tariffs to remove the reference to hard copy or electronic file formats of non-summary interval metering information, the Companies intended to halt their current practice of providing non-summary interval metering information.[1119] The Companies did not make such a proposal and are not proposing to halt their current practice of providing non-summary interval metering information. Indeed, as Company witness Smialek testified, the Companies are proposing to expand the availability of interval metering data through their proposed supplier portal, which, for customers who have interval meters, would include 12 months of hourly interval metering data.[1120] As the Companies indicated to the Commission in their November 21, 2014 letter in Case No. 12-3151-EL-COI, the Companies' current Supplier Tariffs already provide for the terms and conditions and charges associated with providing this information and the Companies are in compliance with the Commission's May 21, 2014 Entry on Rehearing in that case.[1121] With the Companies' acknowledgment that they are not making the change to the Supplier Tariffs that RESA feared, the Commission should reject RESA's unsubstantiated recommendation that the Commission require the Companies to provide interval metering data free of charge especially in light of the fact that the current Supplier Tariffs contain a charge and the Companies have not proposed a change to that charge.

RESA also argues that the Companies' amendment to the unaccounted for energy ("UFE") provision of their Supplier Tariffs is improper because it allocates UFE solely to CRES

[1119] RESA Brief, p. 13.

[1120] Hearing Tr. Vol. V, p. 1043 (Smialek Cross).

[1121] Notably, the Commission's Retail Market Investigation Finding and Order and Entry on Rehearing that the Commission, in ordering that the electric distribution utilities to provide interval data to CRES providers, adopted Staff's recommendation, which only recommended that EDUs "that have deployed AMI" to provide such data. Case No. 12-3151-EL-COI, Finding and Order, pp. 35-36 (March 26, 2014). The Companies have not deployed AMI and, therefore, this provision of the Order does not apply to them.

providers.[1122] Put simply, RESA is wrong. Nothing in the amended Supplier Tariffs allocates UFE solely to CRES providers. The amended Supplier Tariffs clearly state that "Certified Suppliers will be responsible for Unaccounted for Energy **on a load ratio share basis….**"[1123] The Companies amended the UFE provision simply to provide that the load ratio share basis will be calculated by the Company pursuant to the Supplier Energy Obligation Manual available on the Company's website.[1124] RESA witness Bennett admitted that the Supplier Energy Obligation Manual requires UFE to be allocated proportionally between the Companies and a CRES provider on load ratio basis.[1125] The tariff does not, in any way, remove "any responsibility FirstEnergy may have and [place] the risk solely on CRES providers, as RESA asserts.[1126] RESA witness Bennett agreed:

> Q. You would agree that with the reference to the manual, as it stands today, the change is not removing any responsibility from the distribution utility and placing unaccounted for energy risk solely on CRES providers, correct?
>
> A. Correct.[1127]

RESA's arguments are without merit, and the Companies' Supplier Tariffs amendments should be approved.

2. The Companies' bill format change should be approved.

Although not entirely clear from its Brief, RESA appears to complain that the Companies' actual electronic filing of their proposed bill format is inadequate because the pdf version of the proposed bill format is not in the same color or size as the Companies' actual bill

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[1122] RESA Brief, pp. 14-15.

[1123] Company Ex. 1, Attachment 5, Electric Generation Supplier Coordination Tariff, 1st revised page 30 of 52.

[1124] *Id.*

[1125] Hearing Tr. Vol. XXVI, p. 5345 (Bennett Cross).

[1126] RESA Brief, p. 15.

[1127] Hearing Tr. Vol. XXVI, p. 5346 (Bennett Cross).

format.[1128] On August 4, 2014, the Companies filed along with Company witness Smialek's testimony, a proposed bill format. When questioned by RESA's counsel at hearing, Ms. Smialek testified *three times* that the Companies print their bills in black and white not color.[1129] Therefore, the Companies' logo and a CRES provider's logo will both be in black and white, in compliance with the Commission's March 26, 2014 Finding and Order in Case No. 12-3151-EL-COI.[1130] Ms. Smialek further testified that due to a technical difficulty, the electronically filed version of the bill format filed with her testimony, may have appeared to not be white, which was a technical error in the filing that Ms. Smialek explained during cross examination.[1131] Ms. Smialek still further testified that the CRES provider's logo will appear as the same size as the Companies' logo.[1132] As evidenced by Ms. Smialek's testimony, the Companies' bill format is in compliance with the Commission's March 26, 2014 Finding and Order in Case No. 12-3151-EL-COI and it should be approved. Any complaints from RESA on this issue should be ignored.

3. A stakeholder collaborative meeting to assist with the development and implementation of the supplier web portal is not necessary.

RESA also recommends that the Companies should be ordered to conduct a collaborative process to review details of the planned web portal discussed in Company witness Smialek's testimony.[1133] As with its other recommendations, RESA fails to provide evidentiary support justifying an additional collaborative process here. Indeed, RESA witness Bennett reviewed Ms. Smialek's list of information to be made available on the supplier web portal and could not

[1128] RESA Brief, pp. 15-16.

[1129] Hearing Tr. Vol V, pp. 1052, 1053, 1055 (Smialek Cross).

[1130] Case No. 12-3151-EL-COI, Finding and Order, p. 29.

[1131] Hearing Tr. Vol. V, p. 1055 (Smialek Cross).

[1132] *Id.*at 1057.

[1133] RESA Brief, pp. 17-18; *See* Smialek Direct, pp. 4-7.

identify any information that was missing.[1134] He also agreed that RESA is not proposing any changes to the portal described in Ms. Smialek's testimony.[1135] This lack of evidence on RESA's part should not be surprising given that the Companies have designed the supplier web portal based on input from RESA and others through the Retail Market Investigation ("RMI") process and other meetings.[1136] Although the Companies remain open to discussion of other information to include in the web portal, if any is identified in the future, Ms. Smialek did not testify that "FirstEnergy would be willing to have stakeholder/collaborative meetings to discuss the portal before it becomes fully operational" as RESA asserts.[1137] Ms. Smialek specifically stated: "we would not be opposed to having additional meetings *if it were necessary to*...get the right elements."[1138] Given the lack of demonstrated need for an additional collaborative process, there is no basis for the Commission to require one.

4. The Companies have not proposed a purchase-of-receivables program and RESA has failed to demonstrate that such a program is warranted or necessary.

Also lacking evidentiary support is RESA's request that the Commission graft a new, undefined purchase-of-receivables ("POR") program onto the Companies' Stipulated ESP IV.[1139] RESA witness Bennett admitted that: (1) he lacked a specific POR program to propose; (2) he had not determined what discount rate would be appropriate; and (3) he had no proof that a POR program would benefit shopping in the Companies' territories.[1140] Moreover, the Commission has previously rejected a POR program proposed by RESA in the Companies' ESP III case, Case

[1134] Hearing Tr. Vol. XXVI, p. 5353 (Bennett Cross).

[1135] Hearing Tr. Vol. XXVI, pp. 5353-54 (Bennett Cross).

[1136] Smialek Direct, pp. 3-4; Hearing Tr. Vol. V, p. 1039 (Smialek Cross).

[1137] Hearing Tr. Vol. V, p. 1047 (Smialek Cross).

[1138] Hearing Tr. Vol. V, p. 1051 (Smialek Cross)(emphasis added).

[1139] RESA Brief, p. 21-24; *See* Hearing Tr. Vol. XXVI, p. 5347 (Bennett Cross).

[1140] Hearing Tr. Vol. XXVI, pp. 5347-50 (Bennett Cross).

No. 12-1230-EL-SSO. In that case, the Commission noted the lack of any evidence showing the absence of a POR program had inhibited competition:

> The Commission notes that we have previously addressed the question of the purchase of receivables in the FirstEnergy service territories. *WPS Energy Services, Inc., and Green Mountain Energy Company v. FirstEnergy Corp., et al.*, Case No. 02-1944-EL-CSS (*WPS Energy*). In *WPS Energy*, two marketers filed a complaint against the Companies for failing to offer a purchase of receivables program. On August 6, 2003, the Commission adopted a stipulation resolving the case (IGS Ex. la at 13). In the stipulation, the Commission approved the modification of the partial payment posting priority set forth in Commission rules, the marketers agreed to dismiss their complaints, and the Commission approved a waiver of any obligation of the Companies to purchase accounts receivable. *WPS Energy*, Case No. 02-1944-EL-CSS, Opinion and Order (August 6, 2003) at 3, 5, 8. Although the marketers have demonstrated that the purchase of receivables by the utility is their preferred business model, there is no record in this proceeding demonstrating that the absence of the purchase of receivables has inhibited competition. There is no record in this proceeding that the Companies are under any legal obligation to purchase receivables. There is no record that circumstances have changed since the adoption of the stipulation to justify abrogating the stipulation.[1141]

Here, RESA likewise has failed to demonstrate that the absence of a POR program has inhibited competition or that circumstances have changed since the *WPS Energy* case. RESA's general assertions that a POR program is its preferred business model and removes uncollectible risk for the CRES provider[1142] is not evidence that a lack of POR program has inhibited competition in the Companies' service territories. Indeed, RESA witness Bennett specifically admitted that he has no empirical evidence that the absence of POR is inhibiting competition in the Companies' service territories.[1143]

[1141] Case No. 12-1230-EL-SSO, *Opinion and Order*, p. 41 (July 18, 2012).

[1142] RESA Brief, p. 22.

[1143] Hearing Tr. XXVI, p. 5350 (Bennett Cross). During the hearing, Mr. Bennett responded that he did not have any empirical evidence, but as the transcript demonstrates, during deposition, Mr. Bennett admitted that he did not have any facts at all to demonstrate that the absence of a POR program is inhibiting competition.

In an effort to support its assertion that a POR program is necessary, RESA asserts that the partial payment priority adopted by the Commission in its rules is flawed.[1144] RESA asserts "To avoid a shut-off for an overdue account, a customer can have the payment priority shifted so that the EDU charges are paid first [to] avoid shut off." However, RESA has cited to no evidence or any authority that any EDU shifts the partial payment priority under these circumstances or that an EDU has any authority to shift partial payment priority under these circumstances. After all, the partial payment priority is mandated by Rule 4901:1-10-22(G) and no exceptions are indicated.

RESA also complains that a CRES provider is at a disadvantage in collecting past due amounts.[1145] However, RESA witness Bennett admitted that although a CRES provider cannot disconnect a customer, a CRES provider can drop a customer for nonpayment.[1146] He also admitted that a CRES provider can choose to not provide CRES to a customer who is a credit risk and that a CRES can account for risk of nonpayment in its pricing.[1147]

RESA claims that the CRES provider is not informed regarding customers' partial payments.[1148] Yet, RESA admits that the Commission remedied this issue in the Retail Market Investigation[1149] and that the Companies are currently providing information regarding a customer's payment to CRES providers.[1150] None of these "reasons" cited by RESA support a POR program in the Companies' service territories.

[1144] RESA Brief, pp. 21-22

[1145] RESA Brief, p. 21.

[1146] Hearing Tr. XXVI, p. 5351 (Bennett Cross).

[1147] Hearing Tr. XXVI, pp. 5351-5352 (Bennett Cross).

[1148] RESA Brief, p. 22.

[1149] RESA Brief, p. 22

[1150] Hearing Tr. XXVI, p. 5352 (Bennett Cross).

Next, RESA attempts to rely on a chart presented by Mr. Bennett in his Direct Testimony for the assertion that there are more supplier offers in areas with a POR program than in areas without a POR program.[1151] However, a review of the chart in Mr. Bennett's testimony merely shows that as of December 13, 2014, there were more offers on the Apples-to-Apples website for customers in Duke's service territory than in the Companies' territory. The chart does not show, and Mr. Bennett does not demonstrate, that there was an "increased number of suppliers" in Duke as a result of POR. In fact, RESA witness Bennett admitted that: 1) he does not know if the percentage of shopping customers in Duke has increased as a result of POR[1152]; 2) RESA has not done any studies to show that POR increases shopping[1153]; 3) he does not know of any CRES providers have said that they would not enter a territory until a POR program is implemented[1154]; and 4) the number of offers he listed in his chart could be for a number of reasons, one of which may or may not be POR.[1155]

RESA also cites to the Staff Work Plan in the RMI and asserts that Staff agreed that POR increases participation in the competitive market and provides benefits.[1156] However, a review of Staff's report demonstrates that Staff did not make this conclusion. Rather, Staff merely indicated, as Mr. Bennett identified in his Direct Testimony, that Duke (who has POR) has a "higher number of active CRES providers" and recognizes, as Mr. Bennett did, "that there are other factors that might lead to this increase."[1157] Moreover, although Staff found that a POR program may provide benefits and recommended that each EDU file an application for such, the

[1151] RESA Brief, p. 23

[1152] Hearing Tr. XXVI, p. 5348 (Bennett Cross).

[1153] Hearing Tr. XXVI, p. 5347 (Bennett Cross).

[1154] Hearing Tr. XXVI, p. 5349 (Bennett Cross).

[1155] Hearing Tr. XXVI, p. 5350 (Bennett Cross).

[1156] RESA Brief, p. 23.

[1157] Case No. 12-3151-EL-COI, Staff Work Plan at 16 (January 16, 2014).

Commission specifically rejected Staff's recommendation.[1158] RESA fails to cite the exact language of the Commission Finding and Order which encouraged EDUs to include a "POR program or *its equivalent*" – not just POR.[1159] As noted above, the Companies have an equivalent of a POR program arising out of a stipulation in the *WPS Energy* case. The fact that the Commission noted its encouragement that EDUs include a POR program or its equivalent[1160] in their next distribution rate case or SSO case, does not make it a legal obligation as Mr. Bennett freely admitted.[1161]

Moreover, RESA's citation to the Commission's Opinion and Order in the AEP-Ohio ESP case for the assertion that the Commission has found that POR is beneficial is misplaced. The Commission found, based on the record presented *in AEP-Ohio's case*, that POR in *AEP-Ohio's* territory is beneficial - not in any other EDU's territory.[1162] What the Commission may have decided was appropriate for AEP Ohio, based on the specific record in that proceeding, is not relevant in this case – which has a different record. Indeed, the Commission specifically recognized the unique circumstances in AEP-Ohio's case and found such proposal "should be evaluated on its own merits, on a case-by-case basis."[1163] Regardless, RESA has not demonstrated in this proceeding that a POR program would be beneficial to the *Companies*' customers.

Similarly, RESA's assertion that, because the Companies' utility affiliates have a POR program in their respective states means that the Companies should have one in Ohio, is likewise

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[1158] Case No. 12-3151-EL-COI, Finding and Order at 21 (Mar. 26, 2014).

[1159] *Id.* (emphasis added).

[1160] Case No. 12-3151-EL-COI, Finding and Order, p. 21 (Mar. 26, 2014).

[1161] Hearing Tr. XXVI, p. 5350 (Bennett Cross).

[1162] RESA Brief, pp. 22-23; *AEP ESP3 Order*, p. 81.

[1163] *AEP ESP3 Order*, p. 80.

misplaced.[1164] RESA has not demonstrated that the circumstances warranting POR in those states apply to Ohio. RESA further cites Company witness Moul's testimony that "based on the volatility [FES] saw in the marketplace after January of '14, [FES is] out of the residential marketplace."[1165] But this testimony does not demonstrate that competition has, in any way, stalled in the Companies' territories.

As in the ESP III proceeding, there is no basis in this record to compel the Companies to add a POR program to Stipulated ESP IV. For that reason, the Commission should deny RESA's request to add a POR program to the Companies' ESP.

5. The Commission Should Reject Exelon's Recommendation That The Companies Should Provide To PJM Daily Information That Reflects Actual Daily Aggregate PLC For The Zone Based On Customers.

Exelon expresses a concern that the aggregated Peak Load Contribution ("PLC") information provided on the Companies' website to CRES providers differs from the information provided to PJM.[1166] In particular, the Companies apply a scaling factor before they submit their PLC information to PJM, and Exelon would like the Companies not to apply the scaling factor before submitting the information to PJM.[1167] This process employed by the Companies is allowed by PJM rules.[1168] The process also is not unusual – other EDUs, including other FirstEnergy EDUs, follow the same approach.[1169] Indeed, Commonwealth Edison, an Exelon affiliate, applies a scaling factor to its PLC information before submitting it to PJM.[1170] Exelon

[1164] RESA Brief, p. 24.

[1165] RESA Brief, p. 23.

[1166] Exelon Brief, p. 78; Campbell Direct, p. 37-38.

[1167] Campbell Direct, p. 38; Hearing Tr. Vol. XXVI, p. 5258 (Campbell Cross).

[1168] Hearing Tr. Vol. XXVI, p. 5260 (Campbell Cross).

[1169] Hearing Tr. Vol. XXVI, pp. 5259-60 (Campbell Cross).

[1170] Hearing Tr. Vol. XXVI, pp. 5260-62; (Campbell Cross) and Company Ex. 108.

has not justified its proposal to change how the Companies submit information to PJM and therefore the Commission should reject it.

6. An "action agenda" to provide interval data to CRES providers is unnecessary.

RESA does not oppose the Companies time-of-day option of Rider GEN, but asks that the Commission require the Companies "to submit an action agenda to the Staff which will accomplish providing the necessary interval data electronically to CRES providers by the start of ESP IV in June 2016."[1171] There is no need for the Companies to submit an "action agenda" to Staff at this time, and it is unclear what such a submission would even include. As RESA witness Bennett admitted during cross examination, if an EDU does not have an AMI smart grid program it is not required by the Commission's Retail Market Investigation Finding and Order to provide a time-differentiated rate pilot program.[1172] It is therefore premature to require the Companies to submit any form of "action agenda" to the Commission. Further, the Companies already have committed to provide the type of information sought by RESA, as part of their commitment to file a grid modernization business plan.[1173]

RESA also contends that the continuation of the time-of-day option under Rider GEN should be limited to only those customers currently taking service under it.[1174] This recommendation is unfounded and is inconsistent with the current Commission approved tariff. Limiting participation in this manner would restrict the benefits to customers of having an

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[1171] RESA Brief, p. 20.

[1172] Hearing Tr. Vol. XXVI, p. 5355 (Bennett Cross).

[1173] Third Supplemental Stipulation, Section V.D.2.c., p. 10.

[1174] RESA Brief, p. 20.

opportunity to lower their electric bills and better understand the benefits of time-differentiated pricing.[1175] Therefore, RESA's recommendation should be denied.

RESA's requests related to interval data are premature and already addressed elsewhere in Stipulated ESP IV, so nothing more needs be done.

D. Rider NMB Should Be Approved As Proposed By Stipulated ESP IV.

Stipulated ESP IV proposes the continuation of Rider NMB with certain changes designed to include certain additional non-market based charges.[1176] As demonstrated previously, by reducing risk premiums (among other things) these changes will reduce overall costs to customers.[1177]

RESA and Exelon recommend that the Commission approve Rider NMB, but not include certain PJM Billing Line Items proposed by the Signatory Parties for inclusion.[1178] OMAEG recommends that the Commission not approve any of the proposed changes to Rider NMB.[1179] None of these positions has merit.

As explained by Company witness Stein, Rider NMB recovers costs associated with non-market based charges that are billed by PJM on a nonbypassable basis.[1180] The Companies used four factors to determine whether a PJM charge is non-market based and should be included in Rider NMB instead of being billed to the CRES provider or CBP supplier: (1) marketability, such as an intercontinental exchange or a Chicago mercantile exchange or a market in PJM to buy or sell that explicit product; (2) controllability, whether there is something at PJM to either

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[1175] Companies' Initial Brief, p. 34.

[1176] Stein Direct, pp. 13-15.

[1177] *See* Companies' Initial Brief, pp. 99-102

[1178] RESA Brief, p 2-3; Bennett Direct, p. 12; Exelon Brief, p.9; Campbell Direct, pp. 27-29.

[1179] OMAEG Brief, pp. 15-19.

[1180] Stein Direct, p. 12.

elect or select in their various systems; (3) predictability, whether there is a historical level of charge that has not varied much over an extended period of time that can be used to predict the future amount of that charge; and (4) transferability, the ability to transfer a charge from load serving entities to the Companies.[1181] He also demonstrated that each of the additional line items proposed for inclusion with Rider NMB met those criteria.[1182]

Exelon opposes including nine items within Rider NMB. But Exelon provides no basis upon which the Commission could reasonably reject the changes to Rider NMB.[1183] More specifically, the line items Exelon seeks to exclude from Rider NMB[1184] exhibit characteristics that would cause them to be included in Rider NMB based upon the four criteria for inclusion noted above. For example, the Planning Period Congestion Uplift charges that Exelon seeks to exclude meet all of the criteria for *inclusion* in Rider NMB, i.e., they are not marketable, controllable, predictable or transferable.[1185] In fact, Exelon witness Campbell specifically agreed that they are neither controllable nor predictable.[1186]

Balancing Operating Reserves charges and Balancing Operating Reserves for Load Response and Reactive Services charges are neither marketable, controllable nor predictable.[1187] Exelon witness Campbell was generally uninformed regarding Balancing Operating Reserve charges, but also agreed they are out-of-market and not predictable.[1188] RESA witness Bennett

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[1181] Hearing Tr. Vol. V, pp. 941-42 (Stein Cross).

[1182] *See* Hearing Tr. Vol. V, pp. 942-943; 946-947; 948-949 (Stein Cross).

[1183] Exelon Brief, p. 9.

[1184] Campbell Direct, pp. 27-29.

[1185] Hearing Tr. Vol. V, pp. 942-43 (Stein Cross).

[1186] Hearing Tr. Vol. XXVI, pp. 5255-56 (Campbell Cross). *See* Company Ex. 107, Customer Guide to PJM Billing.

[1187] Hearing Tr. Vol. V, pp. 946-47, 948-49 (Stein Cross).

[1188] Hearing Tr. Vol. XXVI, pp. 5247-55 (Campbell Cross).

agreed that the charges included in Balancing Operating Reserves can be volatile and that CRES providers cannot hedge against at least some of the charges in Balancing Operating Reserves.[1189]

PJM Line Item 1450, which the Companies proposed to include for recovery in Rider NMB, merely updates previously billed costs under PJM Line Item 1320, which is non-market based.[1190] Although Exelon witness Campbell was unaware what specific charges actually are included in PJM Line Item 1320, he could not dispute that they are non-market based and, thus, that PJM Line Item 1450 also is non-market based.[1191] Therefore, all of the PJM bill line items included in Rider NMB as part of Stipulated ESP IV should be approved, and RESA and Exelon's recommended modifications to Rider NMB should be rejected.

OMAEG's claim that RTO uplift charges are somehow related to providers purchase and hedging strategies was unsupported in the record, and is simply incorrect.[1192] Uplift charges include costs incurred by PJM as a result of out-of-merit dispatch.[1193] Such dispatch occurs when generation from a particular facility is needed for reliability purposes, including in emergency conditions.[1194] When such conditions will occur, which resources will be dispatched and how much the cost of such dispatch will be are not knowable[1195] and, therefore, related uplift charges are unpredictable.

[1189] Hearing Tr. Vol. XXVI, pp. 5346-5347 (Bennett Cross).

[1190] Stein Direct, p. 15; Campbell Direct, p. 27.

[1191] Stein Direct, p. 15; Campbell Direct, p. 26 (PJM Line Item 1320 is non-market based); Hearing Tr. Vol. XXVI, pp. 5245-46.

[1192] OMAEG Initial Brief, p. 16.

[1193] Hearing Tr. Vol. V, p. 982 (Stein Cross).

[1194] Hearing Tr. Vol. V, p. 986 (Stein Cross).

[1195] Hearing Tr. Vol. V, pp. 948-949 (Stein Cross).

OMAEG's concerns about double billing (once by a CRES provider and once by the Companies) have been raised in previous ESPs and rejected.[1196] In any event, Company witness Mikkelsen testified that the Companies, following past practice, would work with the CRES community to resolve any issues associated with the potential double recovery of the proposed additional Rider NMB charges. Ms. Mikkelsen observed that the Companies and the CRES community were able to successfully work through the transition between the Companies ESP I and ESP II where the current Rider NMB expenses became the responsibility of the Companies instead of suppliers.[1197] Further, any changes that would be made to Rider NMB would occur as part of the Companies' annual Rider NMB filing and would be subject to the review and approval of the Commission before going into effect.[1198] Therefore, OMAEG's recommendation to not allow any modification to Rider NMB should be rejected.

E. Rider ELR Benefits Customers And The Regional Economy.

OMAEG and OCC/NOAC claim that the ELR program provides no benefit to customers that do not participate in the program.[1199] This is incorrect. Rider ELR provides multiple benefits to all customers, including reliability through its interruptible provisions, economic development and job retention benefits in the Companies' service territories, and Rider ELR supports Section 4928.02 by promoting Ohio's effectiveness in the global economy.[1200] The Commission has also recognized in the Companies' ESP III proceeding that Rider ELR provides

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[1196] *See, e.g.*, Case No. 12-426-EL-SSO, Second Entry on Rehearing at 25 (March 19, 2014) ("The Commission is not persuaded that bifurcating the TCRR into the TCRR-N and TCRR-B poses a significant risk of double-billing customers. As the Commission indicated in the Order, the Commission believes that bifurcating the TCRR into market-based and nonmarket-based elements more accurately reflects how transmission costs are billed to customers."); *AEP ESP3* Order, p. 68 (same)

[1197] Hearing Tr. Vol. XXXIV, p. 7023 (Mikkelsen Rebuttal Cross).

[1198] Hearing Tr. Vol. V, pp. 1003-1004 (Stein Cross).

[1199] OMAEG Brief, p. 67; OCC/NOAC Brief, p. 98.

[1200] Mikkelsen Rebuttal, p. 18.

benefits to all customers.[1201] The Commission specifically stated regarding Rider ELR that "in light of the fact that all customer classes benefit from the rates related to ELR and OLR" it was reasonable that all customers contribute toward ELR credits.[1202]

Indeed, the availability of interruptible load during an emergency, such as an extreme weather event, helps prevent the need to resort to load-shedding for firm service customers including residential and small commercial customers. This capability provides a clear benefit to both firm and non-firm customers. For example, during the Polar Vortex, interrupting the Companies' ELR customers helped avoid potential load shedding on a circuit-by-circuit basis in 30 minute increments for 142,000 customers.[1203]

OCC/NOAC also argue that the Rider ELR credit is an above-market credit and customers are forced to subsidize the program. OCC/NOAC are incorrect. The ELR credit is not an above-market credit. The Rider ELR credit $5 per kW of curtail load is equivalent to $165/MW-day, which is very representative of the $159 MW/day average price of capacity auctions in 2014/2015 – 2018/2019.[1204] Additionally, any costs collected for Rider ELR credits are netted against PJM capacity revenues received by the Companies from PJM.[1205]

OHA complains that it shouldn't pay charges under the Companies' Rider EDR(e), which collects from small and medium sized nonresidential customers costs associated with economic development for Rider ELR customers.[1206] Notably, OHA signed the stipulation in all three of the Companies' previous ESP cases, which included the charges about which OHA now

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[1201] ESP III Order, p. 37.

[1202] *Id*.

[1203] Strah Direct, p. 9; OEG Brief, p. 24.

[1204] Hearing Tr. Vol. III, p. 497 (Mikkelsen Cross).

[1205] Hearing Tr. Vol. II, p. 276 (Mikkelsen Cross).

[1206] OHA Brief, p. 4.

complains.[1207] This tariff charge was first approved by the Commission in the Companies' ESP I,[1208] and has remained an approved charge since that time to the present in the Companies' ESP III proceeding. As has been recognized, the Rider EDR(b) credit provides economic development for large industrial customers.[1209] Benefits for this rider flow to smaller nonresidential customers through increased commerce, production, and jobs in the local area.[1210]

It is unclear from OHA's Brief whether it urges the rejection of Rider EDR(e) (and thereby eliminate one of the credits received by Rider ELR customers) or whether OHA is requesting the Commission to have a different set of customers pay the charges under Rider EDR(e). The confusion arises, at least in part, from the fact that OHA did not present a witness during the hearing to present evidence explaining OHA's view. The only evidence referred to by OHA in support of its position was the outdated testimony of Staff setting forth Staff's initial litigation position. The Staff is a Signatory Party to Stipulated ESP IV and supports Rider EDR(b) and (e) as included therein, contrary to OHA's assertions.[1211] The Commission should adopt Rider EDR(b) and (e) as part of its approval of Stipulated ESP IV.

F. The Companies' Rider NMB Opt-Out Pilot Program Should Be Approved As Filed.

The Commission should approve the proposed NMB Opt-Out Pilot Program as included as part of Stipulated ESP IV. RESA and Exelon oppose the Rider NMB Opt-Out Pilot Program, claiming that it is unduly limiting, discriminatory and unjust because it excludes participation by

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[1207] *See* Stipulation in Case No. 08-935-EL-SSO and 12-1230-EL-SSO, and the Second Supplemental Stipulation in Case No. 10-388-EL-SSO.

[1208] Companies' ESP I Opinion and Order, Case No. 08-935-EL-SSO.

[1209] Hearing Tr. Vol. II, p. 274 (Mikkelsen Cross).

[1210] While OHA refers in its initial brief to rates DS and DP, the Companies believe they intended to refer to rates GS and GP, as those are the rate schedules that are responsible for the charges in Rider EDR(e).

[1211] *See* Third Supplement Stipulation, p. 22.

other interested stakeholders or customers.[1212] In addition, RESA claims that the Pilot is poorly designed.[1213] RESA's and Exelon's claims are without merit.

Any pilot program, by its nature, should be limited. The purpose of such programs is to conduct a test of the programs' potential costs and benefits. Here, through the Rider NMB Opt-Out Pilot Program, the Companies seek to study administrative burden and costs of having giving customers the option to have their CRES providers pay Rider NMB charges.[1214] Similarly, the Companies seek to determine whether such an option provides benefits to both participating and nonparticipating customers.[1215] The Companies should be allowed to undertake this test.

RESA asserts that a pilot program should contain four elements, and that, as proposed, the Rider NMB Opt-Out Pilot Program in Stipulated ESP IV does not include these components.[1216] RESA, however, provides no support or precedent for its suggested components. RESA provides no other circumstance where such components have ever been relied upon by the Commission or any other regulatory agency. Further, RESA witness Bennett admitted that a CRES provider is not required to provide an NMB product to pilot participants.[1217] In addition, Mr. Bennett agreed that the way PJM allocates these non-market based costs under the pilot would not change.[1218]

[1212] RESA Brief p. 49; Exelon Brief (p. 70)

[1213] RESA Brief p. 49;

[1214] Supp. Stip., pp. 3-5; Mikkelsen Third Supp., p. 2; Hearing Tr. Vol. II at 470 (Mikkelsen Cross).

[1215] Supp. Stip., pp. 3-5; Hearing Tr. Vol. II at 670-71 (Mikkelsen Cross).

[1216] RESA Brief, p. 50.

[1217] Hearing Tr. Vol. XXVI, p. 5357 (Bennett Cross).

[1218] *Id*. at 5358.

RESA further asserts that the program provides insufficient "information for the Commission to determine if the pilot was justified on a cost-causation basis."[1219] However, RESA fails to recognize both how NMB costs are currently allocated, and how NMB costs would be allocated under the pilot. Witness Mikkelsen testified that over 99% of charges in Rider NMB are allocated by NSPL. She stated, "To the extent that a customer participates in the pilot, they leave the companies' NMB service, and they are going to – their service provider, CRES provider, will be assigned those costs on the basis of their NSPL, and the costs assigned to the company will go down accordingly."[1220] OCC witness Rubin admitted on cross that NSPLs can be determined for a specific customer, and that the Rider NMB costs for customers participating in the pilot will not be assessed to the Companies, rather they will be assessed to the CRES provider and not be paid for by any other customer.[1221] Because of the lack of risk or harm to other customers, and the potential for a pilot group of customers to benefit from the pilot program, the Commission should approve the Rider NMB Pilot Program as part of Stipulated ESP IV.

G. No Additional Amendments Are Required To The Master SSO Supply Agreement ("MSA").

The Companies' MSA has functioned well for several years to procure sufficient and reasonably priced SSO load. Exelon seeks to have the Commission order several modifications to the Companies' Master SSO Supply Agreement ("MSA"). These proposed modifications include: (1) deleting the "notional quantity language" from the definition of "settlement amount"; (2) modifying the definition of "FE Ohio Aggregate" to include specific price node

[1219] RESA Brief, p. 50.

[1220] Hearing Tr. Vol. III, pp. 633, 642 (Mikkelsen Cross)

[1221] Hearing Tr. Vol. XXIII, pp. 4807-4810 (Rubin Cross) identifiers ("PNode IDs"); and (3) adding a change-in-law provision to the PIPP provision.[1222] None of the proposed changes are needed or appropriate, and should be rejected by the Commission.

As an initial matter, Mr. Campbell admitted at hearing that he had not communicated with any other SSO suppliers regarding whether they agreed to Exelon's suggestions for changing the Companies' policies, procedures, or contracts.[1223] Therefore, there is no evidence that other SSO suppliers see any wisdom, much less benefit, in adopting Exelon's suggested changes. As demonstrated below, each of his suggested modifications flies in the face of the record evidence.

Deleting the notional quantity language: According to Mr. Campbell, the notional quantity language transforms the MSA into a derivative instrument.[1224] In turn, such an alleged transformation supposedly renders it difficult for wholesale suppliers (presumably such as Exelon) "to appropriately manage their obligations" such that these suppliers will likely limit their participation in the Companies' CBP auctions for SSO load.[1225] This is not accurate. For starters, as the record demonstrates, the so-called notional quantity language contained in the Companies' current MSA has not prevented Exelon's participation in each of the Companies' SSO auctions over the term of ESP III. Indeed, Exelon has often been the winning bidder awarded the most tranches or been tied for the same:

- January 27, 2015 Auction: Exelon won 5 of 16 total tranches, the most of any winning bidder.[1226]

[1222] Exelon Brief, pp. 75-78.

[1223] Hearing Tr. Vol. XXVI, p. 5257 (Campbell Cross).

[1224] Campbell Direct, p. 34.

[1225] Campbell Direct, p. 35.

[1226] Company Ex. 109A; Hearing Tr. Vol. XXVI, p. 5274 (Campbell Cross).

- October 14 2014 Auction: Exelon won 5 of 16 total tranches, tied for most of any winning bidder.[1227]

- January 28, 2014 Auction: Exelon won 12 of 33 total tranches, the most of any winning bidder.[1228]

- October 23, 2014 Auction: Exelon won 5 of 17 total tranches, tied for most of any winning bidder.[1229]

In any event, Mr. Campbell's testimony concedes that his concern that the MSA could be considered to be a derivative is wrong. The language at issue, the definition of "Settlement Amount," deals with amounts that may be owed to or by the defaulting party.[1230] For an instrument to be a derivative, it must contain a "notional quality" or a "determinable amount, *i.e.*, an amount that can be determined from the face of the document."[1231] An instrument is not considered to be a derivative if it deals with normal purchase or sales, including contracts for goods or services to be delivered or sold.[1232]

Here, the MSA is not a derivative for at least two reasons. First, there is no determinable amount due. In definition of the Settlement Amount, the amount due or payable relates to a quantity of energy for the rest of the term as if the agreement had been fully performed. That amount is not known or knowable until some performance has been undertaken. Even then, the amount would be a projected amount not capable of prior calculation.

Second, the MSA relates to the procurement of energy which is to be sold by and delivered to the Companies by the SSO Supplier. It does not deal with goods sought to be

[1227] Company Ex. 109B; Hearing Tr. Vol. XXVI, p. 5274 (Campbell Cross).

[1228] Company Ex. 109C; Hearing Tr. Vol. XXVI, p. 5274 (Campbell Cross).

[1229] Company Ex. 109F; Hearing Tr. Vol. XXVI, p. 5275 (Campbell Cross).

[1230] Hearing Tr. Vol. XXVI, p. 5268-5269 (Campbell Cross).

[1231] *Id.* at 5269 (Campbell Cross).

[1232] *Id.* at 5269-5270 (Campbell Cross).

traded. The energy will be provided to end users. As such, the MSA qualifies as a normal sale and is not a derivative.

Mr. Campbell further admitted that on prior occasions Exelon had attempted to have the notional quantity language excluded from the MSA but that the Commission had declined to do so.[1233] Thus, Exelon's success in the Companies' recent SSO auctions belies any putative concerns regarding the notional quantity language set forth by Mr. Campbell in his testimony. And, indeed, the Commission has presumably recognized this fact as well, given its refusal to grant Exelon's request on prior occasions. Hence, Exelon's requested modification is meritless and Exelon has presented no new reasoning for the Commission to depart from its precedent on this issue.

Specific PNode IDs: As an initial matter, at hearing Mr. Campbell demonstrated almost complete ignorance regarding Exelon's proposed modification involving PNode IDs. Mr. Campbell admitted that he did not know what would happen after the initiation of contract if PNode IDs were changed within the definition of "FE Aggregate."[1234] Mr. Campbell further admitted that he did not know if the Companies' load is scheduled on a PNode basis.[1235] Notably, Mr. Campbell admitted that he did not even know if a list of PNode IDs would be accurate for the entire term of a contract or agreement.[1236]

Mr. Campbell's ignorance belies his suggestion, particularly given that the only testimony anyone who actually knew what a PNode ID was squarely rebuts Exelon's proposal here. At hearing, Mr. Stein testified that Exelon's desired PNode modification was not possible:

[1233] Hearing Tr. Vol. XXVI, pp. 5265-5267 (Campbell Cross).

[1234] Hearing Tr. Vol. XXVI, p. 5263 (Campbell Cross).

[1235] Hearing Tr. Vol. XXVI, p. 5263 (Campbell Cross).

[1236] Hearing Tr. Vol. XXVI, pp. 5263-5264 (Campbell Cross).

> A. ….If you mean the Pnode IDs that make up the FE Ohio residual aggregate ID, the one we are referencing now in the contract, the companies feel that suppliers have ways to manage that risk, and there is no way for the companies to pull out or create the specific values that make up the FE residual aggregate ID based on the individual p-nodes. In other words, PJM doesn't provide us information to be able to do that. So based on those two points we would -- we would not agree that there needs to be contractual language to have the suppliers only responsible for specific sets of PNode IDs under the residual aggregate.
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> *****
>
> Q. Okay. So if I understand your answer correctly, the problem is, one, you may not have the information from PJM in order to assign the PNode IDs and, two, it may be administratively difficult if you do?
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> A. Based on my previous answer, I think both those fit in my second point of *we don't have the information and PJM doesn't provide it.*[1237]

Hence, Exelon is requesting something that cannot be done and the Commission should reject Exelon's request accordingly.

PIPP change-in-law provision**:** At the hearing, Mr. Campbell could not provide any support for his requested PIPP change-in-law provision. As a matter of fact, because Department of Development already has the authority to remove PIPP load from SSO load,[1238] the risk that Exelon is concerned about cannot be avoided. Mr. Campbell admitted that he was unaware of any development that PIPP load could be removed from the SSO load without a change in applicable law, order, rule, or regulation.[1239] Mr. Campbell further admitted that, at the time of his deposition (and presumably when he drafted his testimony), he was also unaware if there was

[1237] Hearing Tr. Vol. V, pp. 934-935 (Stein Cross) (emphasis added).

[1238] R.C. 4928.54-.544.

[1239] Hearing Tr. Vol. XXVI, p. 5264 (Campbell Cross).

an agency or other state government entity that has the authority to remove the PIPP load from the SSO load.[1240]

H. Stipulated ESP IV's Resource Diversification Provisions Will Benefit Customers.

As discussed in the Companies' Initial Brief, the Companies in Stipulated ESP IV made a significant commitment to implement resource diversification initiatives, including an unprecedented commitment to establish a goal to reduce CO_2 emissions by at least 90% below 2005 levels by 2045, plus commitments to evaluate battery technology and to provide robust energy efficiency offerings and pursue renewable resources in Ohio[1241] ELPC, Sierra Club, OHA, OMAEG and OCC/NOAC argue that the Companies' resource diversification provisions do not provide any benefits to customers.[1242] Although ELPC asserts that the Commission can open dockets to explore the issues raised by the Companies' resource diversification provisions,[1243] ELPC (and the other parties) fail to recognize that there is no legal authority for the Commission to force the Companies to perform any of the resource diversification commitments contained in the Third Supplemental Stipulation. Put simply, the Companies (and its parent company FirstEnergy Corp.) made commitments that, as outlined below, are beneficial to customers and that they are otherwise not legally obligated to do. For that reason alone, the resource diversification provisions will benefit customers.

[1240] Hearing Tr. Vol. XXVI, p. 5264 (Campbell Cross). While the language proposed by Exelon, p. 76 of its Initial Brief is unacceptable, the Companies do note that subsequent to the hearing in this matter, the Staff filed a Report related to managing PIPP load relative to electric utilities' competitive bid processes, and while comments have been filed and additional comments are due on February 29, 2016, the matter has not yet been resolved. *See* Case No. 16-247-EL-UNC.

[1241] *See*, *generally*, Third Supp. Stip.; Mikkelsen Fifth Supp., pp. 3-6, 13; ("Mikkelsen First Supp."), pp. 11-12; Companies' Initial Brief, p. 7.

[1242] ELPC Brief, pp. 51-52; Sierra Club Brief, pp. 118-121; OHA Brief p. 9; OMAEG Brief, pp. 76-77; OCC/NOAC Brief, p. 156.

[1243] ELPC Brief, p. 52.

Moreover, the resource diversification provisions of the Third Supplemental Stipulation promote a number of state policies expressed in Section 4928.02 including:

> (A) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service;
>
> (C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities;
>
> (D) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand- side management, time-differentiated pricing, waste energy recovery systems, smart grid programs, and implementation of advanced metering infrastructure;
>
> (E) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote both effective customer choice of retail electric service and the development of performance standards and targets for service quality for all consumers, including annual achievement reports written in plain language; and
>
> (J) Provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates.

By promoting these state policies, the resource diversification provisions, as a whole, benefit customers. Finally, as discussed specifically below, each type of provision has its own unique benefits to customers. For those reasons, the Commission should consider the benefits that the resource diversification benefits provides to customers and approve the Companies' Stipulated ESP IV.

1. CO_2 reduction goal

OMAEG argues that this goal is illusory and not a firm commitment.[1244] ELPC and Sierra Club are concerned this commitment to establish a goal lacks detail and provisions for enforceability such as a penalty.[1245] ELPC further contends that FirstEnergy Corp.'s goal to reduce CO_2 emissions by at least 90% below 2005 levels by 2045 "could be very ambitious."[1246] Yet ELPC's witness agreed that having a fuel diversification strategy and updating that practice regularly was a good business practice that should yield benefits for customers.[1247] As discussed by Company witness Mikkelsen, the Companies will file a report with the Commission by November 1, 2016 highlighting their then-current carbon reduction strategy and will continue to file reports with the Commission on the then-current status of carbon reduction efforts every five years through 2045.[1248] These efforts could include energy efficiency efforts that replace emissions from fossil-fuel fired generating facilities.[1249] What these intervenors overlook is that FirstEnergy Corp. and its affiliates are, in fact, making a commitment; a commitment that they had not obligation to provide. As Sierra Club correctly asserts, neither FirstEnergy Corp. nor FES are subject to the jurisdiction of the Commission.[1250] Yet they have committed to meet ambitious CO_2 reduction goals that they have no legal obligation to do. Indeed, FirstEnergy Corp. will strive to attain this goal even if the U.S. EPA's CPP is overturned by court order.[1251] Last, as Ms. Mikkelsen testified:

[1244] OMAEG Brief, p. 89-90

[1245] ELPC Brief, p. 51; Sierra Club Brief p. 119.

[1246] Rabago Direct, p. 15.

[1247] Hearing Tr. Vol. XXXVIII, p. 8180 (Rabago Cross).

[1248] Hearing Tr. Vol. XXXVI, pp. 7634-35, 7644-45 (Mikkelsen Cross).

[1249] Hearing Tr. Vol. XXXVI, p. 7635 (Mikkelsen Cross).

[1250] Sierra Club Brief, p. 119

[1251] Third Supp. Stip., Section V.E.1.

> While the Third Supplemental Stipulation and Recommendation does not include a penalty provision, should FirstEnergy Corp. fail to meet this CO-2 emissions reduction goal, the company takes its regulatory commitments very seriously, and I believe a pattern of failure to meet your regulatory commitments without good cause shown would have a very chilling effect on the companies' ability to work successfully with its regulators in a going-forward basis.[1252]

Thus, the CO_2 carbon reduction goal contributes value to Stipulated ESP IV, is a firm commitment with serious consequences for noncompliant and does not violate any important regulatory principle or practice.

2. Battery resources

The Companies will evaluate investing in battery resources and technology contingent upon Commission approval of cost recovery for such investments.[1253] According to the United States Department of Energy, as of December 2013, there was only 304 MW of battery storage in the entire United States.[1254] Given this lack of battery storage, it is important for customers that this technology is evaluated for future investments. The Companies have been following battery resources along and propose to evaluate whether there is a benefit to the Companies' distribution system to install battery resources – another commitment that the Companies are not legally obligated to undertake.[1255] And, as OCC/NOAC indicate, this evaluation will not cost customers anything until a project is actually approved by the Commission and implemented.[1256]

[1252] Hearing Tr. Vol. XXXVI, p. 7529 (Mikkelsen Cross).

[1253] Third Supp. Stip., Section V.E.2; Hearing Tr. Vol. XXXVII, pp. 7775-76 (Mikkelsen Cross).

[1254] Grid Energy Storage, U.S .Department of Energy, December 2013, p. 11 administratively noticed in Hearing Tr. XL, pp. 8468-69.

[1255] Hearing Tr. XXXVII, p. 7776 (Mikkelsen Cross).

[1256] OCC/NOAC Brief, p. 157.

3. 100 MW of wind or solar

Based on what it believes is "common sense" only, ELPC asserts that the Companies have not shown that the renewable provisions will provide any benefits.[1257] Citing to MAREC witness Burcat, ELPC presumes that the Companies' commitment would not provide financial benefits for renewable development.[1258] However, the renewable provision of the Third Supplemental Stipulation, if triggered, will provide "large-scale financing" and "some meaningful degree of certainty" that MAREC witness Burcat states is needed. If the provision is triggered, the Companies will file for approval to procure the requisite renewable energy and the provision further provides for a cost recovery mechanism on a nonbypassable basis. Indeed, Section V.E.4. is consistent with the testimony of ELPC witness Rábago, who supports market-based development of renewable resources in the first instance, but who also believes government incentives are necessary at times to overcome market failures.[1259]

RESA complains the Commission should not approve the renewable provisions of the Third Supplemental Stipulation because it is "a giveaway provision"[1260] RESA also believes that the Companies should not be allowed to own or fund procurement of renewable resources under a non-bypassable rider.[1261] However, as Mr. Bennett admits, there is a law that allows the utilities to own generation under certain scenarios.[1262] Specifically, Section 4928.143(B)(2)(b) permits the party to own generation upon the showing of need. And Section 4928.143(B)(2)(a) permits an EDU to recover the costs of purchased power. This provision of the Third

[1257] ELPC Brief, p. 52.

[1258] ELPC Brief, p. 52.

[1259] Hearing Tr. Vol. XXXVIII, pp. 8184-85 (Rabago Cross).

[1260] RESA Brief, pp. 48-49.

[1261] RESA Brief, p. 49.

[1262] Hearing Tr. Vol. XL, p. 8510 (Bennett Cross).

Supplemental Stipulation will be triggered to the extent that Staff finds it helpful to comply with a federal or state law or rule, and such law or rule has not led to the development of new renewable energy resources.[1263] RESA's argument is without merit.

Sierra Club criticizes the Companies' renewable energy provision. Sierra Club complains that there are too many conditions.[1264] However, Sierra Club again fails to recognize that the Companies are not legally obligated to procure renewable energy. The Companies are making a firm commitment, at Staff's request, to request permission from the Commission to procure 100 MW of new Ohio wind or solar resources something the Companies are currently not legally obligated to do[1265] As Ms. Mikkelsen testified, "Once the staff asks the Companies, they are obligated to file."[1266] While OMAEG asserts that the CPP is not considered a future law that would trigger this provision, the state's plan to meet those laws would be.[1267] But, as Ms. Mikkelsen testified, this state plan may not foster the development of renewable resources because Staff may want a utility to take action and not rely on merchant developers (who are driven by price signals and the ability to recover investment) to meet the state's goals.[1268]

Citing to OMAEG witness Seryak's unsubstantiated testimony, OCC/NOAC further criticize the Companies' renewable energy provision stating that businesses could be paying twice for renewable energy.[1269] Likewise, OCC/NOAC, without any support, state that the RPS

[1263] Third Supp. Stip., Section V.E.4.; Mikkelsen Fifth Supp., p. 4.

[1264] Sierra Club Brief, p. 120.

[1265] Hearing Tr. Vol. XXXVI, p. 7540 (Mikkelsen Cross).

[1266] Hearing Tr. Vol. XXXVI, p. 7543 (Mikkelsen Cross).

[1267] OMAEG Brief, p. 90; Hearing Tr. Vol. XXXVI, pp. 7541-7542 (Mikkelsen Cross).

[1268] Hearing Tr. Vol. XXXVI, p. 7546 (Mikkelsen Cross).

[1269] OCC/NOAC Brief, pp. 159-160.

marketplace often results in lower prices and that "Rider ORR"[1270] will limit the number of buyers and sellers.[1271] This argument makes no sense especially given that the Companies will procure the renewable energy and renewable energy credits and sell them into the market. Rider ORR will also be a charge or a credit depending on the price. Moreover, the renewable energy provision will trigger when market forces fail to provide renewable resources helpful for the state to comply with a future federal or state law or rule. OCC/NOAC also miss this important precondition when it attempts to argue that the procurement commitment does not represent an incremental benefit over what the market otherwise would develop. The Companies' procurement will not be market disruptive - in fact, it will be an incremental benefit - because the market itself would have failed to provide these necessary resources. For all of these reasons, the renewable energy provisions provide a benefit to customers.

4. Stipulated ESP IV's energy efficiency provisions will benefit customers and are in the public interest.

Although ELPC criticizes the EE/PDR commitments in Section V.E.3 of the Stipulation,[1272] ELPC's own witness Rábago supports advancing energy efficiency efforts in Ohio.[1273] He also agrees with the Signatory Parties that it will be beneficial for customers to have a proceeding in which interested parties can address the costs and benefits of EE/PDR in the Companies' service territories, as the Companies have committed to do in Section V.E.3. of the Third Supplemental Stipulation.[1274] Although Mr. Rábago questioned whether the Third Supplemental Stipulation includes an "enforceable commitment to any quantitative savings

[1270] The Companies believe that OCC/NOAC incorrectly referenced Rider ORR when it meant to say the renewable energy provisions because Rider ORR is simply the cost recovery mechanism.

[1271] OCC/NOAC Brief, p. 160.

[1272] ELPC Brief, pp. 49-50.

[1273] Hearing Tr. Vol. XXXVIII p. 8182 (Rabago Cross).

[1274] Hearing Tr. Vol. XXXVII, p. 8182 (Rabago Cross).

benchmark,"[1275] he was not aware that Section 4928.66 already provides that enforceable commitment to statutory benchmarks.[1276] He also suggested that the Third Supplemental Stipulation should preclude the Companies from counting energy efficiency savings resulting from independent customer action (presumably toward the 800,000 MWh of annual savings in Section V.E.3.b.), but Section 4928.662(A) specifically authorizes the Companies to count savings achieved through customer actions.[1277]

ELPC and OCC/NOAC oppose the inclusion of energy efficiency savings resulting from the Companies' Customer Action Program in the calculation of shared savings.[1278] Under the Third Supplemental Stipulation, cost effective energy efficiency programs shall be eligible for shared savings.[1279] Thus, if savings resulting from the Customer Action Program are cost effective, which the Companies believe will be the case,[1280] then it is reasonable to incent the Companies to recognize additional energy efficiency savings obtained through this program by sharing a portion of those savings with the Companies.

ELPC and OCC/NOAC also criticize the increase of the annual shared savings cap from $10 million to $25 million in Section V.E.3.d.,[1281] but that criticism is based on a misunderstanding of shared savings in the context of utility-sponsored EE/PDR portfolio plans. The Companies are eligible for shared savings only for energy efficiency savings achieved in

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[1275] Rábago Direct, p. 16.

[1276] Hearing Tr. Vol. XXXVIII, pp. 8182-83 (Rabago Cross).

[1277] *See* Hearing Tr. XXXVII, pp. 7861-65 (Company witness Mikkelsen discussing Commission-approved Customer Action Program)

[1278] ELPC Brief, p. 50; OCC/NOAC Brief, p. 68.

[1279] Third Supp. Stip., Section V.E.3.d.

[1280] Hearing Tr. Vol. XXXVII, p. 7866 (Mikkelsen Cross).

[1281] ELPC Brief, p. 50; OCC/NOAC Brief, p. 68.

excess of the statutory benchmarks and only for cost-effective programs.[1282] And an increase in the savings cap to $25 million cap for the Companies is reasonable given that, even at $25 million, amounts to only $8.33 million per company, which is still less on a per operating company basis than other shared savings caps approved by the Commission.[1283] ELPC does not find fault with the amount of shared savings the Company could receive, only that the amount is predetermined.[1284] ELPC's witness recognized, however, that shared savings programs are commonly used and can have value.[1285] OCC/NOAC suggest that increasing the cap on shared savings is intended to benefit the Companies' shareholders, even going so far as to accuse Staff of supporting this provision specifically to benefit the Companies' shareholders.[1286] What OCC/NOAC ignore in its rush to judgment is that additional savings achieved by the Companies above the existing $10 million cap means that the Companies' customers achieved substantially more savings. As the Commission has found, "the purpose of a shared savings mechanism is to encourage utilities to exceed benchmarks" as a benefit to the Companies' customers.[1287] The Companies' shared savings mechanism has a top-tier incentive of 13%, which signifies that every 13 cents earned by the Companies for exceeding the statutory benchmarks also generates 87 cents in savings for the Companies' customers.[1288] OCC/NOAC's witness was ignorant of the methodology used to calculate shared savings and of the amount of savings the Companies' customers would receive if the Companies were able to earn savings up to the new $25 million

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[1282] Third Supp. Stip., Section V.E.3.d.; Hearing Tr. Vol. XXXVI, p. 7639 (Mikkelsen Cross).

[1283] Case No. 11-5568-EL-POR, Finding and Order, p. 8 (March 21, 2012).

[1284] Rábago Direct, p. 17.

[1285] Hearing Tr. Vol. XXXVIII, pp. 8183-84 (Rabago Cross).

[1286] Kahal Second Supp., p. 17; Hearing Tr. Vol. XXXVIII, p. 8234 (Kahal Cross).

[1287] Case No. 12-2190-EL-POR, *et al.*, Finding and Order, p. 16 (Nov. 20, 2014).

[1288] *See* Case No. 12-2190-EL-POR, *et al.*, Opinion and Order, p. 15 (Mar. 20, 2013).

cap in each year of Stipulated ESP IV.[1289] Thus, it is no surprise that the Signatory Parties recommend approval of the cap increase in order to benefit the Companies' customers. OCC/NOAC's and ELPC's criticisms of the increase in the shared savings cap lack merit.

I. Grid Modernization Benefits Customers.

The Companies committed to file within 90 days of the filing of the Third Supplemental Stipulation a grid modernization business plan.[1290] The Companies are not legally obligated to file such a plan and Staff specifically testified that it wanted the Companies to file this plan.[1291] Moreover, as discussed above, the promotion of smart grid and advanced metering infrastructure initiatives is a specifically enumerated State policy.[1292] Indeed, certain parties like ELPC and OHA generally support such initiatives.[1293]

OMAEG criticizes the Companies' Stipulated ESP IV because the Companies did not provide specific costs or benefits associated with the future grid modernization initiative.[1294] Without citing to any authority, OCC/NOAC argue that the Companies' proposal to file a grid modernization business is outside the scope of this proceeding and that the Companies can file one in the future.[1295] OCC/NOAC also criticize the Companies for not providing precise details in this case regarding the business plan.[1296] Citing to Mr. Rabago's testimony, OCC/NOAC

[1289] Hearing Tr. Vol. XXXVIII, pp. 8238-39 (Kahal Cross).

[1290] Third Supp. Stip., Section V.D.

[1291] Benedict Direct, pp. 2-3 .

[1292] R.C. 4928.02(D).

[1293] Hearing Tr. Vol. XXXVIII, pp. 8180-81, 8188-89 (Kahal Cross); OHA Brief, p. 8.

[1294] OMAEG Brief, p. 89

[1295] OCC/NOAC Brief, p. 154.

[1296] OCC/NOAC Brief, p. 154. Citing to discovery requests that are not in the record, OCC/NOAC states that the Companies "refused to provide documents in this proceeding relating to Volt Var or the grid modernization business plan. OCC/NOAC fails to mention, however, that the Attorney Examiner specifically denied ELPC's motion to compel on this point. Hearing Tr. XXXVI, p. 7505 (Rose Re-Cross). Therefore, the Commission should disregard OCC/NOAC's editorial comments in this regard.

assert that parties should have the benefit of a full record and the right to participate in any grid modernization proceeding.[1297] OMAEG and OCC/NOAC miss the point. Those specifics are to be developed and addressed in a future proceeding where they will have every opportunity to participate. In Section V.D. of the Third Supplemental Stipulation, the Companies have committed "to empower consumers through grid modernization initiatives that promote customer choice in Ohio."[1298] The anticipated business plan will address multiple potential initiatives and include a timeline for the Companies' to achieve full smart meter implementation.[1299] While OMAEG and OCC/NOAC want to see more detail, the obvious reason for the lack of detail is that the business plan will not be filed until later and did not exist at the time of the hearing.[1300] As Ms. Mikkelsen testified and all Signatory Parties agree, that filing will merely initiate an extended review process:

> [T]he collective recommendation of all of the signatory parties to the stipulation . . . is that the companies should bring forward within 90 days a business plan associated with Smart Grid, advanced metering, distribution automation, Volt/Var control, and then all parties, all interested parties, can participate in the vetting of that business case in order to inform the Commission's decision about how, if at all, the companies should proceed with grid modernization.[1301]

OMAEG and OCC/NOAC desire to see more specifics about future grid modernization initiatives can be satisfied in that future proceeding.

[1297] OCC/NOAC Brief, p. 154-155.

[1298] Third Supp. Stip., Section V.D.1.

[1299] Third Supp. Stip., Section V.D.2; Hearing Tr. Vol. XXXVI, p. 7628 (Mikkelsen Cross) (business plan will include smart meter budget).

[1300] Hearing Tr. Vol. XXXVII, p. 7847 (Mikkelsen Cross).

[1301] Hearing Tr. Vol. XXXVI, p. 7624 (Mikkelsen Cross).

OHA, OMAEG and OCC/NOAC criticize the ROE for grid modernization established by the Third Supplemental Stipulation[1302] and claim that the "ROE established by the [Third Supplemental Stipulation] is higher than the currently established ROE for grid modernization."[1303] OCC/NOAC also believe the grid modernization initiative is "wrong" because OCC/NOAC allege that it fixes the return on equity for grid modernization investments to be recovered through Rider AMI.[1304] In fact, the ROE is not fixed, but initially would be set at 10.88% based on the current FERC-approved ROE for ATSI of 10.38% plus a fifty-basis-point incentive mechanism.[1305] The ROE will be adjusted as ATSI's ROE is adjusted in the future.[1306] All Signatory Parties agreed that this ROE formula is appropriate in other to incent grid modernization investment in Ohio over other potential investments.[1307] Basing the ROE formula on the ATSI ROE serves a valuable purpose in that if the ATSI ROE declines in future years the incentive to favor Ohio investment will not grow unnecessarily but will remain at fifty basis points. Further, the Companies will credit to customers any operational savings that are produced by the investment, *e.g.*, reduced meter reading expenses, against costs.[1308] Thus, the Commission should reject OHA, OMAEG and OCC/NOAC's objection to the ROE formula for any grid modernization initiatives approved by the Commission in a future proceeding.

[1302] OHA Brief, p. 8.

[1303] OMAEG Brief, p. 89; OCC/NOAC Brief, p. 155.

[1304] OCC/NOAC Brief, p. 155, Rabago Direct, p. 14.

[1305] Third Supp. Stip., Section V.D.3.; Hearing Tr. Vol. XXXVI, pp. 7631-32 (Mikkelsen Cross).

[1306] Third Supp. Stip., Section V.D.3.; Hearing Tr. Vol. XXXVII, p. 7775 (Mikkelsen Cross).

[1307] Hearing Tr. Vol. XXXVII, p. 7775 (Mikkelsen Cross).

[1308] Third Supp. Stip., Section V.D.3.

IV. STIPULATED ESP IV DOES NOT VIOLATE ANY IMPORTANT REGULATORY PRINCIPLE OR PRACTICE

The Companies' Initial Brief demonstrated how Stipulated ESP IV does not violate any important regulatory principle or practice and furthers state policies and goals.[1309] Intervenors opposed to Stipulated ESP IV mostly have focused on the Commission's legal authority to approve Rider RRS, raising many of the same arguments already rejected by the Commission in the AEP ESP3 proceeding and Duke's ESP4 proceeding. Those arguments are addressed immediately below in Sections IV.A. through IV.J. and should meet the same fate here.

Notably, intervenors' legal objections to Stipulated ESP IV are not limited to Rider RRS but also include Riders ELR, DCR and GCR.[1310] They also object to discrete portions of the first Stipulation and the Third Supplemental Stipulation.[1311] Each of these objections is addressed and disposed of later in this section of the Companies' Reply Brief.

A. Rider RRS Is Authorized By Section 4928.143(B)(2)(d).

Several opponents of Rider RRS claim that it is not authorized by Section 4928.143(B)(2)(d).[1312] For some, their heart is not in the argument, as demonstrated by their failure to offer anything more than conclusory statements.[1313] This is likely because the Commission on two previous occasions already has determined that retail stability riders

[1309] Companies' Initial Brief, pp. 113-48.

[1310] *See* Sections IV.K through IV.N., below.

[1311] *See* Sections IV.O. through IV.S., below.

[1312] Sierra Club Brief, pp. 7-12; EPSA/P3 Brief, pp. 14-15; Exelon Brief, pp. 14-16; P4S Brief, pp. 10-11; NOPEC Brief, pp. 18-26; CMSD Brief, pp. 7-16. Although OCC/NOAC does not cite to R.C. 4928.143(B)(2)(d) once in its brief, it does argue that Rider RRS would not have the effect of stabilizing or providing certainty regarding retail electric service. OCC/NOAC Brief, pp. 83-92.

[1313] *See* EPSA/P3 Brief, pp. 14-15; P4S Brief, pp. 10-11.

supported by PPAs are authorized by Section 4928.143(B)(2)(d).[1314] As explained in the Companies' Initital Brief, Rider RRS similarly is authorized by Section 4928.143(B)(2)(d).[1315]

1. Rider RRS is a term, condition or charge.

No party contests that Rider RRS is a term, condition or charge. Sierra Club and CMSD agree that it is.[1316] Rider RRS satisfies this requirement of Section 4928.143(B)(2)(d).

2. Rider RRS relates to limitations on customer shopping for retail electric generation service, bypassability, and default service.

a. Rider RRS relates to limitations on customer shopping for retail electric generation service.

Several opponents of Rider RRS challenge the Commission's decision in the *AEP ESP3* Order and the *Duke ESP4* Order that a PPA-type rider functions as a financial restraint on shopping for retail electric generation service.[1317] While these parties complain that the Commission is reading the word "financial" into the statute, the irony is that they are asking the Commission to narrow the statute's meaning unnecessarily by reading the word "physical" into the statute. The statute does not specify what types of limitations on customer shopping will qualify. A general term like "limitation" necessarily includes subcategories that constitute different types of limitations. Thus, the Commission has reasonably interpreted this language to include both physical and financial limitations. Limiting this language to only physical limitations would violate the interpretational maxim that courts "must give effect to the words

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[1314] *In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service*, Case No. 14-841-EL-SSO, Opinion and Order, pp. 42-48 (April 2, 2015) ("*Duke ESP4* Order"); *AEP ESP3 Order*, pp. 19-27.

[1315] Companies' Initial Brief, pp. 113-24.

[1316] Sierra Club Brief, p. 7; CMSD Brief, p. 9.

[1317] *See, e.g., AEP ESP3* Order, p. 22. *See* NOPEC Brief, pp. 21-23; P4S Brief, p. 11; CMSD Brief, pp. 9-12.

used, making neither additions nor deletions from words chosen by the General Assembly."[1318] By arguing that "limitations on customer shopping" should be modified to read "***physical*** limitations on customers shopping," these parties are making additions to the words chosen by the General Assembly.

Sierra Club also hopes to limit the scope of Section 4928.143(B)(2)(d) by arguing that "limitations on customer shopping for retail electric generation service" requires that the limit be on the supply of electricity.[1319] This is simply another way of arguing that the statute requires a physical limitation and not a financial limitation. The Signatory Parties agree, as pointed out by Sierra Club in its brief, that Rider RRS does not in any way limit a customer's ability to shop, and does not negatively impact retail competition or SSO auctions.[1320] As proposed by the Companies, the physical supply to customers for their retail electric service will come from either the SSO auction or a CRES provider. Rider RRS will provide an additional, but separate, function: to provide rate stability through the financial hedge design. Simply because Rider RRS does not physically limit shopping does not mean that the Commission cannot view it as a limitation. The General Assembly did not specify that only some types of "limitations on customer shopping" qualify. To the contrary, *any* type of limitation qualifies.

Similarly, CMSD complains that Section 4928.143(B)(2)(d) does not use the words "hedging arrangements."[1321] But the General Assembly is not required to anticipate all possible types of retail stability charges that may be developed. The question is whether the words used encompass the proposed Rider RRS. And given the historical circumstances that prompted the

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[1318] *In re Columbus Southern Power Co.*, 138 Ohio St.3d 448, 2014-Ohio-462, 8 N.E.3d 863, ¶ 26.

[1319] Sierra Club Brief, p. 9.

[1320] Third Supp. Stip., SectionV.L.2.

[1321] CMSD Brief, pp. 10-11.

General Assembly to enact Section 4928.143(B)(2)(d), there can be no doubt that a PPA-type rider like Rider RRS is encompassed within the words used because it provides retail rate stability. The General Assembly enacted S.B. 3 at a time when it was hoped that markets would lead to a new era of stable, low-cost electric generation pricing. Some eight years later, the General Assembly realized that markets are volatile and can produce both high and low prices. As a result, the General Assembly authorized "security" plans that could include terms, conditions or charges relating to numerous options available to provide some stability to retail electric service. The General Assembly required only that the term, condition or charge "relate to" the list of options to convey even broader latitude and discretion to the Commission.[1322] Given that a hedge against electric prices is an obvious retail rate stability option that goes to the core concern that motivated the General Assembly to enact Division (B)(2)(d), it should be no surprise that Rider RRS fits under more than one of the options in the statute.

b. **Rider RRS relates to bypassability.**

The Companies explained in their Initital Brief how Rider RRS relates to bypassability.[1323] NOPEC and P4S rely on the Commission's *AEP ESP3* Order as support against the Rider RRS relating to bypassability.[1324] The Commission's narrow reading of "bypassability" in the *AEP ESP3* Order is an example of the Commission not giving effect to the words used. Indeed, the Commission correctly interpreted "bypassability" in an earlier decision approving a nonbypassable stability charge for DP&L.[1325] As the Commission explained:

[1322] The statute "limits the *type* of categories a plan may include, while the phrase 'without limitation' *allows as many or as much* of the listed categories as the commission finds reasonable[.]" *Columbus Southern Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 33 (emphasis in original).

[1323] Companies' Initial Brief, p. 118.

[1324] NOPEC Brief, pp. 19-20; P4S Brief, pp. 10-11.

[1325] *See In the Matter of the Application of The Dayton Power and Light Company for Approval of its Electric Security Plan*, Case No. 12-426-EL-SSO, Opinion and Order, pp. 20-21 (Sept. 4, 2013) ("*DP&L ESP2* Order").

> Section 4928.142(B)(2)(d), Revised Code, authorizes electric utilities to include in an ESP terms related to bypassability of charges to the extent that such terms have the effect of stabilizing or providing certainty regarding retail electric service. The Commission finds that based upon the record of this proceeding, the SSR should be nonbypassable. Both shopping and non-shopping customers benefit from the existence of the standard service offer, which is available even if market conditions become unfavorable for retail shopping customers over the term of the ESP. Thus, the Commission believes that the second criterion of Section 4928.143(B)(2)(d), Revised Code, is satisfied.

The Commission asked in the *DP&L ESP2* Order whether both shopping and non-shopping customers will benefit, which is equally true in this case. Thus, based on the plain language of Division (B)(2)(d), Rider RRS relates to bypassability.

c. **Rider RRS relates to default service.**

NOPEC argues that Rider RRS does not relate to default service, narrowly construing the term "default service" to mean only the involuntary service provided under Section 4928.14.[1326] Similarly, P4S argues that only a charge associated with an event of default under Section 4928.141 can relate to default service.[1327] Yet, these narrow readings of "default service" in Division (B)(2)(d) are not the Commission's reading, or for that matter a common reading, of the term. As discussed in the Companies' initial brief, the Commission previously has found that "default service" as used in Division (B)(2)(d) means SSO service.[1328] Customers default to the Companies' SSO service, so default service is synonymous with SSO service.[1329] And Rider RRS relates to the Companies' proposed default service because the rider is designed to mitigate the long-term risk of wholesale market price increases that will be incorporated directly into the SSO via the competitive procurement process.

[1326] NOPEC Brief, p. 20.

[1327] P4S Brief, p. 11.

[1328] Companies' Initial Brief, pp. 119.

[1329] *See* R.C. 4928.14.

3. Rider RRS would have the effect of stabilizing or providing certainty regarding retail electric service.

A handful of opponents argue that Rider RRS cannot be authorized under Section 4928.143(B)(2)(d) because they believe it would not have the effect of stabilizing or providing certainty regarding retail electric service.[1330] The Companies fully addressed these criticisms in their Initial Brief.[1331] In addition, the Companies addressed above the question of whether Rider RRS will have the effect of stabilizing or providing certainty regarding retail electric service.[1332] Importantly, the Commission also has fully addressed these criticisms and found them lacking in the *AEP ESP3* Order and *Duke ESP4* order.[1333] As noted in the *AEP ESP3* Order, a retail stability charge that is designed to mitigate retail electric generation price increases would have the effect of stabilizing retail electric service.[1334] Rider RRS serves that purpose by acting as a counter-cyclical hedge to protect customers against wholesale market volatility over the long run.

Sierra Club questions whether Rider RRS relates to "retail electric service," which Sierra Club interprets as the supply of generation to retail customers.[1335] Sierra Club believes a retail stability rider can be approved under Division (B)(2)(d) only if it affects SSO supply.[1336] Yet, the term "retail electric service" is much broader than Sierra Club suggests. The Commission has approved a retail stability charge under Division (B)(2)(d) on the basis that the charge would

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[1330] Exelon Brief, pp. 15-16; NOPEC Brief, pp. 23-26; OCC/NOAC Brief, pp. 83-92; Sierra Club Brief, pp. 10-12; CMSD Brief, pp. 12-16.

[1331] Companies' Initial Brief, pp. 120-22.

[1332] *See* Section III.A., *supra*.

[1333] *AEP ESP3* Order, p. 21; *Duke ESP4* Order, p. 44.

[1334] *AEP ESP3* Order, p. 21. The Companies need not show that Rider RRS is necessary to stabilize retail electric service, only that it would have a stabilizing effect. *See In re Columbus Southern Power Co.*, 138 Ohio St.3d 448, 2014-Ohio-462, 8 N.E.3d 863, ¶ 28.

[1335] Sierra Club Brief, pp. 8-9.

[1336] *See id.*

support financial integrity of an EDU's distribution service, provide rate stability and certainty through CRES services (which are "retail electric service"), and stabilize non-fuel generation charges.[1337] In the same way, Rider RRS will provide stability and certainty not only with regard to SSO and CRES services, but also with regard to the Companies' distribution service through its impact on reliability and resource diversity.

Although Rider RRS opponents complain that Rider RRS cannot stabilize rates in the short-term when it is a charge to customers,[1338] this reads the word "charge" entirely out of the statute. What Division (B)(2)(d) contemplates is that customers pay a charge in exchange for stability. Like insurance, stability and reliability are not free. In each year Rider RRS is a charge, customers continue to receive the benefit of low energy prices while also receiving price protection, reliability and resource diversity.

NOPEC's reliance on its existing nine-year aggregation contract does not advance its argument.[1339] NOPEC's contract is not a hedge at all, but simply a discount off the SSO price-to-compare. As the SSO price increases, so will NOPEC's contract price. NOPEC's contract does not provide customers a counter-cyclical hedge in the way that Rider RRS is designed to do.[1340] Moreover, customers participating in NOPEC's aggregation can opt out at least every three years,[1341] which would expose those customers to the same volatility and double-digit price

[1337] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 11-346-EL-SSO, Opinion and Order, p. 31 (Aug. 8, 2012).

[1338] *See*, *e.g.*, CMSD Brief, p. 15.

[1339] *See* NOPEC Brief, pp. 25-26.

[1340] *See also* Mikkelsen Rebuttal, p. 5 (even fixed-price contracts do not function as a hedge because a hedge would move counter to market and mitigate the impact of swings in the market).

[1341] O.A.C. 4901:1-21-17(A)(5).

increases seen by other customers.[1342] Following the expiration of the NOPEC contract, customers "would be subject to the full impact of market prices and conditions at the time of their contract expiration."[1343] Rider RRS provides stability and certainty to all customers, including customers currently on aggregation contracts.

B. Rider RRS Is Authorized By Section 4928.143(B)(2)(i).

Only NOPEC's brief mentions the Companies' request to approve Rider RRS as an economic development program.[1344] NOPEC jumps to the conclusion that Rider RRS cannot be an economic development program because there is insufficient proof that the Plants will retire without Rider RRS.[1345] This is a fallacy advanced by several parties throughout this proceeding. Economic development programs promote economic development. They do not require proof a company or facility will shut down "but for" the economic development program. Rather, programs that maintain employment or retain industry are (and have been) properly considered to be economic development programs.

Take, for example, the economic development programs in the Companies' ESP I.[1346] Rider ELR was approved as an economic development program without any proof that all Rider ELR customers will cease operations without it. The Companies' $7.5 million economic development contribution to projects identified by OMA did not require proof that OMAEG's members would cease operations without that contribution. The same is true of the economic

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[1342] *See* Mikkelsen Rebuttal, p. 4; Hearing Tr. Vol. XXXIV, p. 7146 (Mikkelsen Rebuttal Cross correcting 35% to 32%); Hearing Tr. Vol. XXV, pp. 4955-56 (customers rolling off contracts can experience price increases of up to 30%).

[1343] Mikkelsen Rebuttal, p. 6.

[1344] NOPEC Brief, p. 19.

[1345] NOPEC Brief, p. 19 fn. 62.

[1346] *See* Case No. 08-935-EL-SSO, Opinion and Order, pp. 13-14 (Mar. 25, 2009).

development programs approved for the first time in the Companies ESP II.[1347] The credits in Rider EDR to help domestic automakers and provide funding to the Cleveland Clinic could not have been approved if the Companies had to affirmatively demonstrate as a precondition of the Commission's approval of Rider EDR that the automakers and the Clinic would have closed but for those credits. Of course, no such precondition applies to economic development programs approved under Division (B)(2)(i) of the ESP statute. To the contrary, economic development programs often maintain existing economic benefits in Ohio or encourage expanded investment. For example, the Ohio Development Services Agency has as its responsibility "the retention, development, and expansion of industrial and commercial facilities in this state."[1348]

The Companies' Initial Brief explained why the Economic Stability Program, operating through Rider RRS, qualifies as an economic development program.[1349] In particular, Rider RRS will mitigate long-term retail price increases while assuring continued operation of the Plants and their continued positive impact on economic development. Rider RRS also maintains resource diversity and reliability, which also provides economic development benefits through a measure of rate stability.[1350] In addition, Rider RRS avoids the risk that, if the Plants do shut down, customers would shoulder transmission costs of between $1.7 and $4.1 billion.[1351] If the Commission agrees that reliability, resource diversity, rate stability and cost avoidance offer economic development benefits, the Commission has the authority to approve Rider RRS.

[1347] *See* Case No. 10-388-EL-SSO, Opinion and Order, p. 27 (Aug. 25, 2010).

[1348] R.C. 122.04.

[1349] Companies' Initial Brief, pp. 122-24.

[1350] Moul Direct, pp. 6-10; Makovich Supp., pp. 3-4; Hearing Tr. Vol. III, p. 515 (Mikkelsen Cross).

[1351] Phillips Supp., pp. 6-10; Mikkelsen Second Supp., pp. 6-11 and Attachment EMM-2.

C. Rider RRS Does Not Conflict With Section 4928.02(H).

Contrary to claims of OCC/NOAC and others,[1352] approval of Rider RRS will not violate Section 4928.02(H). Section 4928.02(H) is an expression of the state's policy to:

> Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates.[1353]

Rider RRS does not violate Section 4928.02(H) for at least three reasons.

First, Rider RRS is authorized by Section 4928.143(B)(2)(d). As long as a provision fits within one of the nine categories, it is authorized by statute.[1354] Intervenors ignore that Section 4928.143(B)(2)(d) also expresses the policy of the state to support stability and certainty in the provision of retail electric service. As explained by the Supreme Court of Ohio, Section 4928.143(B)(2) "allows unlimited inclusion of listed items."[1355] Any of these nine items may be included in an Electric Security Plan "[n]otwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code."[1356] Thus, the Commission may approve Rider RRS as a component of the Companies' Stipulated ESP IV under Section 4928.143(B) notwithstanding any alleged conflict with Section 4928.02.

Second, and related to the first, the policies in Section 4928.02 are guidelines, not requirements. As the Supreme Court of Ohio stated in *In re Columbus S. Power Co.*, 128 Ohio

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[1352] *See* OCC/NOAC Brief, pp. 114-17; Exelon Brief, pp. 17-18; OMAEG Brief, pp. 68-70; EPSA/P3 Brief, pp. 17-18; P4S Brief, p. 13; CMSD Brief, pp. 26-28; NOPEC Brief, pp. 42, 47-48.

[1353] R.C. 4928.02(H).

[1354] *Columbus Southern Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 33.

[1355] *Id.*

[1356] R.C. 4928.143(B).

St. 3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 62, the policies in Section 4928.02 do not require the Commission to do anything:

> [S]uch policy statements are "guideline[s] for the commission to weigh" in evaluating utility proposals to further state policy goals, and it has been "left . . . to the commission to determine how best to carry [them] out." *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 125 Ohio St.3d 57, 2010 Ohio 134, 926 N.E.2d 261, ¶39-40.

Even if Rider RRS conflicted with Sectioin 4928.02(H) (which it does not), the Commission has authority to approve Rider RRS provided it satisfies Section 4928.143(B)(2)(d).

Third, Section 4928.02(H) does not conflict with Rider RRS. The focus of Section 4928.02(H) is on anticompetitive subsidies flowing in either direction between noncompetitive and competitive retail electric services or products. As an example, the Commission should avoid an EDU transferring its distribution revenues to an unregulated affiliate in a manner that provides an anticompetitive subsidy to the affiliate's provision of competitive retail electric service. Rider RRS does not generate any distribution revenues – *i.e.*, revenues from distribution services or products – and is not a charge for distribution service. Any revenues Rider RRS does generate are not being used to subsidize retail electric generation service. Indeed, it is undisputed that the output from the Plants will not be used to provide generation to customers.[1357] Instead, the Companies are offering a stability rider to all of its customers, both shopping and non-shopping, that provides these customers insurance against long-term price increases and volatility. This is not an anti-competitive subsidy to the Companies' generation, but a benefit to the Companies' customers consistent with the policy under Section 4928.02(A) to ensure the availability to consumers of reasonably priced retail electric service.[1358] As the

[1357] Hearing Tr. Vol. I, p. 37-38 (Mikkelsen Cross).

[1358] *See AEP ESP3* Order, p. 26 (finding that AEP Ohio's PPA Rider was consistent with policy under R.C. 4928.02(A) to ensure the availability to consumers of reasonably priced retail electric service).

Commission determined in Duke Energy Ohio's most-recent ESP with respect to Duke Energy Ohio's analogous PSR rider:

> In response to the arguments raised by various intervenors that the PSR would violate R.C. 4928.02(H), which requires the Commission to ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies, we find that, contrary to intervenors' claims, the rider would not permit the recovery of generation-related costs through distribution or transmission rates. As discussed above, the PSR, whether a charge or a credit, would be considered a generation rate.[1359]

For the same reason, NOPEC's reliance[1360] on the *Sporn* case[1361] is unfounded, because AEP in that case "sought approval of a plant closure cost recovery rider, which the Company specifically classified as a non-bypassable distribution, not generation, rider that would have collected the generation-related costs associated with the closure of Sporn Unit 5."[1362] The Commission decided in the *Sporn* Case that AEP's recovery of its plant closure costs was not authorized by any section in Section 4928.143(B)(2).[1363] In contrast, Rider RRS is authorized by two separate sections in Section 4928.143(B)(2). The Commission also observed that AEP's request would be contrary to the state policy in Section 4928.02(H) because "such a charge would effectively allow the Company to recover competitive, generation-related costs through its noncompetitive, distribution rates."[1364] The Commission's decision was not based simply on the fact that the charge was nonbypassable, as represented by NOPEC.[1365] In contrast to the *Sporn*

[1359] *Duke ESP* 4 Order , p. 48 (April 2, 2015).

[1360] NOPEC Brief, pp. 47-48.

[1361] *In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider*, Case No. 10-1454-EL-RDR, Finding and Order (Jan. 11, 2012) ("*Sporn* Case").

[1362] *AEP ESP3* Order, p. 26.

[1363] *Sporn* Case Finding and Order, p. 18.

[1364] *Id.*. p. 19.

[1365] NOPEC Brief, pp. 47-48.

Case, the Commission found in its *AEP ESP3* Order, "the PPA rider, whether charge or credit, would be considered a generation rate."[1366]

Thus, Section 4928.02(H) is not a bar to approval of Rider RRS.

D. Rider RRS Does Not Conflict With Section 4928.03 Or With Ohio's Transition To Market-Based Generation Service Under S.B. 3.

Rider RRS does not violate Section 4928.03 as claimed by EPSA/P3 and Exelon.[1367] Section 4928.03 defines competitive retail electric services. While Rider RRS is a generation-related charge, it is not competitive retail electric generation service. Customers are not paying for generation. Indeed, witnesses sponsored by EPSA/P3 and Exelon admitted as much.[1368] Instead, Rider RRS is a retail stability charge that provides all customers insurance against the risks of competitive retail electric generation service. Thus, Section 4928.03 has no relevance here.

Likewise, Rider RRS does not violate the pro-market principles of S.B. 3 as claimed by OCC/NOAC, CMSD and P4S.[1369] OCC/NOPEC witness Ken Rose's opinions regarding S.B.3 reflect his experience during the late 1990s when he was an employee of the legislative service commission.[1370] His testimony essentially ignored all legislative events since then, including S.B. 221's authorization of ESPs in 2008 through Section 4928.143.[1371] He claimed to be unaware at the time he drafted his testimony here that Section 4928.143(B)(2)(c) authorizes a cost-based, nonbypassable charge to pay for new generation.[1372] He also claimed to be unaware

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[1366] *AEP ESP3* Order, p. 26.

[1367] EPSA/P3 Brief, p. 18; Exelon Brief, pp. 20-21.

[1368] Hearing Tr. XXVI, p. 5202 (Campbell Cross); Hearing Tr. XXVII, p. 5620 (Kalt Cross).

[1369] OCC/NOAC Brief, pp. 102-06; CMSD Brief, pp. 28-29; P4S Brief, pp. 3-5.

[1370] Rose Direct, p. 12; Hearing Tr. Vol. XXVI, p. 5375 (K. Rose Cross).

[1371] *See* Hearing Tr. Vol. XXVI, pp. 5380-81 (K. Rose Cross).

[1372] Hearing Tr. Vol. XXVI, p. 5383 (K. Rose Cross).

at the time he filed his testimony that Section 4928.143(B)(2)(f) and Section 4928.144 authorize an EDU to include a nonbypassable charge in an ESP to recover deferral of SSO price increases.[1373] Most importantly, Dr. Ken Rose's testimony ignores that Section 4928.143(B)(2)(d) authorizes a nonbypassable stability charge and that Section 4928.143(B)(2)(i) authorizes economic and job retention programs in an ESP.[1374]

Incredibly, Dr. Ken Rose failed to discuss in his testimony the applicability of Section 4928.143(B)(2) despite knowing that S.B. 221 was a specific response to the spikes in natural gas and wholesale energy prices in the mid-2000s.[1375] Energy prices at the time had increased from roughly $30/MWh to $60/MWh.[1376] As a result, the S.B. 3 market-based approach Dr. Ken Rose describes in his testimony was modified by S.B. 221 and its ESP concept, specifically to provide retail customers protection against the price spikes seen in the mid-2000s. S.B. 221 repealed the provision in then-Section 4928.14 requiring market-based SSO rates and substituted in its place the choice for a utility to implement an ESP or an MRO. His S.B. 3 world did not have nonbypassable riders for new generation, charges stabilizing or providing certainty regarding retail electric service, or economic development and job retention programs. His S.B. 3 world did not have single-issue ratemaking for distribution service.

The real world in which the Commission is reviewing the Companies' Stipulated ESP IV has a statute authorizing all these things and more. S.B. 3 proposed a transition to full market-based pricing for retail electric generation service; S.B. 221 realized the risk involved and instead emphasized rate stability. Ohio's current regulatory scheme is a quasi-market approach that

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[1373] Hearing Tr. Vol. XXVI, pp. 5383-84 (K. Rose Cross).

[1374] *See* Hearing Tr. Vol. XXVI, p. 5384 (K. Rose Cross).

[1375] *See* Hearing Tr. Vol. XXVI, p. 5382 (K. Rose Cross). *See also* Hearing Tr. Vol. IV, p. 704 (Company witness Strah describing price volatility in mid-2000s and rate stabilization plans for Ohio customers who otherwise would have seen retail generation price increases of roughly 25%).

[1376] Hearing Tr. Vol. XXVI, p. 5382 (K. Rose Cross).

attempts to provide retail customers the benefits of competitive markets while protecting them against market risks. Under Ohio's current regulatory scheme, hedges that protect retail customers against the risk of price increases are expressly authorized and encouraged.[1377] Thus, the fondness of OCC/NOAC, CMSD and P4S for a statutory scheme that the General Assembly rejected more than seven years ago should have no bearing on the Commission's decision in this proceeding.

E. Rider RRS Does Not Violate Section 4905.22.

The Commission can easily dispose of Stipulated ESP IV's opponents' reliance upon the "just and reasonable" language in Section 4905.22 as a claimed bar to Rider RRS.[1378] Section 4905.22 does not apply to retail stability charges authorized under Section 4928.143(B)(2)(d). A retail stability charge may be included in an ESP "notwithstanding any other provision of Title XLIX of the Revised Code," including Section 4905.22.[1379] Plus, a charge that protects retail customers against market risk and is projected to provide hundreds of millions of dollars of credits to customers is not by any means unjust or unreasonable. As such, Section 4905.22 does not apply.

[1377] OCC/NOAC's reliance on Ms. Vespoli's legislative committee testimony regarding subsidies is misplaced, given that a hedge is not a subsidy. *See* OCC/NOAC Brief, pp. 104, 106. Ms. Vespoli was discussing government-mandated purchases from Non-Utility Generators or NUGs. The Companies are not aware of any NUG that has agreed to flow through all its profits to retail customers for the purpose of stabilizing or providing certainty regarding retail electric service. In any event, the discussion of Ms. Vespoli's testimony in OCC/NOAC's brief is the subject of a motion to strike, filed concurrently with this Reply Brief.

[1378] EPSA/P3 Brief, p. 19; Exelon Brief, pp. 21-22.

[1379] R.C. 4928.143(B). For the same reason, paying OPAE a 5% administrative fee for services provided in managing the Community Connections program does not violate R.C. 4905.22. *See* EPSA/P3 Brief, p. 43; Exelon Brief, p. 69. Plus, no party has shown that a 5% administrative fee is unjust or unreasonable.

F. Rider RRS Does Not Violate Section 4928.38.

Rider RRS does not recover transition costs as alleged by OCC/NOAC and P4S.[1380] Each EDU had an opportunity, pursuant to a transition plan approved under Section 4928.33, to recover transition costs through transition revenues beginning on the starting date of competitive retail electric service in 2001.[1381] These costs could only be determined by the Commission upon the filing by an EDU of an application under Section 4928.31.[1382] The Companies are not attempting to recover pre-2001 generation costs through Rider RRS and are not asking the Commission to return to the year 2000 and award it transition revenues. OCC/NOPEC witness Ken Rose knows this: he admitted that none of the stranded costs that existed in 2001 are on the books today.[1383] Instead, the Companies are attempting to provide retail price stability to their customers. Thus, Rider RRS does not violate Section 4928.38.

Indeed, the Commission previously rejected this argument in earlier AEP and DP&L proceedings.[1384] As the Commission found then and as is equally true here, the Companies are not attempting to recover transition costs through its 1999 electric transition plan. The Companies are proposing ESP components authorized by Section 4928.143(B)(2). According to Section 4928.143(B), those components may be included in an ESP "notwithstanding any other provision of Title XLIX of the Revised Code." Section 4928.38 has no relevance here.

[1380] OCC/NOAC Brief, pp. 107-09; P4S Brief, pp. 13-14.

[1381] R.C. 4928.38.

[1382] R.C. 4928.39.

[1383] Hearing Tr. Vol. XXVI, p. 5391 (K. Rose Cross).

[1384] Hearing Tr. Vol. XXVI, p. 5402 (K. Rose Cross). *See AEP ESP*3 Order, p. 26 (PPA rider is a rate stability charge authorized by R.C. 4928.143(B)(2)(d), not a transition charge); Case No. 11-346-EL-SSO, Opinion and Order, p. 32 (Aug. 8, 2012); Case No. 12-426-EL-SSO, Opinion and Order, p. 22 (Sept. 4, 2013).

G. Rider RRS Does Not Violate Section 4928.20(K).

NOPEC's extreme view of Section 4928.20(K) distorts the meaning and plain language of the statute, and should be rejected.[1385] At a basic level, NOPEC contorts the words in the statute so as to expressly ignore the plain language. The statute imposes no obligation on the Companies to do anything with regard to large scale governmental aggregation; the obligation is on the Commission to promulgate rules and to *consider* the effect on large-scale governmental aggregation of any nonbypassable generation charges.[1386] The statute does not mandate that the Commission actually take any action once the effect has been considered.

Contrary to NOPEC's apparent wishes, Section 4928.20(K) does not insure customers of large scale governmental aggregation that no nonbypassable generation charge will be applied to them. In fact, the statute doesn't even mention *customers* of large scale governmental aggregations, only the aggregations themselves. But the only "harm" NOPEC suggests is the possibility, in NOPEC's view, that ultimately Rider RRS may be a charge to customers. That is not the type of "effect" the General Assembly had in mind. NOPEC certainly doesn't suggest that it is going to cease operations due to Rider RRS. And it doesn't suggest that it expects customers to opt out of its aggregation at a rate any faster than already occurs if Rider RRS is approved.

To be sure, nonbypassable generation charges have been applied to customers who take retail generation service as part of a large scale governmental aggregation program and the Commission found that riders such as Rider RRS are beneficial to customers by acting to

[1385] NOPEC Brief, p. 26.

[1386] R.C. 4928.20(K).

stabilize or provide certainty regarding retail electric service.[1387] Certainly nothing in statute prohibits governmental aggregation customers from paying nonbypassable generation-related charges, and the fact that, hypothetically, governmental aggregation customers are required to pay a nonbypassable generation-related charge does not make the underlying rider unlawful.

NOPEC also criticizes the Companies for not adequately assessing the impact on governmental aggregation.[1388] But, again, the Companies have no obligation to "assess the effect of nonbypassable generation on large scale governmental aggregation" arising from the statute. Thus, any allegation made by NOPEC regarding what assessment the Companies did or didn't undertake is meaningless.

NOPEC then states: "The legislature clearly understood as much and intended more by creating this special statutory provision."[1389] Unfortunately, NOPEC provides no basis for its bald conclusion that the legislature "intended more." Therefore, its conclusion is simply conjecture.

NOPEC again overstates what the statute says when it states: "including protecting large-scale governmental aggregation from an ESP's interference with the generation rates

[1387] *AEP ESP3* Order, p. 21. *See also Duke ESP4* Order, p. 44 ("The PSR…is intended to mitigate, by design, the effects of market volatility, providing customers with more stable pricing and a measure of protection against substantial increases in market prices."). Similarly, in AEP Ohio's second ESP proceeding, the Commission approved AEP Ohio's proposed nonbypassable Retail Stability Rider because it "promotes stable retail electric service prices and ensures customer certainty regarding retail electric service." Case No. 11-346-EL-SSO, Opinion and Order, p. 31 (Aug. 8, 2012). As the Commission noted, "an ESP may include terms, conditions, or charges relating to limitations on customer shopping for retail electric generation that would have the effect of stabilizing retail electric service or provide certainty regarding retail electric service." Case No. 11-346-EL-SSO, Opinion and Order, p. 31 (Aug. 8, 2012). Notably, the phrase "retail electric service" includes service provided by CRES providers. Case No. 11-346-EL-SSO, Opinion and Order, p. 31 (Aug. 8, 2012); *See also* Hearing Tr. Vol. XXVI, p. 5381 (K. Rose Cross) (agreeing that R.C. 4928.143(B)(2)(d) allows the Commission to award a stability charge to stabilize customer rates).

[1388] NOPEC Brief, pp. 26-27.

[1389] NOPEC Brief, p. 27.

agreed upon between the governmental aggregator and its chosen supplier."[1390] This language is nowhere to be found in the statute, and NOPEC provides no basis for it.

NOPEC does not understand what the Signatory Parties are proposing with Rider RRS, or, for that matter, how a hedge works. As noted, NOPEC's contract with FES is for a "percent off" product. The Companies' price to compare changes on a periodic basis making the pricing under NOPEC's contract with FES subject to price volatility. More specifically, when market prices for generation increases, the price for customers participating in NOPEC's governmental aggregation program will also increase. As wholesale capacity and energy prices increase, those increases will be reflected in wholesale winning bid prices from the Companies' competitive bid process, which will then be passed through to retail customers through the Companies' SSO price, and thereby will also have the effect of increasing the Companies' price-to-compare. It is the price-to-compare against which NOPEC's discount is calculated.

NOPEC's claim that its customers don't need a hedge thus is plainly wrong. Given that the prices they pay are variable and market-derived, those customers are little different from the Companies' SSO customers. The discount enjoyed by NOPEC's customers may save them on their bill, but it doesn't protect them from volatility or increases likely to come in the market. By acting counter to the direction of market prices, Rider RRS will provide a hedge that these customers don't have.

H. Rider RRS Does Not Raise Any Code Of Conduct Issues.

Exelon claims that the PPA Rider violates the corporate separation statute, Section 4928.17, because "the generation under Rider RRS will not be separated from the

[1390] *Id*.

Companies."[1391] Exelon puts such little weight on this argument that it does not even attempt to explain how it applies to the facts at hand. The Companies are required under Section 4928.17 to have a corporate separation plan approved by the Commission, and they do.[1392] There is no requirement that the Companies be "separated from" wholesale generation the Companies are using to provide a retail stability charge to their customers, as suggested by Exelon. There is a requirement that the Companies' provision of noncompetitive retail electric services be separate from an affiliate's provision of competitive retail electric services, and the Companies and FES have operated in compliance with this requirement for many years. Indeed, the Companies and FES adhered closely to this requirement and their Code of Conduct in negotiating the terms of the proposed transaction that will support the Economic Stability Program.[1393] As has always been the case, the Commission will have the opportunity to audit the Companies to ensure no affiliate abuse or Code of Conduct issues.

Exelon also fails to explain why Section 4928.17 would be applicable to a retail stability charge proposed under Section 4928.143. The prefatory language in Section 4928.17 expressly states that its provisions do not apply to ESPs or MROs.[1394] Conversely, since Rider RRS is

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[1391] Exelon Brief, pp. 18-19.

[1392] R.C. 4928.17(A). The Companies' corporate separation plan is publicly available as filed in Case No. 09-462-EL-UNC and approved in Case No. 10-388-EL-SSO. *See* Application, p. 19.

[1393] *See* Ruberto Direct, p. 4; Hearing Tr. Vol. XIII, pp. 2860-61 (Ruberto Cross). *See generally* Hearing Tr. Vol. III, pp. 507-08 (Mikkelsen Cross), where Company witness Mikkelsen describes the Companies' day-to-day compliance with O.A.C. 4901:1-37-04:

> The companies discharge their day-to-day responsibilities in all matters consistent with the provisions of 4901:1-37-04. We have training relative to these types of provisions, and we are all very, very mindful of these provisions. You know, looking through these, you know, we have -- we are located physically in separate offices, for example. We have separate accounting. There certainly was no suggestion in the term sheet of indebtedness that would have, for example, been incurred by an affiliate being assumed by the companies. So I guess my answer to that is the companies and the companies' employees conduct themselves daily in a manner that's consistent with the code of conduct in Ohio.

[1394] R.C. 4928.17(A) ("Except as otherwise provided in sections 4928.142 or 4928.143 or 4928.31 to 4928.40 of the Revised Code, . . .").

expressly authorized by Section 4928.143(B)(2)(d) and (i), Exelon's reading of the corporate separation statute would unreasonably limit the Companies' authority to implement an ESP. Consequently, Exelon's argument that Rider RRS violates the corporate separation statute is fundamentally flawed.

Exelon also suggests that the contract rights the Companies will have vis-à-vis FES as described in the Final Term Sheet will cause the Companies to be "involved with the generation."[1395] Exelon goes so far as to claim that the Companies' exercise of these contract rights will "subvert" the Commission's approval of the structural separation of the Companies' generation assets into FES.[1396] Again, Exelon fails to explain how these contract rights will violate Section 4928.17 or the Commission's prior orders. If Exelon's argument were to be taken seriously, then the Companies' contracts for SSO supply from FES and other wholesale providers would violate Section 4928.17 because the Companies would be "involved" in that generation also. Such an outcome would be directly contrary to Section 4928.141(A), which requires an electric distribution utility to provide a standard service offer "necessary to maintain essential electric service to consumers, including a firm supply of electric generation service." The fact is that Section 4928.17 does not prohibit the Companies from being "involved" in generation. It prohibits the Companies from providing competitive retail electric service. Because Rider RRS is not a competitive retail electric service, there is no issue involving Section 4928.17.

Similarly, would Exelon also argue that ESP provisions authorized under Divisions (B)(2)(b) and (B)(2)(c) of the ESP statute violate Section 4928.17? Under those provisions, an EDU would collect nonbypassable generation charges from its retail customers relating to newly-

[1395] Exelon Brief, p. 19.

[1396] Exelon Brief, p. 20.

built capacity owned by the EDU. That ownership would clearly make the EDU "involved" in generation, but it is expressly authorized by the General Assembly. In the same vein, nothing in the Revised Code or the Commission's rules prohibits affiliate transactions. To the contrary, Section 4928.143(B)(2)(a) explicitly permits EDUs to recover, in an ESP, the cost of purchased power acquired from an affiliate.

Exelon has not established any issue with or violation of the Companies' approved corporate separation plan. Thus, Rider RRS does not violate Section 4928.17.

I. Rider RRS Does Not Violate The Uniform Depositary Act.

CMSD claims that Rider RRS is contrary to state policy embodied in the Uniform Depository Act, R.C. Chapter 135.[1397] To be clear, CMSD does not claim that Rider RRS violates the Uniform Depository Act or limits the Commission's authority to approve Rider RRS.[1398] Instead, what CMSD believes is that it could not, as a political subdivision, directly invest in a derivative such as a financial hedge.[1399]

Of course, the Uniform Depository Act says nothing about the retail electric service charges paid by schools or other political subdivisions under an ESP. The Commission's review of the Companies' Stipulated ESP IV is governed by Section 4928.143, and nowhere in that statute did the General Assembly choose to exclude Ohio's political subdivisions from the benefits of ESPs, including retail stability charges and economic development programs. Thus, CMSD's reference to the Uniform Depository Act can be ignored.

[1397] CMSD Brief, pp. 30-33.

[1398] CMSD Brief, p. 31.

[1399] *Id.*

J. Rider RRS Does Not Run Afoul Of Federal Law.

1. Federal law does not preempt the Commission's authority to approve Rider RRS.

Several intervenors, including the IMM, OCC/NOAC, Sierra Club, CMSD and NOPEC, argue that federal law preempts Rider RRS and that the Commission therefore lacks the authority to act on this application.[1400] Sierra Club and NOPEC argue that Rider RRS "functionally sets" the wholesale rate that FES will receive for its sales and that Rider RRS therefore will supplant the wholesale rate generated by PJM's auction.[1401] OCC/NOAC similarly contend that Rider RRS is preempted because the underlying proposed transaction will "fix the amount [FES] will receive[] for capacity, energy, and ancillary services wholesaled [*sic*] on the PJM markets."[1402] Comparing Rider RRS to the state-initiated programs recently struck down in New Jersey and Maryland, OCC/NOAC also contend that the Commission's approval of Rider RRS would disrupt the efficient price signals of PJM's markets.[1403] Sierra Club similarly argues that Rider RRS "intrudes upon FERC's and PJM's regulation of wholesale markets" and is therefore preempted.[1404] These arguments are misguided for several reasons.

As an initial matter, Rider RRS – not the underlying proposed transaction – is what is before the Commission in this proceeding. Approval of Rider RRS does not involve any wholesale rates, terms, or conditions, let alone constitute approval of them. Rather, Rider RRS involves only the retail rate treatment of wholesale costs incurred under the proposed transaction,

[1400] OCC/NOAC Brief, p. 12-18; NOPEC Brief, pp. 11-18, Sierra Club Brief, pp. 121-25; CMSD Brief, pp. 18-26; IMM Brief, p. 5.

[1401] Sierra Club Brief, p. 122; NOPEC Brief, p. 15.

[1402] OCC/NOAC Brief, pp. 16-17.

[1403] *Id.*, pp. 17-18.

[1404] Sierra Club Brief, p. 123.

a retail regulatory matter over which this Commission has clear jurisdiction.[1405] Accordingly, the Commission's approval of Rider RRS would not run afoul of FERC's exclusive Federal Power Act authority to establish just and reasonable wholesale rates.

In addition, contrary to the assertions of Rider RRS' opponents, Rider RRS is not analogous to the state programs struck down in *Nazarian* and *Solomon*. In *Nazarian* and *Solomon*, the cornerstone of the state programs at issue was a state-run auction to procure capacity, which required distribution utilities to sign a wholesale contract with the winning bidder at a set price and amount of capacity for a specific duration. The state programs also required that the winning bidder clear in the PJM capacity markets for the first three years.

This Commission, on the other hand, is not being asked to conduct a state-run auction for capacity or to require utilities to sign a wholesale contract with the winning bidder at a set price, amount and duration. Nor is the Commission being asked to require that offers clear the PJM markets. As noted above, Rider RRS only addresses the retail rate treatment of FERC jurisdictional wholesale costs. Thus, Rider RRS, in contrast to the Maryland and New Jersey programs, falls squarely within the Commission's authority to set retail rates. Indeed, establishing retail rate treatment for wholesale costs, as Rider RRS does, is well within Ohio's long-established plenary authority to regulate retail sales of electric energy.[1406] As the United States Supreme Court recently articulated, "States continue to make or approve all retail rates, and in doing so may insulate them from price fluctuations in the wholesale market."[1407] That is

[1405] *See, e.g., Market-Based Rates For Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 72 FR 39,90 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252 at P 527 & n.542, *on reh'g*, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268 at PP 415-416 & nn. 596-597 (citing cases).

[1406] 16 U.S.C. § 824(b)(1).

[1407] *FERC v. EPSA*, No. 14-840, slip. op. at 21 (Jan. 25, 2016).

precisely what Rider RRS would do here. Rider RRS provides ratepayers with a long-term retail rate stability mechanism that hedges the uncertainty inherent in the wholesale market.[1408]

The broad and sweeping preemption arguments offered by the opponents of Rider RRS, if accepted, are inconsistent with matters explicitly left to the states by Congress, including retail rate stability, resource adequacy and regulation over generation resources used to serve retail customers. States retain wide latitude to regulate these matters.[1409] Without violating the Federal Power Act, state commissions may require EDUs to purchase particular quantities of energy or capacity from particular kinds of generation resources.[1410] Indeed, a state can favor a particular generator or type of generation without being preempted by the Federal Power Act.[1411] And state commissions can regulate EDU purchases to support fuel diversity or reliability.[1412] The Third Circuit in *Solomon* clarified that "When a state regulates within its sphere of authority, the regulation's incidental effect on interstate commerce does not render the regulation invalid. . . . The states may select the type of generation to be built—wind or solar, gas or coal—and where to build the facility. Or states may elect to build no electric generation facilities at all."[1413] Nothing prohibits Ohio from selecting a desired generation resource mix for the state of

[1408] Companies' Initial Brief, p. 22.

[1409] *See, e.g., Nazarian*, 753 F.3d at 479-80 (explaining that a holding that "every state regulation that incidentally affects federal markets is preempted . . . would thoroughly undermine precisely the division of the regulatory field that Congress went to so much trouble to establish . . . , and would render Congress' specific grant of power to the States . . . virtually meaningless" (citation omitted).

[1410] Hearing Tr. Vol. XXI, p. 4170 (Roberto Cross).

[1411] *See, e.g., Allco Fin. Ltd. v. Klee*, 2014 U.S. Dist. LEXIS 170674, at *25 (D. Conn., Dec. 10, 2014), *aff'd* on other grounds, 805 F.3d 89 (2nd Cir. 2015), *citing Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d 393, 417 (2d Cir. 2013) ("'[S]tates have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction and"may, for example, order utilities to build renewable generators themselves, or . . . order utilities to purchase renewable generation.") (citations omitted).

[1412] Hearing Tr. Vol. XXI, pp. 4170-71 (Roberto Cross).

[1413] *Solomon*, 766 F.3d at 255.

Ohio.[1414] As the court in *Nazarian* emphasized, such state actions are not automatically preempted simply because they could impact the wholesale markets, as "not every state statute that has some indirect effect on wholesale rates is preempted."[1415]

2. Approval of Rider RRS would not violate the dormant Commerce Clause.

NOPEC asserts that the Commission's approval of Rider RRS would violate the dormant commerce clause, claiming that Rider RRS has "both a discriminatory purpose and discriminatory effect" against out of state generators.[1416] Cases applying the dormant Commerce Clause to find state actions invalid mainly address so-called "economic protectionism" – "that is, regulatory measures *designed* to benefit in-state economic interests *by burdening out-of-state competitors*."[1417] As discussed below, NOPEC's conclusory assertions should be rejected because they fail to demonstrate that either: (1) Stipulated ESP IV and Rider RRS are designed for the purpose of engaging in prohibited "economic protectionism" with respect to the Ohio-based plants included under Rider RRS; or (2) Stipulated ESP IV and Rider RRS impose any burdens on the ability of out-of-state generators to compete in the interstate wholesale markets to serve Ohio loads. For these reasons, a Commission order approving Stipulated ESP IV and Rider RRS would not violate the dormant Commerce Clause.

[1414] Hearing Tr. Vol. XXI, pp. 4172-73 (Roberto Cross). *See also Conn. Dep't Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (explaining the expansive scope of state discretion to select preferred sources of generation); *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 97-98 (3d Cir. 2014) (adopting the D.C. Circuit's holding).

[1415] *Nazarian*, 753 F.3d at 478. The Third Circuit in Solomon has even explained that "New Jersey may also directly subsidize generators so long as the subsidies do not essentially set wholesale prices." *Solomon*, 766 F.3d at n. 4. The Fourth Circuit explained that "We need not express an opinion on other state efforts to encourage new generation, such as direct subsidies or tax rebates, that may or may not differ in important ways from the Maryland initiative. It goes without saying that not every state statute that has some indirect effect on wholesale rates is preempted, *Schneidewind*, 485 U.S. at 308, 108 S.Ct. 1145, (internal quotes omitted), for there can be little if any regulation of production that might not have at least an incremental effect on the costs of purchasers in some market, Nw. Cent. Pipeline Corp., 489 U.S. at 514, 109 S.Ct. 1262." *Nazarian*, 753 F.3d at 478.

[1416] NOPEC Brief, pp. 15-17.

[1417] *New Energy Co. of Ind. v. Limbach*, 486 U.S. 269, 273-274 (1988) (emphasis added).

In an attempt to support its claim that Rider RRS runs afoul of the dormant Commerce Clause, NOPEC relies on statements in the Application recognizing the reality that the Sammis and Davis-Besse plants generate jobs and tax revenue in the regions where they are located and avoid the need to deliver power to retail customers from longer distances.[1418] In doing so, NOPEC ignores the overwhelming record evidence of the numerous benefits that Rider RRS will provide to retail customers that have nothing to do with their in-state location or any direct economic benefits they may provide. As the Companies fully explained in their Initial Brief, the unique physical and operational attributes of the Plants – especially their coal and nuclear fuel sources, significant onsite fuel storage, and ability to operate continuously in all conditions – provide significant benefits to the Companies' customers.[1419] For example, the Plants contribute significantly to fuel and resource diversity, which enhances reliability and retail rate stability as the PJM region becomes increasingly reliant on natural gas to fuel power generation.[1420] In addition, Rider RRS helps ensure that retail customers will avoid significant transmission costs that would be incurred to address reliability issues resulting from premature closure of the Plants.[1421] Further, the Plants are already well-positioned to comply with current and future environmental requirements, providing both environmental and cost advantages.[1422] All of these proven benefits – which are well within the Commission's authority to consider[1423] – provide a

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[1418] NOPEC Brief, pp. 16-17.

[1419] Companies' Initial Brief, pp. 24-27.

[1420] *Id.*

[1421] *Id.*, pp. 27-29.

[1422] *Id.*, p. 30.

[1423] 16 U.S.C. §§ 824(b)(1); *see, e.g.*, *FERC v. EPSA*, 136 S. Ct. 760, 777 (2016) (noting that state commissions often insulate retail customers from volatility in wholesale prices by insisting that utilities set stable retail rates); *Conn. Dep't Pub. Util. Control*, 569 F.3d at 481 (states retain wide discretion in matters related to generating resources); *N.J. Bd. of Pub. Utils.*, 744 F.3d at 97-98 (same); *PPL Energyplus, LLC v. Hanna*, 977 F. Supp. 2d 372, 411-12 (D.N.J. 2013) (holding that state action to encourage power plants in areas where "reliability concerns are in flux" was reasonable and did not violate dormant Commerce Clause).

sufficient basis for Commission approval of Rider RRS, regardless of the in-state location of most of the Plants.[1424]

Moreover, under the dormant Commerce Clause, "'[d]iscrimination' simply means differential treatment of in-state and out-of-state economic interests that benefits the former *and burdens the latter*."[1425] NOPEC fails to show that a Commission order approving Stipulated ESP IV including Rider RRS would burden "out-of-state economic interests" by erecting barriers to the ability of out-of-state generators to compete in the interstate wholesale markets to serve Ohio loads. In fact, NOPEC identifies no specific burden that Stipulated ESP IV or Rider RRS places on out-of-state generators, beyond NOPEC's largely unexplained assertion that "Rider RRS can only have the effect of encouraging output from the PPA Units and thereby displacing other, efficient suppliers' output in the wholesale power and capacity markets."[1426] This assertion ignores the fact that, under the structure of Stipulated ESP IV and Rider RRS, multiple in-state and out-of-state generators will continue to compete without restriction to serve Ohio loads.[1427] The Companies will continue to use laddered and staggered SSO auctions to procure generation for their non-shopping retail customers from multiple resources within and outside Ohio. In addition, the Plants will continue to participate in the PJM energy, capacity and ancillary services markets under PJM's FERC-approved market rules, and their output will be determined by the PJM market and dispatch processes.[1428] This structure does not burden interstate commerce in any way.

[1424] It should be noted that one of the Plants included within the portfolio of resources covered by Rider RRS, Clifty Creek, is located in Indiana, not Ohio. Additionally, while Sammis is physically located in Ohio, it sits in a multi-state region and thus has impacts well beyond the borders of Ohio.

[1425] *Oregon Waste Sys., Inc. v. Dep't of Envtl. Quality*, 511 U.S. 93, 99 (1994)

[1426] NOPEC Brief, p. 17.

[1427] *Cf. PPL EnergyPlus, LLC v. Nazarian*, 974 F.Supp.2d 790, 851-52 (D. Md. 2013).

[1428] *Id.* at 852-53.

3. There is no justification for delaying this proceeding until FERC rules on the EPSA Complaint.

OCC/NOAC argue, without citation to any authority or analysis, that the Commission should delay issuing an order on Stipulated ESP IV until FERC rules on the EPSA Complaint.[1429] Instead of offering a plausible explanation for why a further delay in the resolution of this proceeding is warranted, OCC/NOAC simply repeat the arguments raised in the EPSA Complaint (and OCC/NOAC's supporting comments, filed with FERC the same day) regarding the Companies and FES's waiver from FERC's affiliate sales restrictions.

The Application here was filed with the Commission on August 4, 2014. Since that time a voluminous record has been assembled regarding all aspects of the proposal, and a Third Supplemental Stipulation has been reached with numerous parties. The Commission has all of the information it needs to render a decision now, and should not delay its decision any further based on OCC/NOAC's unsupported theory that the Commission should wait for FERC action on EPSA's complaint.

Conversely, the EPSA complaint raises a narrow issue regarding the application of federal regulations governing wholesale transactions between affiliates (assuming the Complaint is even properly perfected in the first place). The EPSA complaint thus is not relevant to the determinations the Commission must make here under Ohio law regarding whether Stipulated ESP IV and Rider RRS should be approved.

[1429] OCC/NOAC Brief, pp. 24-25.

4. *Edgar* standards.

Exelon claims that the PPA should be reviewed under FERC's *Edgar* standard.[1430] It is up to FERC and not the Commission to make determinations about the existing affiliate waiver and whether the *Edgar* standard applies. These issues are beyond the scope of this proceeding.

K. Rider ELR Does Not Conflict With Section 4928.6613.

ELPC is incorrect in suggesting that language in Section V.A.1.i.6. of the December 22, 2014 Stipulation is inconsistent with Section 4928.6613, which was enacted as part of S.B. 310 in 2014.[1431] At issue is language in Section 4928.6613 that bars accounts that have opted out of an EE/PDR portfolio plan under Section 4928.6611 from participating in, or directly benefiting from, "programs arising from electric distribution utility portfolio plans approved by the public utilities commission."[1432] In that Section of the Stipulation, the Signatory Parties state: "For purposes of clarification, ELR customers may opt out of the opportunity and ability to obtain direct benefits from the Companies' EE/PDR Portolio Plans as provided by S.B. 310."

Rider ELR customers may opt-out of the Companies' EE/PDR Portfolio Plans and continue to receive Rider ELR credits because those credits do not "arise from" the Companies' EE/PDR Portfolio Plans. To the contrary, those credits will be authorized components of, and will arise from, the Stipulated ESP IV. Indeed, they were created in the Companies' ESP I – as both an economic development program and an energy efficiency program under Section 4928.143(B)(2)(i) – and were continued as authorized ESP components in the Companies' ESP II and ESP III.[1433] The Rider ELR credits approved in ESP I pre-dated the Companies' first

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[1430] Exelon Brief, p. 22-23.

[1431] ELPC Brief, p. 58.

[1432] R.C. 4928.6613.

[1433] Case No. 08-935-EL-SSO, Opinion and Order, pp. 10, 17-18 (Mar. 25, 2009) (approving Rider ELR as proposed by the Companies and as modified by a stipulation); Case No. 10-388-EL-SSO, Opinion and Order, p. 45 (Aug. 25, EE/PDR Portfolio Plan by approximately two years and, thus, necessarily arose from ESP I.[1434] In ESP III, although OCC encouraged the Commission not to address Rider ELR in that proceeding, an environmental intervenor, Sierra Club, recognized that Rider ELR was authorized as an energy efficiency program under Section 4928.143(B)(2)(i).[1435] Because Rider ELR credits do not arise from the Companies' EE/PDR Portfolio Plan, the Stipulation does not authorize opt outs in violation of Section 4928.6613. Instead, the Stipulation simply makes clear that Rider ELR customers may opt-out while continuing to receive the benefits of Stipulated ESP IV.

L. The Rate Decoupling Section Of The Third Supplemental Stipulation Advances Ohio Policy.

OCC/NOAC object that Section V.F. of the Third Supplemental Stipulation – under which the Companies will file a case to transition residential base distribution rates to a straight fixed variable cost recovery mechanism – is a "vast" rate redesign that should not take place in the context of an ESP proceeding.[1436] OCC/NOAC's views likely are clouded by their misunderstanding that this section of the Third Supplemental Stipulation obligates the Companies, together with the Commission, to implement a specific straight fixed variable ("SFV") rate design starting January 1, 2019.[1437] Indeed, OCC/NOAC's Brief still misrepresents

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2010) ("The Commission notes that continuation of Riders ELR and OLR has been one objective of several parties in this proceeding since the filing of the *MRO Case*. The recommendation to continue Riders ELR and OLR was the result of good faith negotiations between those parties and the other signatory parties to the Combined Stipulation."); Case No. 12-1230-EL-SSO, Opinion and Order, pp. 37-38 (July 18, 2012).

[1434] The Commission approved the Companies' ESP I on March 25, 2009 in Case No. 08-935-EL-SSO, and approved the Companies' first EE/PDR Portfolio Plan on March 23, 2011 in Case No. 09-1947-EL-POR.

[1435] Case No. 12-1230-EL-SSO, Opinion and Order, pp. 35-36 (July 18, 2012).

[1436] OCC/NOAC Brief, pp. 160-63, 169-70.

[1437] Rubin Supp., pp. 3-5.

Section V.F. by stating that "FirstEnergy has agreed in the settlement to transition to a straight fixed variable ("SFV") rate design for residential customers."[1438] This is incorrect.

As was shown at hearing, OCC/NOAC's misunderstanding was based on OCC's witness's failure to review the actual Section V.F. in the Third Supplemental Stipulation prior to the morning of January 20, 2016.[1439] Every reference to Section V.F. of the Third Supplemental Stipulation in OCC witness Rubin's testimony was based on an incorrect version of the Third Supplemental Stipulation.[1440] What Section V.F. of the actual filed version of the Third Supplemental Stipulation requires is that the Companies make a filing with the Commission by April 3, 2017 proposing a transition to SFV rate design for their residential customers' base distribution rates.[1441] That filing will then be subject to the Commission's typical process in which all interested parties may address the merits of such a transition and the Commission then can decide what rate design is appropriate.[1442] Notably, OCC/NOPEC witness Kahal testified that it would be "very helpful" if the Commission confirms the Companies' position, as reflected in the language of the Third Supplemental Stipulation, that the Commission is not prejudging the merits of SFV rate design or SFV ratios by approving the Third Supplemental Stipulation.[1443] The Third Supplemental Stipulation does not "settle" this rate design issue as misrepresented by OCC/NOAC.

Although OCC/NOAC complain, based on ELPC witness Rábago's testimony, that the Third Supplemental Stipulation's decoupling filing commitment should not be included in this

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[1438] OCC/NOAC Brief, p. 169.

[1439] Hearing Tr. Vol. XXXIX, pp. 8260-62 (Rubin Cross).

[1440] Hearing Tr. Vol. XXXIX, pp. 8271-72 (Rubin Cross).

[1441] Mikkelsen Fifth Supp., p. 4.

[1442] Hearing Tr. Vol. XXXVI, pp. 7577, 7584 (Mikkelsen Cross).

[1443] Hearing Tr. Vol. XXXVIII, pp. 8236-37 (Kahal Cross).

proceeding,[1444] its complaint is based on the erroneous view that this proceeding is a PPA Rider proceeding, rather than an ESP proceeding. Under Section 4928.143(B)(2)(h), an ESP may include provisions "regarding the utility's distribution service, including . . . provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking." OCC's and ELPC's witnesses either were not familiar with this express statutory authorization,[1445] or freely admitted that the Companies' ESP could include provisions relating to distribution service.[1446] ELPC's witness was confused by first preparing testimony for AEP's much narrower PPA Rider proceeding and then using the same testimony to criticize including "non-core provisions" in the Companies' much broader ESP proceeding.[1447] ELPC's witness also readily admitted that he lacked sufficient understanding of it – having not reviewed any of the record – to offer an opinion on the Stipulated ESP IV, despite then offering an uninformed opinion on certain components of Stipulated ESP IV.[1448]

Importantly, criticisms of the merits of SFV rate design are irrelevant for purposes of reviewing the Third Supplemental Stipulation. As pointed out by an OCC witness, the Commission has encouraged all EDUs in Ohio to include an SFV rate design in their next base distribution rate cases.[1449] Yet, if Stipulated ESP IV is approved, the next base distribution rate case may not be filed until sometime in 2023.[1450] Thus, it is reasonable for the Companies and all other Stipulating Parties to recommend that this issue be considered in an ATA proceeding

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[1444] OCC/NOAC Brief, p. 161, relying on ELPC witness Rábago's testimony.

[1445] Hearing Tr. Vol. XXXIX, pp. 8265-69 (Rubin Cross); Hearing Tr. XXXVIII, p. 8173 (Rábago Cross).

[1446] Hearing Tr. Vol. XXXVIII, p. 8222 (Kahal Cross).

[1447] Hearing Tr. Vol. XXXVIII, pp. 8169-72 (Rabago Cross); Rábago Direct, p. 5.

[1448] Rábago Direct, p. 8; Hearing Tr. Vol. XXXVIII, p. 8175 (Rabago Cross).

[1449] Rubin Supp., p. 10.

[1450] *See* Third Supp. Stip., Section V.G.1. (base distribution rate freeze until June 1, 2024).

commencing in April 2017.[1451] This does not "predetermine" a non-core issue as suggested by ELPC witness Rábago;[1452] instead, it allows reasoned review in a separate proceeding of an issue deemed important by the Commission and other parties. Indeed, in Duke Energy Ohio's second ESP proceeding, Case No. 11-3549-EL-SSO *et al.*, the Commission approved a similar request by stipulating that a distribution revenue decoupling mechanism be addressed in a future proceeding, finding that it did not violate an important regulatory principle or practice.[1453] The same finding can be made here.

M. Rider DCR And GDR Are Not Improper Single-Issue Ratemaking.

OCC/NOAC and OMAEG argue that the Companies' collection of distribution costs through Rider DCR and Rider GDR violate important regulatory principles on the basis that they represent improper single-issue ratemaking.[1454] OMAEG in particular argues that the standard by which a cost recovery mechanism outside of a traditional base rate case should be judged as proper single-issue ratemaking is whether or not it recovers utility costs that are large, volatile, and outside the utility's control.[1455] OMAEG provides no legal support for this standard. Further, these restrictions are not included in the relevant statute, which specifically provides for provisions related to single-issue ratemaking.[1456] Notably, the Companies' have demonstrated that the purpose of Rider GDR is to recover potentially large costs that are outside of the Companies' control.[1457]

[1451] Mikkelsen Fifth Supp., p. 4; Third Supp. Stip., Section V.F.

[1452] Rábago Direct, pp. 17-18.

[1453] Case No. 11-3549-EL-SSO et al., Opinion and Order, p. 44 (Nov. 22, 2011).

[1454] OCC/NOAC Brief, p. 60; OMAEG Brief, p. 84.

[1455] OMAEG Brief, p. 84.

[1456] R.C. 4928.143(B)(2)(h).

[1457] Companies' Initial Brief, p. 89.

OCC/NOAC argue that approval of Rider DCR would violate the single-issue ratemaking provision of Section 4928.143(B)(2)(h) because it is not part of a "distribution infrastructure modernization" initiative. This is an incorrect and overly narrow reading of the statute by OCC witness Williams. OCC/NOAC cite no legal authority for its interpretation of the statute, which is unsurprising given that OCC/NOAC are simply wrong. The statute expressly permits single issue ratemaking as part of an ESP separate and apart from an infrastructure modernization plan.

The Commission, in approving Rider DCR, is required to review the Companies' reliability performance and ensure: (1) the alignment of the Companies' reliability performance and customers' expectation regarding reliability; and (2) the Companies are placing sufficient emphasis and resources to assure reliability on the Companies' systems. Company witness Mikkelsen testified in detail that the Companies fulfill both these conditions.[1458] Equally important is that Staff also reviewed the Companies' Rider DCR proposal and found that it met the requirements of Section 4928.143(B)(2)(h).[1459] The Commission has approved Rider DCR in the Companies' previous ESP II and ESP III cases without raising any concern with respect to single-issue ratemaking.[1460] It should do so again here.

N. Additional Changes To The Rider GCR Bypassability Threshold Are Unnecessary.

RESA contends that Rider GCR should be modified so that if the bypassability threshold is triggered (thereby making Rider GCR nonbypassable), then the Companies should file a request with the Commission. RESA would have the filing state why the threshold has been

[1458] *See* Mikkelsen Direct, pp. 9-11; *see* also Companies' Initial Brief, pp. 82-85.

[1459] Staff Ex. 4, pp. 6-10 (Nicodemus direct).

[1460] *See* the Commission's *Opinion and Order* in Case No. 10-388-EL-SSO; *see* also the Commission's *Opinion and Order* in Case No. 12-1230-EL-SSO.

triggered and include a plan to address the factors which are causing the deferral to rise.[1461] These additional steps are unnecessary for several reasons.

First, to date, the bypassability threshold has never been triggered in two consecutive quarters.[1462] RESA witness Bennett admitted as much on cross-examination.[1463] Second, RESA's Brief is relies on testimony that is based upon the Companies' original filing, which had the "bypassability threshold" at 5%.[1464] The 5% threshold relied upon by RESA is out of date. As RESA should know, one of the provisions included in the Stipulation and Recommendation filed on December 22, 2014 was that the threshold would be doubled from 5% to 10%.[1465] Therefore, even if RESA's concerns were valid at the 5% threshold level (which they were not), they are now wholly without merit given that Stipulated ESP IV has a revised Rider GCR bypassability threshold of 10%. Indeed, RESA witness Bennett admitted that increasing the threshold to 10% from 5% would make it even less likely that the threshold would ever be triggered.[1466] Third, Rider GCR is updated quarterly, and such updates would reveal if the bypassability threshold was exceeded such that Rider GCR would become bypassable. This information is already publicly available.

RESA also asserts there is no process to revert Rider GCR back to being bypassable.[1467] This reflects a lack of understanding of how the bypassability threshold is applied to Rider GCR with each quarterly update.[1468] Rider GCR would revert back to a bypassable charge as the

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[1461] RESA Brief, pp. 18-19.

[1462] Savage Direct, p. 7.

[1463] Hearing Tr. Vol. XXVI, p. 5354 (Bennett Cross).

[1464] RESA Brief, p. 19.

[1465] Companies' Initial Brief, pp. 79-80.

[1466] Hearing Tr. Vol. XXVI, p. 5354 (Bennett Cross).

[1467] RESA Brief, pp. 18-19.

[1468] Savage Direct, p. 6.

deferral balance at the Companies decreased and the bypassability threshold is not exceeded. Therefore, it is unnecessary to address this concern as the tariff because proposed rider already resolves it.

O. The Companies' Recovery Of Lost Distribution Revenues Tied To The Customer Action Program Does Not Violate Ohio Policy.

ELPC argues that the Commission should bar the Companies from seeking lost distribution revenue on the Companies' Customer Action Program ("CAP"), as authorized by Section V.E.3.d. of the Third Supplemental Stipulation.[1469] ELPC's position should be rejected. Being able to recover lost distribution revenues arising from savings from the CAP is an integral part of Stipulated ESP IV and supported by all of the Signatory Parties. Just as importantly, the CAP is an energy efficiency program authorized by Section 4928.662 contained in the Companies' Commission-approved EE/PDR Portfolio Plans.[1470] The CAP identifies kWh savings as a result of energy efficiency being undertaken by customers. Just like all other Commission-approved energy efficiency programs, these savings being achieved by customers will give rise to lost distribution revenue.[1471] In addition, similar to all other Commission-approved energy efficiency programs, savings arising from the CAP would also be subject to the same measurement and verification protocols before any savings, which would lead to lost distribution revenues, may be counted.[1472]

The Commission stated in its order in the Companies' most recent EE/PDR Portfolio Plan proceeding that the issue of lost distribution revenues related to the CAP would be decided

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[1469] ELPC Brief, p. 60.

[1470] *See In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Their Energy Efficiency and Peak Demand Reduction Program Plans for 2013 through 2015*, Case No. 12-2190-EL-POR *et al*., Finding and Order, pp. 8-9 (Nov. 20, 2014) ("2014 EE/PDR Order").

[1471] Hearing Tr. Vol. III, p. 541 (Mikkelsen Cross)

[1472] Hearing Tr. Vol. III, p. 559 (Mikkelsen Cross) in this proceeding.[1473] ELPC has not provided an adequate basis for the Commission to deny such recovery. There are at least three reasons why. First, the Commission decisions relied upon by ELPC pre-date the enactment of SB 310. SB 310 specifically authorized the CAP.[1474] Second, one Commission decision relied upon by ELPC – the June 30, 2010 Finding and Order in Case No. 09-1820-EL-ATA – related to the Companies' smart grid pilot program. That decision was limited to the facts presented in the smart grid proceedings and does not apply to this ESP proceeding. Third, the only other decision cited by ELPC was issued in the Companies' first EE/PDR Portfolio Plan proceeding, and the language misquoted by ELPC merely affirms that savings from the revised CFL program must be verified in order for the Companies to collect lost distribution revenues.[1475] The CAP is a Commission-approved energy efficiency program, and therefore meets the standard set out by the Commission related to the ability to recover lost distribution revenues.[1476]

Because the CAP is an approved energy efficiency program specifically authorized by SB 310, and ELPC has not presented any evidence as to why this energy efficiency program should be treated differently than other approved energy efficiency programs, lost distribution revenue recovery should be authorized for the CAP program.

[1473] 2014 EE/PDR Order, pp. 18-19.

[1474] R.C. 4928.662(A).

[1475] *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Their Energy Efficiency and Peak Demand Reduction Program Plans for 2010 through 2012 and Associated Cost Recovery Mechanism*, Case No. 09-1947-EL-POR *et al.*, Opinion and Order, p. 18 (Mar. 23, 2011) ("2011 EE/PDR Order"). ELPC's Brief substitutes "a utility's efficiency programs" for the actual language in the Opinion and Order, which says "the revised CFL program".

[1476] *See* 2011 EE/PDR Order, p. 21.

P. The Federal Advocacy Section Of The Third Supplemental Stipulation Does Not Violate Ohio Policy.

Exelon and EPSA/P3 suggest that a recommendation in the Third Supplemental Stipulation may violate Ohio policy by requiring the Commission to take action.[1477] The provision at issue is Section V.C.3., which states: "In the event that PJM has not obtained approval for a longer term capacity product to address State resource adequacy needs by September 1, 2017, the Commission will solicit comments from interested parties no later than October 30, 2017, addressing the State's long term resource adequacy needs." This is a recommendation from the Signatory Parties that the Commission take this action if PJM fails to act. The Commission certainly is within its powers to accept the recommendation if it believes that soliciting comments from interested parties would also be reasonable under the circumstances. The recommendation does not violate Ohio policy.

Q. The Companies' Proposed High Load Factor Time-of-Use Pilot Program Should Be Approved as Part Of Stipulated ESP IV.

Both RESA and Exelon assert that the High Load Factor Time-of-Use Pilot Program is unduly discriminatory and unjust.[1478] RESA mischaracterizes the Companies' testimony in its attempt to discount the importance of a "homogenous participant pool" by alleging that the Companies stated that a homogenous pool "was not necessary for the pilot results."[1479] This allegation is untrue. Ms. Mikkelsen explained that the eligibility requirements were necessary to effectively evaluate the Experimental Program, and to do so a "homogenous participant pool" is necessary.[1480] The actual Company testimony, which RESA mischaracterized, was:

[1477] Exelon Brief, p. 69; EPSA/P3 Brief, p. 43.

[1478] RESA Brief, p. 51-53; Exelon Brief pp. 69-70.

[1479] RESA Brief, p. 52.

[1480] Hearing Tr. Vol. II, pp. 463-467 (Mikkelsen Cross); Mikkelsen Rebuttal, p. 17; Hearing Tr. Vol. II, pp. 290-291 (Mikkelsen Cross).

> While it does not matter to the company in terms of its cost to serve the company, it is important or considered important to the company to have as homogenous a group of pilot participants as possible in this pilot so the companies are better able to compare and evaluate customers that participate. And so that serves to contribute to the overall homogenous nature of the pilot participants.[1481]

RESA has expressed further concern regarding the ability of a customer "to remain on the pilot even if their qualifications do not remain" and stated that as a result of this "loophole", for which RESA claims the Companies provided no explanation, "the design and success of the pilot are questionable."[1482] RESA's concern is revealing of its failure to recognize the purpose of the experimental program. The purpose of the HLF-TOU program is to "test customers' willingness to modify their peak load shape as it relates to their generation service"[1483] or their ability to do so during on-peak periods in response to a capacity-price signal, and, by doing so, their improved load shape will reduce key charges overall.[1484]

The testimony that RESA relies upon for its "loophole" actually supports the opposite view. In that testimony, Ms. Mikkelsen explained that the purpose of the program was to incentivize participants "to improve their consumption by managing their on-peak load" and *not* to "reward them by disqualifying them for that rate." Thus, it is the intent of this program for participating customers to stay on the program. RESA's and Exelon's complaints regarding the HLF-TOU program are unfounded, and the Commission should include the program as part of its approval of Stipulated ESP IV.

[1481] Hearing Tr. Vol. II, p. 463 (Mikkelsen Cross).

[1482] RESA Brief, p. 52.

[1483] Hearing Tr. Vol. II, p. 286 (Mikkelsen cross).

[1484] Hearing Tr. Vol. XXXIV, pp. 7097-7098 (Mikkelsen Cross).

R. The Transition Provision Of The Third Supplemental Stipulation – Section V.K. – Does Not Violate An Important Regulatory Principle Or Practice.

OCC/NOAC and CMSD ask that Section V.K. of the Third Supplemental Stipulation be modified to permit termination of Riders RRS and DCR if Stipulated ESP IV fails the fourth test under Section 4928.143(E).[1485] However, the termination and transition process in Section V.K. is consistent with statutory requirements. Importantly, the Commission's approval of the transition provision is a necessary precondition to the Companies agreeing to extend the term of Stipulated ESP IV from three years to eight years.[1486]

Section 4928.143(E) provides for a two-part test of Stipulated ESP IV in its fourth year: (1) a forward-looking ESP v. MRO test, and (2) a forward-looking SEET.[1487] If Stipulated ESP IV fails the ESP v. MRO test or the Companies fail the prospective SEET, the Commission may,

[1485] CMSD Brief, p. 39; OCC/NOAC Brief, p. 52.

[1486] *See* Third Supp. Stip., Section V.A.1.

[1487] R.C. 4928.143(E) provides in full:

> If an electric security plan approved under division (C) of this section, except one withdrawn by the utility as authorized under that division, has a term, exclusive of phase-ins or deferrals, that exceeds three years from the effective date of the plan, the commission shall test the plan in the fourth year, and if applicable, every fourth year thereafter, to determine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. The commission shall also determine the prospective effect of the electric security plan to determine if that effect is substantially likely to provide the electric distribution utility with a return on common equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. . . . If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that will face comparable business and financial risk, with such adjustments for capital structure as may be appropriate, during the balance of the plan, the commission may terminate the electric security plan, but not until it shall have provided interested parties with notice and an opportunity to be heard. The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative. In the event of an electric security plan's termination pursuant to this division, the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan.

but is not required to, terminate Stipulated ESP IV and "impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative."[1488]

OCC/NOAC's and CMSD's arguments are based on a flawed assumption, *i.e.*, that Stipulated ESP IV will fail the ESP v. MRO test in its fourth year. NOPEC and CMSD offer nothing to support this assumption, much less that such failure would be based on costs attributed to Riders RRS and DCR. OCC/NOAC rely on OCC/NOPEC witness Kahal's testimony regarding his analysis of the ESP v. MRO test.[1489] But Mr. Kahal's analysis deserves no weight because, among other reasons, he relies on OCC/NOPEC witness Wilson's "numbers" that are wholly unreliable and discredited.[1490]

Those intervenors' arguments also erroneously assume that, even if Stipulated ESP IV would fail the ESP v. MRO test quantitatively, that would be the end of the ESP. The fourth-year test, like the ESP v. MRO test under Section 4928.143(C)(1), considers both the quantitative and qualitative attributes of the ESP.[1491] CMSD and OCC/NOAC ignore the future benefits that the continuation of Rider RRS and Rider DCR would provide customers.[1492]

In fact, the fourth-year test under Section 4928.143(E) does not *require* the Commission to terminate an ESP.[1493] Instead, that statute provides:

> If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity . . . the commission *may terminate* the electric security plan,

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[1488] R.C. 4928.143(E); Hearing Tr. Vol. XXXVI, p. 7569.

[1489] OCC/NOAC Brief, p. 53.

[1490] *See* Sections III.A.1 and III.A.2., above, and Section V, below.

[1491] *See* Section V.B., below. *See also* Hearing Tr. Vol. XXXVI, pp. 7556-60 (Mikkelsen Cross).

[1492] Companies' Initial Brief, Section III(B); *see also* Hearing Tr. Vol. XXXVI, pp. 7569-70 (Mikkelsen Cross).

[1493] *See* OCC/NOAC Brief, p. 53; CMSD Brief, p. 40.

> but not until it shall have provided interested parties with notice and an opportunity to be heard.[1494]

Intervenors' claims notwithstanding, there is nothing unreasonable about extending Riders RRS and DCR beyond the premature termination of Stipulated ESP IV. Indeed, Stipulated ESP IV's extension of the riders is consistent with the statute. Section 4928.143(E) allows the Commission to impose conditions on the termination of an electric security plan, including provisions to mitigate the transition to another plan.[1495] Section 4829.143(B) also contemplates that certain cost recovery and deferral provisions may extend beyond the term or termination of an electric security plan. For example, as Ms. Mikkelsen testified, if the Commission approved a surcharge under Section 4928.143(B)(2)(c) for construction of a generation facility, then that surcharge could continue for the life of the facility as long the energy capacity was committed to the State.[1496]

The Commission, moreover, has approved other ESPs with riders that extend beyond the time period of the plans. For example, Ms. Mikkelsen explained that Rider DSI continued beyond the period of the Companies' ESP I into the Companies' ESP II.[1497] She also testified that "the Companies agreed to absorb certain legacy RTEP costs in the ESP II stipulation and that commitment extended beyond the term of the ESP."[1498]

Rider DCR and Rider RRS provide multiple important benefits to customers. Among other things, they promote reliable electric service and stable rates. Thus, continuing these riders is reasonable and in the public interest. The transition provision in Stipulated ESP IV is

[1494] R.C. 4928.143(E) (emphasis added).

[1495] R.C. 4928.143(E) ("The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative.").

[1496] Hearing Tr. Vol. XXXVI, p. 7566 (Mikkelsen Cross).

[1497] Hearing Tr. Vol. XXXVI, p. 7564 (Mikkelsen Cross).

[1498] Hearing Tr. Vol. XXXVI, p. 7564 (Mikkelsen Cross).

consistent with Section 4928.143 and the Commission's approval of past electric security plans. Thus, intervenors' arguments to the contrary are without merit and the Commission should reject OCC/NOAC's and CMSD's suggested modification to Section V.K. of the Third Supplemental Stipulation.

S. Stipulated ESP IV Supports At-Risk Customers.

OCC/NOAC claim that the Stipulated ESP IV does not provide sufficient benefits to at-risk customers.[1499] The opposite is true. Stipulated ESP IV clearly protects at-risk customers. In the Application, the Companies proposed to continue funding the Community Connections program valued at $5 million per year, to assist low-income customers through installation of a variety of energy efficiency projects.[1500] This commitment was expanded in the Third Supplemental Stipulation in the amount of $6 million per year for eight years.[1501] In the December 22, 2014 Stipulation and Recommendation, the Companies provided assistance to low income customers through a fuel fund for customers of CEI in the amount of $1.39 Million for each year of the ESP.[1502] The fuel fund was further expanded by the Third Supplemental Stipulation to the customers of Ohio Edison and Toledo Edison in the amount of $1 million per year for eight years.[1503] In total, Stipulated ESP IV will provide over $19 million in funding to assist low income customers with the payment of their electric bills.[1504]

OPAE, one of the signatory parties to the Stipulated ESP IV, specifically serves and advocates on behalf of low income and at risk populations about which OCC/NOAC are

[1499] OCC/NOAC Brief, pp. 99-102.

[1500] Application, p. 19.

[1501] Third Supp. Stip., p. 17.

[1502] Stipulation, pp. 13-14. This term has been extended from three to eight years as a result of the Third Supplemental Stipulation. Third Supp. Stip., Section V.G.4.b.i.

[1503] Third Supp. Stip., Section V.I.4.

[1504] Sierra Club Ex. 89 (Mikkelsen Nov. 30, 2015 Workpaper).

concerned.[1505] Moreover, the Companies also will provide $8 million in funding to jumpstart the creation of a Customer Advisory Agency.[1506] The $19 million in fuel fund dollars and $8 million for the Customer Advisory Agency is not being recovered from customers.[1507] All of these programs are in addition to PIPP, HEAP and HWAP programs that already assist low income and at-risk customers in the Companies' service territories.[1508]

OCC/NOAC rely on OCC witness Williams' testimony in an attempt to support its contention that Stipulated ESP IV does not provide sufficient benefits to at-risk customers.[1509] However, Mr. Williams' testimony is inherently flawed in several ways. First, Mr. Williams submitted his testimony on December 22, 2014 – the same day as the Companies filed the Stipulation and Recommendation and almost a year before the Companies filed their Third Supplemental Stipulation. Mr. Williams did not supplement or update his testimony.

Second, as OCC/NOAC's citation to Mr. Williams' testimony demonstrates, he considered only the Community Connections program from the original Application and even then mistakenly believed that it only applied to CEI customers – which was clearly wrong.[1510] Because Mr. Williams' testimony did not consider any of the benefits to at-risk customers outlined above, the Commission should disregard it.

[1505] Hearing Tr. XXIX, p. 6028 (Rinebolt Cross).

[1506] Sierra Club Ex. 89 (Mikkelsen Nov. 30, 2015 Workpaper).

[1507] Third Supp. Stip., p. 17; Hearing Tr. XXXVI, p. 7735 (Mikkelsen Cross).

[1508] Hearing Tr. XXIX, pp. 6033-6034; 6036-6039 (Rinebolt Cross).

[1509] OCC/NOAC Brief, pp. 99-102. Mr. Williams offered no definition of at-risk population and admits that it is a broadly used term. Hearing Tr. XXVIII, pp. 5766, 5772 (Williams Cross).

[1510] OCC/NOAC Brief, pp. 99-100; Direct Testimony of Eileen Mikkelsen, p. 16 (explaining that the Community Connections program applies "across [the Companies] service territories". Mr. Williams also criticized the Companies' removal of the PIPP discount which admits that the Companies could not have actually provided. Hearing Tr. XXVIII, p. 5775 (Williams Cross).

Third, Mr. Williams' testimony as to the poverty levels in the counties served by the utilities is flawed.[1511] In his chart listing poverty levels in the Companies' service territories, Mr. Williams does not include all the counties in the Companies' service territories and fails to identify several counties where the poverty level is actually quite low.[1512] Simply put, Mr. Williams cherry-picked data that suited his incorrect conclusion. Mr. Williams also agreed that poverty is a statewide issue not exclusive to the Companies.[1513] Mr. Williams further relied on Cuyahoga County that is also served by a large municipal utility.[1514] Mr. Williams' testimony on poverty levels simply cannot be relied upon.

OCC/NOAC lack record support for its suggestion that the number of customers whose electric service is terminated for non-payment may increase under Stipulated ESP IV.[1515] Again, OCC/NOAC's reliance on Mr. Williams' testimony is misplaced. Citing to flawed statistics as noted above, Mr. Williams claims that a large number of the Companies' customers who are disconnected for non-payment are not getting service restored.[1516] However, Mr. Williams admitted that he does not know: (1) all of the reasons a customer may have been disconnected; (2) all of the factors that could contribute to the disconnection rates; and (3) why a customer may or may not have electric service reconnected.[1517] OCC/NOAC's speculation and Mr. Williams' flawed testimony should be disregarded.

[1511] OCC/NOAC Brief, p. 99.

[1512] Hearing Tr. XXVIII, pp. 5776-5780 (Williams Cross).

[1513] Hearing Tr. XXVIII, p 5771 (Williams Cross).

[1514] Hearing Tr. XXVIII, p. 5779 (Williams Cross).

[1515] OCC/NOAC Brief, pp. 101-02.

[1516] *Id.*

[1517] Hearing Tr. XXVIII, pp. 5783-5785 (Williams Cross).

V. ESP IV IS MORE FAVORABLE IN THE AGGREGATE THAN THE EXPECTED RESULTS OF AN MRO

As the record in this proceeding amply demonstrates, Stipulated ESP IV is more favorable in the aggregate as compared to the expected results that would otherwise apply under an MRO. Indeed, the benefits and protections afforded to customers under Stipulated ESP IV are manifestly quantitatively and qualitatively superior to the results that would occur under an MRO. Accordingly, the Commission should approve Stipulated ESP IV without modification.

Stipulated ESP IV provides a quantitative benefit of $612.1 million on a nominal basis and $296 million on a net present value basis to customers over the expected results of an MRO. These benefits are calculated under methods set by Commission precedent for determining ESP benefits under the "ESP v. MRO" test.[1518]

A number of parties addressed the ESP v. MRO test issue, often in a manner at odds with the actual language of Section 4928.143(C)(1). They did so by ignoring words in the statute in an effort to undermine the value of Stipulated ESP IV and distort the test.[1519] The language of Section 4928.143(C)(1) is hardly ambiguous. Indeed, no party contends otherwise. The statute provides:

> Subject to division (D) of this section, the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing *and all other terms and conditions*, including any deferrals and any future recovery of deferrals, is more favorable *in the aggregate* as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. (Emphasis added)

[1518] *See*, *e.g.*, Case No. 10-388-EL-SSO, *Opinion and Order*, pp. 42; 44 (Aug. 25, 2010); Case No. 12-1230-EL-SSO, *Opinion and Order*, pp. 55-56 (July 18, 2012); *In the Matter of 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. 11-3549-EL-SSO, *Opinion and Order*, pp. 46-47 (Nov. 22, 2011).

[1519] For example, OCC/NOAC incorrectly describe the test at the top of page 51 of their brief.

The arguments in opposition to Stipulated ESP IV's qualification under the statutory test are without support under the very statute at issue. OCC/NOAC contend no ESP should ever be approved. OCC/NOAC argue this, even though the statute specifically provides for ESPs. NOPEC, using a strained and improper tour through some "legislative history," argues that qualitative factors shouldn't be considered. NOPEC argues this, even though the statute says no such thing and the Commission and the Ohio Supreme Court say otherwise. These parties also contend that the Stipulated ESP IV quantitatively fails the ESP v. MRO test based on: (1) a reliance on Mr. Wilson's biased and unreliable calculations regarding the impact of Rider RRS; (2) a claim that Rider DCR should count as an ESP cost, contrary to Commission precedent; (3) an incorrect assertion that economic development and low income funding commitments would occur in an MRO; (4) a view that certain riders, proposed to be set at zero, really do have and should have costs and thus should be reflected as ESP costs. On the qualitative comparison of Stipulated ESP IV, these parties assert, again contrary to Commission precedent, that ESP provisions that promote reliable service and stable rates shouldn't count as qualitative benefits of an ESP. In each instance, these arguments are unsupported by the law or the record and, as such, they should be rejected.

A. ESPs Are An Appropriate Way To Provide A Standard Service Offer.

It should go without saying that an ESP is a proper vehicle for extended standard service offer. ESPs are expressly provided for in Section 4928.143. Multiple ESPs have been approved by the Commission.[1520] Indeed, the Commission has denied the only two applications ever submitted for approval of an MRO.[1521]

[1520] *See, e.g.* Case No. 12-1230-EL-SSO, Opinion and Order (July 18, 2012) approving the Companies' ESP III); Case No. 10-388-EL-SSO, Opinion and Order (Aug. 25, 2010) (approving the Companies' ESP II); Case No. 11-346-EL-SSO, Opinion and Order (Dec. 14, 2011) (approving AEP's ESP II); Case No. 11-3549-EL-SSO, Opinion

Yet curiously, OCC/NOAC contend that the time has come to abolish ESPs – and, on that basis, reject Stipulated ESP IV here.[1522] The thin authority for this paradigm changing argument is the testimony of OCC/NOPEC witness Kahal, who, in return, relied on a *concurring* opinion of former Commissioner Snitchler in Case No. 12-3151-EL-COI.[1523] Yet even Mr. Kahal understood that a concurring opinion is hardly controlling.[1524] Further, Mr. Kahal admitted that the quote from that concurring opinion could be fairly read to be advice as to *what the legislature should do.*[1525] Of course, the Commission has no authority to bar or abolish ESPs. Indeed, this Commission has a duty to approve an ESP if it finds that it satisfies the criteria in Section 4928.143(C).

B. The ESP v. MRO Test Properly Contemplates The Consideration Of Qualitative Factors.

NOPEC attempts to argue, against both Commission and Supreme Court of Ohio precedent, that qualitative factors should not be considered in the ESP v. MRO test. To do so, NOPEC weaves a tortured path through the "legislative history" of the statute.[1526] NOPEC's extensive reliance on the "legislative history" of Section 4928.143(C)(1) is wholly

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and Order (Nov. 22, 2011) (approving Duke's ESP II); Case No. 08-1094-EL-SSO, Opinion and Order (June 24, 2009) (approving DP&L's ESP I).

[1521] *See generally* Case No. 10-2586-EL-SSO, Opinion and Order (Feb. 23, 2011) (finding MRO application could not proceed as filed); Case No. 08-0936-EL-SSO, Opinion and Order (Nov. 25, 2008) (denying application for approval of a proposed MRO).

[1522] OCC/NOAC Brief, pp. 4-5.

[1523] Hearing Tr. Vol. XXIV, pp. 4880-81(Kahal Cross).

[1524] Hearing Tr. Vol. XXIV, p. 4881 (Kahal Cross).

[1525] Hearing Tr. Vol. XXIV, p. 4881 (Kahal Cross). Notably, Mr. Kahal did not review whether his clients took the same view in that case as he does here. Hearing Tr. Vol. XXIV, p. 4882 (Kahal Cross).

[1526] NOPEC Initial Brief, pp. 52 et al. and Appendices A-D. Notably, however, the Ohio Supreme Court has observed that Ohio statutes have no legislative history. *State v. Dickinson*, 28 Ohio St.2d 65, 67 (1971) ("[N]o legislative history of statutes is maintained in Ohio.")

inappropriate.[1527] Specifically, the Supreme Court of Ohio recently criticized a dissenting opinion because it relied on testimony before the Senate and House committees. The Court explained that "[t]his information is unpersuasive because Ohio does not maintain a comprehensive legislative history of its statutes. Instead, we rely on the language the General Assembly chose and our long-established rules of statutory construction."[1528] Further, the Supreme Court of Ohio has established that legislative history of a statute should not be considered unless the language of the statute is first determined to be ambiguous.[1529] Here, NOPEC does not contend that the language in Section 4928.143(C)(1) is ambiguous. This failure eliminates the need to refer to any "legislative history" regarding this statute.[1530] The Commission, moreover, has not found that the ESP v. MRO test under Section 4928.143(C)(1) is ambiguous regarding the issue that NOPEC argues in its brief, i.e. whether qualitative factors should be considered. Rather, the Commission has repeatedly held that its analysis of this test requires consideration of qualitative factors.[1531]

[1527] The Commission has rejected other belated efforts to introduce materials via a party's brief. See In the Matter of FAF, Inc., Notice of Apparent Violation and Intent to Assess Forfeiture, PUCO Case No. 06-786-TR-CVF, 2006 WL 3932766, at *1 (Opinion and Order dated November 21, 2006) (granting motion to strike and holding that "[d]ocuments that are not part of the record, and that were not designated a late-filed exhibit at hearing, cannot be attached to a brief, or filed after a hearing, and thereby be made a part of the record.").

[1528] *State v. South*, 144 Ohio St. 3d 295, 301 (2015).

[1529] *Dunbar v. State*, Case No. 2012-0565, 2013-Ohio-2163, ¶ 16 (May 30, 2013) (Slip Op.) ("[I]nquiry into . . . legislative history . . . or any other factors identified in R.C. 1.49 is inappropriate absent an initial finding that the language of the statute is, itself, capable of bearing more than one meaning.").

[1530] Even if the Commission were to consider the documents improperly attached to NOPEC's Initial Brief, there is nothing there that would support the Commission's departure from its, and the Court's, precedent regarding the long-standing analysis under the ESP v, MRO test. Reviewing the different versions of SB 221 that were not enacted into law may be of academic interest to some, NOPEC's conclusions about what happened during that process are wholly unsupported, and often times simply wrong.

[1531] *In the Matter of the Application of The Dayton Power and Light Company for Approval of its Electric Security Plan*, Case No. 12-426-EL-SSO, Opinion and Order, 2013 Ohio PUC LEXIS 193 at *125 (Sept. 4, 2013); *In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 12-1230-EL-SSO, Opinion and Order at pp. 55-57 (July 18, 2012); *In the Matter of Columbus Southern Power Company and Ohio Power Company for Authority to Provide for a Standard Service*

What's more, the interpretation of Section 4928.143(C)(1) suggested by NOPEC conflicts with the plain language of the statute. NOPEC contends that the reference in Section 4928.143(C)(1) to "all other terms and conditions" "refers only to pricing and cost considerations."[1532] But the language of Section 4928.143 includes no such restriction. Section 4928.143(C)(1) provides that the Commission shall approve an ESP:

> [if] it finds that the electric security plan so approved, *including its pricing and all other terms and conditions*, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142 of the Revised Code.[1533]

By including the phrase "*and* all *other* terms and conditions," the statute sets "all other terms and conditions" apart from and in addition to "pricing." By so doing, the statute expressly instructs the Commission to consider issues *other* than price. Indeed, the Supreme Court of Ohio has read Section 4928.143(C)(1) to say exactly that.

In *In re Application of Columbus S. Power Co.* ("*CSP I*"), the Supreme Court of Ohio rejected a party's attempt to impose a limitation on the Commission's analysis under Section 4928.143(C)(1).[1534] The Court held that comparing an ESP to an expected MRO "does not bind the commission to a strict price comparison."[1535] The Court observed, "in evaluating the favorability of a plan, the statute [Section 4928.143(C)(1)] instructs the commission to consider 'pricing *and all other terms and conditions*.'"[1536] As a result, the Court held that "the

Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Case No. 11-346-EL-SSO, Opinion and Order at pp. 73-77 (August 8, 2012).

[1532] NOPEC Brief, p. 55.

[1533] R.C. 4928.143(C)(1).

[1534] *In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 402, 2011-Ohio-958, 945 N.E.2d 501, ¶ 27.

[1535] *Id*.

[1536] *Id*. (emphasis in original)

commission *must* consider more than price in determining whether an electric security plan should be modified."[1537]

NOPEC further presents an erroneous reading of another case, *In re Application of Columbus S. Power Co.* ("*CSP II*").[1538] In that case, the Court held that an ESP could only include those items listed in Section 4928.143(B).[1539] Terming the provisions listed in that section as "cost recovery" items, NOPEC contends that only costs can be considered under the ESP v. MRO test.[1540] The *CSP II* Court said nothing of the sort. Indeed, the holdings of the *CSP I* and *CSP II* Courts meld neatly together. The *CSP II* holding commands that, to be part of an ESP properly, all of the ESP's provisions must fall within Section 4928.143(B). Then, under *CSP I,* all authorized provisions of an ESP must be weighed – including price "and all other terms and conditions" – against the results obtained under an MRO.

Regardless of the precedent against NOPEC's reading of the statute, NOPEC's proposed interpretation of Section 4928.143(C)(1) faces another problem: it would read "all other terms and conditions" out of the statute. This conflicts with the rule of statutory construction that requires all words of a statute to have meaning.[1541]

By directing the Commission to consider "price," the statute, of course, mandates a weighing of the respective costs – hence quantitative factors – of an ESP versus an MRO. But by additionally directing the Commission to consider "all other terms and conditions," the statute necessarily permits consideration of non-quantitative factors or, as labeled by the Commission,

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[1537] *Id*. (emphasis in original).

[1538] 128 Ohio St. 3d 512, 2011-Ohio-1788, 945 N.E.2d 655

[1539] *Id.* at 520.

[1540] NOPEC Brief, p. 54.

[1541] *State ex rel. Carna v. Teays Valley Local Sch. Dist. Bd. of Educ*., 131 Ohio St.3d 478, 2012-Ohio-1484, 967 N.E.2d 193, ¶ 18 ("Venerable principles of statutory construction require that in construing statutes, we must give effect to every word and clause in the statute.").

qualitative factors. Indeed, if the General Assembly had intended to limit the Commission's analysis under Section 4928.143(C)(1) to only costs, then it would have expressly said so.[1542] Or the General Assembly could have used terms to describe the test as cost-focused. (For example, the General Assembly could have said that the ESP must be "less costly" than an MRO. Or it could have said that an ESP must be "quantitatively more favorable" than an MRO.) The General Assembly did none of these things.

Instead, the General Assembly chose to use the terms "*pricing and all other terms and conditions*", and "more favorable *in the aggregate*," the plain meaning of which is "considered as a whole."[1543] A consideration of the pricing and terms and conditions as a whole stands in stark contrast to the narrow, restricted analysis that NOPEC proposes. Accordingly, NOPEC's proposed interpretation of Section 4928.143(C)(1) conflicts with the plain meaning of the statute and must be rejected.

C. Stipulated ESP IV Is Quantitatively Superior To An MRO.

Some of the parties opposing Stipulated ESP IV argue that it is not more favorable than an MRO. They assert, in turn: (1) the benefit of Rider RRS is not $561 million; (2) Rider DCR should be considered to be a cost of the ESP; (3) funding commitments to support low income and economic development should not be considered a quantitative benefit; and (4) other provisions that could have an impact on customers were not quantified. Each of these criticisms lacks merit.

1. Rider RRS is a $561 million benefit to customers.

[1542] *Cf. MP Star Fin., Inc. v. Cleveland State Univ.*, 107 Ohio St.3d 176, 2005-Ohio-6183, 837 N.E.2d 758, ¶¶ 8–9 ("Had the General Assembly intended to make [the statute narrower] . . . it would have done so by adding qualifying language.").

[1543] *Webster's Third New International Dictionary* 41 (1986), Supp., pp. 327-328.

As discussed in the Companies' Initial Brief at pages 11-16 and in Section III.A.1. above, the Companies appropriately quantified the benefits of Rider RRS. Rider RRS has a net benefit to customers of $561 million, as explained in the testimonies of witnesses Rose, Lisowski, Ruberto, and Mikkelsen. The Companies put forward the only reliable forecasts in this case. Arguments by the opponents of Stipulated ESP IV that Rider RRS is a cost rely on the projections regarding the potential impact of Rider RRS that, in turn, are based on either unsupported ad hoc and erroneous rationalizations or demonstrably unreliable methodology. Accordingly, the Companies' forecast regarding Rider RRS's impact is the best evidence before the Commission.

2. Rider DCR does not have a quantitative impact on the ESP v. MRO Test

Commission precedent considers the recovery of distribution capital costs through Rider DCR to be equivalent to the recovery of similar costs through a distribution base rate proceeding.[1544] OCC/NOAC, NOPEC and OMAEG nevertheless argue that Rider DCR should be included in the quantitative ESP v. MRO test.[1545] Company witness Fanelli explained in his Direct Testimony why this is wrong:

> Consistent with the Commission's decision in the Companies' most recent ESP III case and other companies' cases, because these distribution-related capital costs would also be recoverable under an MRO through a base distribution rate case, there is no quantifiable cost of the proposed ESP IV associated with this provision.[1546]

[1544] *See* Case No. 12-1230-EL-SSO, Opinion and Order, p. 56 (July 18, 2012) ("[T]hese costs should be considered substantially equal and removed from the ESP v. MRO analysis.").

[1545] OCC/NOAC Brief, p. 53; NOPEC Brief, p. 59-61; OMAEG Brief, p. 60-61. OCC/NOAC's attempt at page 56 of their brief to suggest that Staff presently opposes Rider DCR is both inappropriate and amounts to nothing more than OCC/NOAC relying upon outdated testimony that no longer reflects the Staff's position in a futile attempt to overturn Commission precedent.

[1546] Fanelli Direct, p. 7 (citing Case No. 12-1230-EL-SSO, Opinion and Order, pp. 55-56 (July 18, 2012); Case No. 11-346-EL-SSO, Opinion and Order, p. 31 (Dec. 14, 2011)). Companies' Initial Brief, p. 17.

At hearing, counsel for OCC attempted to establish that there may be timing differences between the recovery under Rider DCR and recovery under a base rate case. Mr. Fanelli explained why that comparison was irrelevant:

> As has been established in the prior cases that I referenced in my testimony, while there could be timing difference between those recoveries, the interpretation from the Commission's perspective with regards to the test has been to treat those costs as neutral because they would be recovered either way, albeit subject to some slight timing differences potentially.[1547]

Therefore, Rider DCR has no quantitative impact on the ESP v. MRO test.

NOPEC contends that the Commission should not follow its longstanding precedent. NOPEC baldly contends, "The plain meaning of the statute [Section 4928.143(C)(1)] clearly limits the Commission's analysis to the expected results of Section 4928.142, and does not contemplate consideration of the results of a distribution rate case."[1548] But NOPEC fails to show that the Commission's analysis under Section 4928.143(C)(1) is so limited.

In any event, NOPEC is plainly wrong. Section 4928.143(C)(1) allows the Commission to consider whether the pricing and all other terms and conditions of an ESP would be more favorable in the aggregate than the "expected results" that would otherwise apply under an MRO.[1549] This language does not limit the Commission's analysis to only the generation costs under an MRO. The statute directs the Commission to consider whether a utility's nonshopping customers would be better off under the proposed ESP or if a hypothetical MRO was in place. Given that Section 4928.143(B) permits an ESP to contain certain types of distribution charges, where an ESP contains such charges, in order to make the statutory comparison of all terms and conditions in the aggregate, the Commission must consider whether and how those distribution

[1547] Hearing Tr. Vol. XX, p. 3929 (Fanelli Cross).

[1548] *Id*.

[1549] R.C. 4928.143(C)(1).

charges would be recovered without that ESP. The Commission's consideration of how a distribution rate case would impact customers if the Commission approved an MRO fits within a consideration of the "expected results" that would otherwise apply if an MRO was in place. This Court should reject NOPEC's argument that the Commission's quantitative analysis was unlawful because it considered how certain distribution costs, proposed to be recovered in Stipulated ESP IV, could be recovered in a situation where the Companies' provided SSO service under an MRO.

3. The Companies' economic development and low income funding commitments should be included as a quantitative benefit in the ESP v. MRO Test.

In Stipulated ESP IV, the Companies commit to providing to support low income customers, as well as economic development and job retention activity in their service territories.[1550] Despite these commitments, some oppose the inclusion of these funds as a quantitative benefit of the ESP because similar commitments could be made by the Companies under an MRO.[1551] These claims are misguided. Whether the Companies theoretically could or could not make similar funding commitments under an MRO is irrelevant because, as Companies' witness Mikkelsen explained, these funding commitments are being made specifically as part of the proposed ESP and they would not exist otherwise.[1552] There certainly isn't any precedent for such commitments being required by the Commission in a distribution base rate case. Indeed, NOPEC cites to none. In any event, similar funding commitments have

[1550] Companies' Initial Brief, pp. 102, 106-107.

[1551] NOPEC Brief, p. 63-64; OMAEG Brief, p. 61; RESA Brief, p. 38; Exelon Brief, pp. 44-46; EPSA/P3 Brief, pp. 32-33.

[1552] Hearing Tr. Vol. XXXVI, pp. 7735-7736 (Mikkelsen Cross).

been recognized by the Commission as quantitative benefits in the Companies' prior ESPs.[1553] Therefore, these funding commitments are appropriately included as quantitative benefits of the ESP in the ESP v. MRO Test.

4. The quantitative analysis presented by the Companies is complete.

Certain parties also contend that the Companies' quantitative analysis of the ESP v. MRO test failed to include other provisions of the proposed ESP. Specifically, NOPEC and OMAEG argue that the costs associated with Rider GDR, Rider ELR, the HLF TOU rate, energy efficiency programs (including increased low income funding), battery technology, renewable resources, and grid modernization should be included as part of the costs of an MRO.[1554]

As it relates to Rider GDR, NOPEC claims that it is unreasonable to recognize the value at zero.[1555] As Companies' witness Mikkelsen explained, there currently are no estimates for Rider GDR at this time so there is no estimate to include in the test.[1556] Further, if any amounts are to be included in the Rider GDR following approval of the rider in this proceeding, those amounts will be approved by the Commission in a separate proceeding. Given that Rider GDR is intended to recover costs related to implementing programs required by legislative or governmental directives[1557], such costs would reasonably be expected to be incurred and recovered whether under an ESP or an MRO. Further, the Commission has previously approved

[1553] *See* Case No. 12-1230-EL-SSO, Opinion and Order, pp. 48-56 (July 18, 2012); Case No. 10-388-EL-SSO, Opinion and Order, p. 44 (Aug. 25, 2010).

[1554] NOPEC Brief, pp. 57-59; OMAEG Brief, pp. 59-60.

[1555] NOPEC Brief, p. 57.

[1556] Mikkelsen Direct, pp. 24-25.

[1557] Companies' Initial Brief, p. 89.

placeholder riders as part of ESPs and properly did not include any costs for such riders in the ESP v. MRO comparison.[1558]

Similarly, with regard to Rider ELR and the HLF TOU rate, Companies' witness Mikkelsen pointed out at hearing that these provisions have a net zero quantitative impact across the Companies' customers and therefore there is no net cost to be explicitly recognized in the test.[1559] It is also inappropriate to include in the test any costs associated with energy efficiency provisions of the ESP IV, including the Community Connections program for low income customers, because "these costs or greater costs would need to be incurred in order for the [C]ompanies to meet the state benchmarks associated energy efficiency.[1560] Therefore, such costs would arise in similar fashion whether under an ESP or MRO. The exclusion of these types of provisions in the quantitative analysis of the ESP vs. MRO test is consistent with Commission Orders in the Companies' prior ESPs.[1561]

Regarding battery technology, renewable resources, and grid modernization initiatives, Companies' witness Mikkelsen explained at hearings that it is premature to assume that there will be any costs associated with these provisions[1562] because each one is contingent upon future, independent Commission approval to move forward and incur costs.

RESA and EPSA/P3 argue that no amount may be included in the ESP v. MRO test as a quantitative benefit unless the amount is actually known at the time the analysis under Section 4928.143(C)(1) is conducted by the Commission or a specific outcome is guaranteed by the

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[1558] *See AEP ESP3* Order, p. 94 ("[I]n light of . . . the fact that the [riders] have been set at zero, it is not necessary to attempt to quantify the impact of any of these riders in the MRO/ESP analysis").

[1559] Hearing Tr. Vol. XXXVII, pp. 7799-7800 (Mikkelsen Cross).

[1560] Hearing Tr. Vol. XXXVII, p. 7799 (Mikkelsen Cross).

[1561] *See* Case No. 12-1230-EL-SSO, Opinion and Order, pp. 48-56 (July 18, 2012); Case No. 10-388-EL-SSO, Opinion and Order, p. 44 (Aug. 25, 2010).

[1562] Hearing Tr. Vol. XXXVII, p. 7799 (Mikkelsen Cross).

Companies.[1563] Such a position is untenable and is inconsistent with the language of ESP v. MRO test itself. Frankly, to suggest that the Commission may not rely upon estimates or forecasts in analyzing whether an ESP is more favorable than an MRO would mean that no ESP could ever pass the test, effectively rendering the ESP option under the statute an impossibility. In fact, the statutory language specifically contemplates that the Commission will have to conduct the test with forecasts and estimates; the statute requires the Commission to assess the "expected results" of an MRO.[1564] Nowhere in the statute is there any requirement that the Commission must know or use the actual cost or impacts of an ESP. If such an onerous provision were intended, the General Assembly would have expressly included it.

D. ESP IV Is Qualitatively Superior To An MRO.

The Companies have presented reams of evidence over months of hearings addressing the qualitative benefits of the ESP as compared to a hypothetical MRO. These benefits include a wide array of factors including that:

- Economic Stability Program provides benefits of fuel and resource diversity, environmental compliance, and avoidance of transmission capital expenditures.[1565]
- Rider RRS provides long-term rate stability.[1566]
- Base distribution rate freeze provides stability to customers.[1567]
- Rider DCR and Rider GDR allow the Companies to invest more efficiently than otherwise would occur. Rider DCR provides additional customer protections through a formal audit process.[1568]

[1563] EPSA/P3 Brief, p. 35; RESA Brief, pp. 37-39

[1564] R.C. 4928.143(C)(1).

[1565] Companies' Initial Brief, pp. 24-30. Hearing Tr. Vol. XX, pp. 3981-84 (Fanelli Cross).

[1566] Companies' Initial Brief, pp. 22-24. Strah Direct, pp. 7-11, Figure 1 (as amended by errata)).

[1567] Companies' Initial Brief, pp. 80-81. Fanelli Direct, p. 9; Case No. 12-1230-EL-SSO, Opinion and Order, p. 56 (July 18, 2012); Hearing Tr. Vol. XX, p. 3901 (Fanelli Cross).

[1568] Companies' Initial Brief, pp. 82, 89-91. Hearing Tr. Vol. XX, pp. 3926-28 (Fanelli Cross); Fanelli Direct, p. 9.

- Supplier web portal and proposed changes to Supplier Tariffs and Electric Service Regulations support retail competition by removing barriers.[1569]

- Low income support through Community Connections.[1570]

- Continuation of Rider ELR provides economic development and job retention benefits to participating customers.[1571]

- Continuation of Rider ELR provides benefits to all customers from a system reliability perspective.[1572]

- Allowing Rider ELR customers to shop supports the competitive retail market.[1573]

- Continuation of Automaker Credits provides economic development and job retention benefits to qualifying customers by encouraging increased production within the state.[1574]

- Slower phase-out of Rider EDR(d) will allow Rate GT customers to more gradually transition to market based pricing.[1575]

- Continuation of a time-of-day pricing option under Rider GEN will enhance customers' opportunities to lower their electric bills, and also provide an opportunity for customers to learn about time-differentiated pricing.[1576]

- Rider NMB Pilot provides customer optionality, education, and an opportunity for savings and better aligns costs with costs causation.[1577]

- Commercial HLF TOU rate provides eligible customers an opportunity to reduce their costs and learn about time-of-use rates.[1578]

[1569] Companies' Initial Brief, pp. 35-36. Fanelli Direct, p. 9; Hearing Tr. Vol. XX, p. 3940 (Fanelli Cross).

[1570] Companies' Initial Brief, pp. 18, 106. Hearing Tr. Vol. XX, p. 3939-40 (Fanelli Cross).

[1571] Companies' Initial Brief, p. 108. Mikkelsen Supp., pp. 11-12; Hearing Tr. Vol. II, p. 274 (Mikkelsen Cross).

[1572] Companies' Initial Brief, p. 108. Mikkelsen Supp., pp. 11-12; Hearing Tr. Vol. II, p. 244 (Mikkelsen Cross); Tr. Vol. III, pp. 494-95 (Mikkelsen Cross).

[1573] Companies' Initial Brief, p. 36. Mikkelsen Supp., pp. 11-12.

[1574] Companies' Initial Brief, p. 148. Mikkelsen Supp., pp. 11-12; Hearing Tr. Vol. III, pp. 622-23 (Mikkelsen Cross).

[1575] Companies' Initial Brief, p. 103. Mikkelsen Supp., pp. 11-12; Hearing Tr. Vol. I, p. 177 (Mikkelsen Cross); Hearing Tr. Vol. III, p. 623-24 (Mikkelsen Cross).

[1576] Companies' Initial Brief, pp. 34, 104. Mikkelsen Supp., pp. 11-12.

[1577] Companies' Initial Brief, pp. 34-35, 104. Mikkelsen Third Supp., p. 2.; Hearing Tr. Vol. II, p. 470; Hearing Tr. Vol. III, p. 642 (Mikkelsen Cross).

[1578] Companies' Initial Brief, pp. 35, 104. Mikkelsen Fourth Supp., p. 2; Hearing Tr. Vol. III, p. 463 (Mikkelsen Cross).

- Federal advocacy for a longer term capacity product.[1579]
- Business case filing for grid modernization.[1580]
- Environmental stewardship goal to reduce CO2 by at least 90% below 2005 levels by 2045.[1581]
- Battery resource investment evaluation.[1582]
- Robust energy efficiency offerings beginning in 2017.[1583]
- Increased in-state renewable resources.[1584]
- Commitment to file a case to transition to decoupled residential base distribution rates.[1585]
- Amend the partial service tariffs and modify the Electric Service Regulations.[1586]
- ESP provides more flexibility to the PUCO compared to MRO.[1587]

In contrast, OCC/NOAC would have the Commission assign no value to residential customers: 1) for increased energy efficiency programs and reduction in CO2 levels;[1588] in retaining thousands of jobs and avoiding potentially billions in revenue requirement associated with additional transmission investment;[1589] fuel diversity and system reliability;[1590] and rate stability. OCC/NOAC's position is that these types of qualitative benefits work against customer

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[1579] Companies' Initial Brief, pp. 110-111. Mikkelsen Fifth Supp., p 13; Third Supp. Stip., Section V.C.

[1580] Companies' Initial Brief, p. 31. Mikkelsen Fifth Supp., p. 13; Third Supp. Stip., Section V.D.

[1581] Companies' Initial Brief, p. 31. Mikkelsen Fifth Supp., p 13; Third Supp. Stip., Section V.E.1.

[1582] Companies' Initial Brief, p. 31. Mikkelsen Fifth Supp., p. 13; Third Supp. Stip., Section V.E.2.

[1583] Companies' Initial Brief, p. 31. Mikkelsen Fifth Supp., p 13; Third Supp. Stip. Section V.E.3.

[1584] Companies' Initial Brief, p. 32. Mikkelsen Fifth Supp., p. 13; Third Supp. Stip. Section V.E.4.

[1585] Companies' Initial Brief, p. 32. Mikkelsen Fifth Supp., p 13; Third Supp. Stip. Section V.F.

[1586] Companies' Initial Brief, p. 112. Mikkelsen Fifth Supp., p. 13; Third Supp. Stip. Section V.H.1, 2.

[1587] Companies' Initial Brief, p. 21. Fanelli Direct, p. 9-10.

[1588] OCC/NOAC Brief, p. 67.

[1589] *Id*. p. 62.

[1590] *Id*. p. 64.

interests.[1591] These arguments are facially without merit. Indeed, the Commission has previously correctly found that an ESP provides qualitative benefits when it:

- includes energy efficiency programs;[1592]
- promotes economic development;[1593]
- ensures system reliability;[1594]
- facilitates rate stability.[1595]

OCC/NOAC provide little reason to distinguish Stipulated ESP IV from the previously approved ESPs promoting the same type of qualitative benefits.

NOPEC also opposes including avoided transmission costs as a qualitative benefit on the grounds that someday the Plants will retire and therefore the transmission lines will have to be built eventually. Thus, NOPEC argues, no costs are really avoided.[1596] This position is ridiculous. Even if NOPEC was correct, to conclude that there is no value to customers for deferring billions of dollars in revenue requirements for at least eight years is laughable. In any event, NOPEC's position is wholly without record support and should be rejected.

VI. THE BENCH'S RULINGS WERE APPROPRIATE.

OMAEG and OCC/NOAC ask the Commission to reverse the Attorney Examiner's rulings granting the Companies' motion to strike a portion of Dr. Hill's testimony offered during his redirect examination.[1597] After hearing oral argument on the issue, the Attorney Examiner found Dr. Hill's testimony regarding the Consumer Protection Association addressed a subject

[1591] *Id*. p. 67.

[1592] Case No. 10-388-EL-SSO, Opinion and Order, p. 44 (Aug. 25, 2010)

[1593] *Id.*

[1594] Case No. 12-1230-EL-SSO, Opinion and Order, p. 56 (July 18, 2012).

[1595] *Id*

[1596] NOPEC Brief, p. 68.

[1597] OMAEG Brief, p. 72; OCC/NOAC Brief, p. 46.

matter that was beyond the scope of the matters addressed during his cross examination testimony.[1598]

The Attorney Examiner's ruling follows the Commission's precedent that "redirect examination is limited to the subjects of questions asked on cross-examination."[1599] This limitation makes sense because otherwise a redirect examination could allow a witness to offer additional direct examination testimony in violation of Rule 4901-1-29 of the Ohio Administrative Code. Rule 4901-1-29 requires a party to file and serve written copies of an expert's direct testimony before offering that testimony at hearing.

Neither OMAEG nor OCC/NOAC point to any question asked during Dr. Hill's cross examination that addressed the subject of the stricken testimony, *i.e.*, generally, the Consumer Protection Association. Instead, they argue that Dr. Hill's testimony addressed relevant information regarding the Commission's assessment of a stipulation.[1600] But their arguments are misdirected. Simply put, the relevance of Dr. Hill's testimony has no bearing on the scope of the subject matters addressed during Dr. Hill's cross-examination testimony.

Further, any purported relevance of Dr. Hill's testimony cannot excuse OMAEG's failure to introduce that testimony during his direct examination. They provide the Commission no excuse as to why OMAEG could not have offered this information in Dr. Hill's Third Supplemental Testimony, which was filed on December 30, 2015.[1601] Although OMAEG and

[1598] Hearing Tr. Vol. XXXIX, pp. 8388-93 (Hill Redirect).

[1599] *See In the Matter of the Applications of TNT Holland Motor Express, Inc. to Amend Certificates Nos. 300-R & 407-R.*, PUCO Case No. 89-582-TR-AAC, 1993 WL 13744636, at *1 (Opinion and Order dated Aug. 12, 1993).

[1600] OMAEG Brief, p. 72; OCC/NOAC Brief, p. 48.

[1601] In any event, Dr. Hill's testimony regarding the Consumer Protection Association would also be inadmissible as hearsay. Dr. Hill testified that he did not have direct knowledge of the Consumer Protection Association. He testified that "I hadn't heard of the Consumers Protection Association." (Hearing Tr. Vol. XXXIX, p. 8389 (Hill Redirect).) Instead, his testimony regarding the Consumers Protection Association discussed information that he found through "a news search." (Hearing Tr. Vol. XXXIX, p. 8389 (Hill Redirect).)

OCC/NOAC assert that the information is "new," the materials cited by OMAEG were, with one exception, dated prior to Mr. Hill's prefiled testimony.[1602] OMAEG's attempt to add this information into the record on redirect was simply an improper belated attempt to circumvent the December 30, 2015 filing deadline in this case.[1603]

OCC/NOAC also contend that the Attorney Examiner should have admitted copies of Staff witness Choueiki's prefiled testimony from the Duke ESP case (Case No. 13-841-EL-SSO) and from the *AEP ESP3* case.[1604] At the hearing, the Attorney Examiner denied OCC's motion to admit exhibits containing Dr. Choueiki's prefiled testimony from those cases. The Attorney Examiner explained: "A change in staff position following the direction of the Commission has no probative weight. It is unduly prejudicial, confusing, and misleading, and these exhibits will not be admitted at this time."[1605]

OCC/NOAC complain that the Attorney Examiner's order was "unwarranted" because the Commission has the "capability and expertise to give proper weight to evidence."[1606] But OCC/NOAC overlook that the Attorney Examiner is entrusted with determining what evidence the Commission will review.[1607] The Attorney Examiner was well within his discretion under Rule 4901-1-27 of the Ohio Administrative Code to exclude the exhibits.[1608]

[1602] OMAEG Brief, p. 72, n. 368 (citing information dated Nov. 20, 2015); OCC/NOAC Brief, p. 48 n.157, n. 158 (citing a news story dated August 28, 2015); *id*. at 49 n. 159 (citing information dated November 20, 2015).

[1603] Case No. 14-1297, Attorney Examiner Entry, p. 4 (Dec. 9, 2015).

[1604] OCC/NOAC Brief, p. 171-173.

[1605] Hearing Tr. Vol. XXX, p. 6327 (Choueiki Redirect).

[1606] OCC/NOAC Brief, p. 173.

[1607] *See In the Matter of the Applications of TNT Holland Motor Express, Inc. to Amend Certificates Nos. 300-R & 407-R.*, 1993 WL 13744636, at *1 (noting that the "under Rule 4901-1-27, Ohio Administrative Code attorney examiner is empowered to regulate the course of the hearing").

[1608] *See id*. (noting that the Attorney Examiners are "empowered to regulate the course of the hearing" and have the "dut[y] to move the hearing along towards completion").

OCC/NOAC fail to show that the Attorney Examiner's order excluding Dr. Choueiki's prior testimony falls outside of his discretion. The Commission should reject OCC/NOAC's objection to this order.[1609]

VII. CONCLUSION

Stipulated ESP IV satisfies all three prongs regarding the approval of stipulations and the Commission thereby should find that Stipulated ESP IV is reasonable. Stipulated ESP IV also clearly passes the ESP v. MRO test based upon the evidence of record presented in this proceeding. Thus, for the reasons set forth above, the Commission should approve Stipulated ESP IV without modification.

[1609] The Commission should also reject OCC/NOAC's objection because the admission of Dr. Choueiki's prior testimony now would deny the Companies and other parties the opportunity to cross examine Dr. Choueiki regarding the testimony. Indeed, at the hearing, the Attorney Examiner prohibited the Companies from questioning Dr. Choueiki regarding his prior testimony. Hearing Tr. Vol. XXX, pp. 6273-74 (Choueiki Cross). The Companies pointed out this potential prejudice in their objection to OCC/NOAC's motion to admit transcripts of the testimony into evidence. Hearing Tr. Vol. XXX, p. 6327 (Choueiki Redirect).

Respectfully submitted,

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CERTIFICATE OF SERVICE

I certify that this Post-Hearing Reply Brief was filed electronically through the Docketing Information System of the Public Utilities Commission of Ohio on this 26th day of February, 2016. The PUCO's e-filing system will electronically serve notice of the filing of this document on counsel for all parties. Further, a courtesy copy has been served upon parties via electronic mail.

/s/ N. Trevor Alexander
One of the Attorneys for the Companies

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Summary: Reply Post-Hearing Brief electronically filed by Mr. Nathaniel Trevor Alexander on behalf of Ohio Edison Company and The Cleveland Illuminating Company and The Toledo Edison Company