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

MEMORANDUM CONTRA INTERVENOR APPLICATIONS FOR REHEARING OF OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY

PUBLIC VERSION

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I. INTRODUCTION

The Applications for Rehearing filed by the following intervenors fail to state valid grounds for rehearing: Dynegy, Inc. ("Dynegy"); PJM Power Providers Group and Electric Power Supply Association (collectively, "EPSA"); The Retail Energy Supply Association ("RESA"); Sierra Club ("Sierra Club"); the Cleveland Municipal School District ("CMSD"); The Ohio Schools Council, Ohio School Boards Association, Buckeye Association of School Administrators, and Ohio Association of School Business Officials dba Power4Schools ("P4S"); Northeast Ohio Public Energy Council ("NOPEC"); the Environmental Law and Policy Center, Ohio Environmental Council, and Environmental Defense Fund (collectively, "ELPC"); The Ohio Manufacturers' Association Energy Group ("OMAEG"); and the Ohio Consumers' Counsel and Northwest Ohio Aggregation Coalition ("OCC/NOAC").

The Commission's March 31, 2016 Opinion and Order (the "Order") approving the Stipulated Fourth Electric Security Plan ("Stipulated ESP IV")[1] of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (collectively, "Companies") will help protect retail customers against rising electric prices and volatility in the years ahead.[2] It also affords those customers the opportunity to enjoy the benefits of market-based pricing, economic development, and prudent use of natural resources through increased energy efficiency, use of renewable power and reduced emissions from power plants.[3] In

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[1] "Stipulated ESP IV" is the fourth Electric Security Plan filed August 4, 2014, as amended by the Stipulation and Recommendation filed on December 22, 2014, pp. 1-2, as modified by the Errata filed on January 21, 2015 ("Stipulation"); the Supplemental Stipulation and Recommendation filed on May 28, 2015; the Second Supplemental Stipulation and Recommendation filed on June 4, 2015 ("Second Supplemental Stipulation"); and the Third Supplemental Stipulation and Recommendation filed on December 1, 2015 ("Third Supplemental Stipulation"). *See* Third Supp. Stip., pp. 1-2.

[2] Order, pp. 78-79, 86, 92.

[3] Order, pp. 79, 94-97.

particular, Stipulated ESP IV as approved by the Commission will provide many wide-ranging quantitative and qualitative benefits for the Companies' customers, including:

- retail electric service rate stability, including fair and open competitive bid processes using staggered and laddered procurements and a risk sharing element that assures at least $100 million in credits to customers in Rider RRS;
- a commitment to freeze base distribution rates through the entire eight-year term of Stipulated ESP IV, except in case of emergency conditions under R.C. 4909.16 or if the Companies, with Staff agreement, file for a base distribution rate case that would go into effect prior to June 1, 2024;
- continued investment in the delivery system in support of system enhancement and reliability;
- numerous economic development programs and credits;
- federal advocacy for a longer-term capacity product and other market improvements;
- a commitment to present an innovative plan to the Commission proposing the acceleration of state-of-the-art advancements in the distribution delivery business;
- 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 pursue further development of 800,000 MWh per year of energy efficiency and renewable resources in Ohio;
- a commitment to file a case to transition to decoupled residential base distribution rates;
- retail market enhancements; and
- several provisions that provide support to low-income customers.[4]

As the Commission found in its Order, the Companies' Economic Stability Program and Retail Rate Stability Rider ("Rider RRS") "form the centerpiece" of Stipulated ESP IV.[5] Rider RRS was designed to address the significant challenges that exist in Ohio's retail electric service

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[4] *See* Order, pp. 79, 92-99, 119-20; *see, generally*, Third Supp. Stip.

[5] Order, pp. 78, 80.

industry by helping to safeguard customers from rising market prices and retail rate volatility – the exact concerns that drove the General Assembly to enact S.B. 221 in 2008.[6] While customers have enjoyed the benefits of relatively low and stable market-based retail prices for several years, the Signatory Parties[7] agree – and the Commission recognized in its Order – that retail prices will increase and become more volatile in the future, potentially to a significant degree.[8] By pairing a market-based SSO with the Economic Stability Program, Stipulated ESP IV affords retail customers market benefits while partially protecting them against market risks. Indeed, based on the record, the Commission reasonably determined that Rider RRS is projected to provide customers $256 million of net credits over the eight-year term of Stipulated ESP IV.[9]

Importantly, the Companies' May 2, 2016 Application for Rehearing sought rehearing to remedy several risk-related concerns associated with Rider RRS as modified by the Order, and the Commission granted rehearing on May 11, 2016.[10] If the Commission approves the Companies' proposed modifications to how Rider RRS is calculated (the "Proposal"), Rider RRS will continue to provide all the rate stabilization benefits recognized in the Order, but without

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[6] *See* Order, pp. 78-79, 86. *See also* Stipulation, pp. 1-2.

[7] The "Signatory Parties" are the Companies, Staff, Ohio Power Company, Ohio Energy Group ("OEG"), City of Akron, Council of Smaller Enterprises, Cleveland Housing Network, Consumer Protection Association, Council for Economic Opportunities in Greater Cleveland, Citizens Coalition, Nucor Steel Marion Inc., Material Sciences Corporation, The Association of Independent Colleges and Universities of Ohio, the International Brotherhood of Electrical Workers – Local 245, The Kroger Co., Ohio Partners for Affordable Energy, EnerNOC, and Interstate Gas Supply, Inc. ("IGS"). Stipulation, p. 1. Second Supp. Stip., p. 1; Third Supp. Stip., pp. 22-24 (including the Supplemental Signature Page of IGS). Industrial Energy Users-Ohio has indicated that it does not oppose the Stipulation. May 28, 2015 letter from Samuel Randazzo (filed May 28, 2015).

[8] *See* Stipulation, p. 1; Order, p. 83 ("the Commission does not believe that the evidence supports OCC's and NOPEC's prediction that we have entered a period of energy price utopia").

[9] Order, p. 85.

[10] Companies' AFR, pp. 13-14 (May 2, 2016) (noting Commission's modifications to the Third Supplemental Stipulation to require the Companies to bear the burden of any capacity performance penalties and potentially of any plant outages greater than 90 days, as well as impact of recent Federal Energy Regulatory Commission order). *See EPSA v. FirstEnergy Solutions Corp.*, 155 FERC ¶61,101, FERC Docket No. EL16-34-000, Order Granting Complaint (April 27, 2016) ("FERC Order").

reliance on a purchase power agreement ("PPA") or any other contractual arrangement or involvement of FirstEnergy Solutions Corp. ("FES"). Indeed, Rider RRS will have fewer moving parts and, thus, will present less risk to customers. As an additional benefit, Rider RRS as modified will reduce the time and expense of the rigorous review proposed in the Third Supplemental Stipulation and approved in the Order.[11] And because the hedging function of Rider RRS will be provided directly by the Companies, the Companies will be able to use any Rider RRS revenues to support other Stipulated ESP IV initiatives such as grid modernization.

A fortuitous benefit of this narrow change to the Rider RRS calculation is that it renders moot many of the unfounded concerns raised by intervenors in their applications for rehearing.[12] The cost assumptions and generation/capacity output assumptions that will be used to calculate modified Rider RRS are already in the record.[13] Because these cost and revenue proxies are not dependent on FES's actual operational or market characteristics of the Davis-Besse Nuclear Power Station ("Davis-Besse"), the W.H. Sammis Plant ("Sammis"), and FES's 4.85 percent entitlement from the Ohio Valley Electric Corporation ("OVEC") (collectively, the "Plants"), or otherwise connected to any particular generation facilities, intervenors can no longer argue that:

- The projected costs of the Plants are subject to unexpected cost pressures, such as from higher-than-anticipated environmental compliance costs or operational issues, that could be passed through Rider RRS;[14]
- The projected generation output could be lower because of extended outages or other operational performance concerns;[15]

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[11] *See* Order, pp. 88-91.

[12] Mid-Atlantic Renewable Energy Coalition ("MAREC") submitted a filing styled as an application for rehearing, but MAREC explained that the filing was made to support the Commission's Order in light of the FERC Order. MAREC AFR, p. 1.

[13] Co. Ex. 24 (OVEC costs, MWh and MW); Co. Ex 25 (Sammis and Davis-Besse costs, MWh and MW); Sierra Club Ex. 89 (aggregate costs); Figure 5 and fn. 328 in Companies' Post Hearing Reply Brief (Feb. 26, 2016) (summarizing capacity MW and revenues for 2016/17, 2017/18 and 2018/19 Planning Years.

[14] Rehearing Testimony of Eileen M. Mikkelsen ("Mikkelsen Rehearing Test."), pp. 5-6 (May 2, 2016).

- The projected cleared capacity could be lower, because of the effect of offer strategies, performance penalties, failure of the Plants to clear, or other market performance concerns;[16]

- Customers will be exposed to risks because of FES's alleged lack of incentive to manage plant costs;[17]

- Rider RRS is an anti-competitive subsidy to benefit FES that conflicts with R.C. 4928.02(H);[18]

- Rider RRS conflicts with S.B. 3 and R.C. 4928.38;[19]

- Rider RRS conflicts with corporate separation requirements;[20]

- Rider RRS is preempted by federal law;[21]

- Rider RRS will have adverse market impacts, such as price suppression, new market entry deterrence, or impacts on energy efficiency and peak demand reduction programs;[22] or

- The "rigorous review" and "full information sharing" in Section V.B.3. of the Third Supplemental Stipulation are inadequate.[23]

All of these arguments, which the Commission properly rejected when approving Rider RRS in the Order, depend on Rider RRS being supported by actual costs and actual revenues of FES-owned generation or a PPA with FES. Thus, all of these arguments are now irrelevant and are no longer grist for appeal. In addition, if modified Rider RRS is approved on rehearing by the Commission, this also will render moot the Commission's concerns expressed in the Order

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[15] Mikkelsen Rehearing Test., pp. 5, 6.

[16] Mikkelsen Rehearing Test., pp. 5, 6.

[17] Mikkelsen Rehearing Test., pp. 6, 10.

[18] EPSA AFR, pp. 71-75; Dynegy AFR, pp. 2-6; OCC/NOAC AFR, pp. 39, 45; NOPEC AFR, p. 18; ELPC AFR, pp. 3-12; OMAEG AFR, pp. 26-30; RESA AFR, pp. 22-25.

[19] RESA AFR, pp. 26, 89-90; EPSA AFR, p. 22-23; OCC/NOAC AFR, p. 28.

[20] Dynegy AFR, pp. 14-16; RESA AFR, pp. 27-28; EPSA AFR, pp. 23-25.

[21] CMSD AFR, pp. 21-25.

[22] Sierra Club AFR, p. 21; OMAEG AFR, pp. 30-31, 47-51.

[23] OCC/NOAC AFR, p. 43; Dynegy AFR, pp. 19-21; OMAEG AFR, pp. 51-54.

regarding bilateral affiliate transactions, jurisdictional boundaries, and market offers.[24] Thus, the Commission should deny rehearing on all of these topics.

Moreover, many of the applications for rehearing presented by intervenors merely repeat arguments that the Commission addressed and rejected in the Order. As the Commission has held on countless occasions, a party's mere repetition of an argument that was previously thoroughly considered is not grounds for granting rehearing.[25] And where new arguments are presented, they invariably fail to rely on record evidence or to demonstrate why the Order is unreasonable or unlawful. For these reasons and the reasons set out below, the Companies respectfully request that the intervenors' applications for rehearing be denied.[26]

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

A. The Commission Correctly Found That Serious Bargaining Occurred.

Several intervenors, including OCC/NOAC, NOPEC, OMAEG, EPSA, and RESA, contend that the Commission erred in finding that serious bargaining occurred between the Signatory Parties. Nothing could be further from the truth. As the record demonstrates, and the

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[24] Order, pp. 86-87, 90, 91-92.

[25] *E.g., Wiley v. Duke Energy Ohio, Inc.*, Case No. 10-2463-GE-CSS, 2011 Ohio PUC LEXIS 1276, *6-7 (Nov. 29, 2011) (rejecting an application for rehearing where "the application for rehearing simply reiterates arguments that were considered and rejected by the Commission"); *In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service*, Case No. 10-2586-EL-SSO, 2011 Ohio PUC LEXIS 543, *15-16 (May 4, 2011) (rejecting an application for rehearing that "raised nothing new"); *City of Reynoldsburg v. Columbus Southern Power Co.*, Case No. 08-846-EL-CSS, 2011 Ohio PUC LEXIS 680, *19-20 (June 1, 2011) (holding that no grounds for rehearing existed where no new arguments had been raised); *In the Matter of the Application of Columbia Gas of Ohio, Inc., for Approval of a General Exemption of Certain Natural Gas Commodity Sales Services or Ancillary Services*, No. 08-1344-GA-EXM, 2011 Ohio PUC LEXIS 1184, *9-10 (Nov. 1, 2011) (denying application for rehearing because applicant "raised nothing new on rehearing that was not thoroughly considered" in the Commission order at issue).

[26] Given the numerous repetitive arguments made by the parties filing applications for rehearing, the Companies have not here attempted to address every argument restated by these parties in their applications. Instead, to the extent that the Companies have not addressed an argument in the applications for rehearing, which merely repeats arguments previously made, the Companies incorporate their prior briefs as part of this Memorandum.

Order properly found, Stipulated ESP IV was the product of serious bargaining between diverse, knowledgeable parties who were represented by experienced counsel. As addressed below, intervenors' erstwhile objections to the contrary fall flat.

The Commission correctly found in its Order, based on record evidence, that Stipulated ESP IV met the serious-bargaining prong:

> The Commission finds that the Stipulations, as supplemented, appear to be the product of serious bargaining among capable, knowledgeable parties. We note that the signatory parties routinely participate in complex Commission proceedings and that counsel for the signatory parties have extensive experience practicing before the Commission in utility matters (Co. Ex. 155 at 2-3, 7-8). The signatory parties represent diverse interests including the Companies, a municipality, competitive suppliers, commercial customers, industrial consumers, labor unions, small businesses, advocates for low and moderate income residential customers, and Staff (*Id*. at 8).[27]

The above intervenors' attempts to undermine this amply supported finding fall into four categories of claims: (1) serious bargaining could not have occurred because a significant number of intervenors opposed Stipulated ESP IV; (2) the Signatory Parties engaged in alleged "favor-trading"; (3) the Competitive Market Enhancement Agreement ("Enhancement Agreement") negotiated between the Companies and IGS undermined serious bargaining; and (4) in the Order the Commission "created" a "new standard" for the serious-bargaining prong. Notably, the first three of these claims have already been considered and rejected by the Commission and thus should be dismissed on that basis alone.[28] In any event, even when rehashed, such arguments still fail. The Commission thus should deny rehearing on each of these issues.

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[27] Order, p. 43.

[28] *See* Order, p. 43 (reaffirming rejection of "veto power" of a party or class of customers in contested stipulations); *id*., p. 44 (considering and rejecting favor-trading allegations and side-deal argument).

B. Opposition by Some Intervenors To Stipulated ESP IV Does Not Undermine Serious Bargaining.

EPSA, RESA, NOPEC, P4S and OMAEG all claim, in one form or another, that serious bargaining could not have occurred because there was significant opposition by some intervenors to Stipulated ESP IV.[29] This argument turns on the irrelevant assertion that more parties to this proceeding opposed Stipulated ESP IV than supported them.[30] What matters, of course, is adequate diversity among the parties to a stipulation, not the raw numbers for or against.[31] Given that the Commission found that "the Stipulations are supported by a diverse group of customers, including small businesses, independent colleges and universities, industrial customers, and commercial customers as well as advocates for low- and moderate-income residential customers and Staff,"[32] this argument falls flat.[33]

Moreover, in advancing such an argument, each of these intervenors apparently believe that it should have "veto power" over any stipulation that it chooses not to sign. Any such belief

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[29] EPSA AFR, pp. 35-38, RESA AFR, pp. 38-41; NOPEC AFR, p. 9; P4S AFR, pp. 3-4; OMAEG AFR, pp. 8-12.

[30] EPSA AFR, pp. 35-36.

[31] *See 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 *55 (July 18, 2012) (approving contested stipulation because "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"); *In the Matter of the Application of Ohio Power Company to Establish Initial Storm Damage Recovery Rider Rates*, Case No. 12-3255-EL-RDR, 2014 Ohio PUC LEXIS 83, Opinion and Order (April 2, 2014) (approving contested stipulation because sufficient diversity of interests amongst the signatory parties).

[32] Order, p. 43.

[33] Indeed, given the magnitude of the instant matter, the Commission cogently observed: "We do not dispute that non-signatory parties also represent a diverse group of interests or that the diverse interests of the signatory parties and non-signatory parties sometimes overlap. However, it is not unusual in Commission proceedings for non-signatory parties to a stipulation to represent a diverse group of interests, especially in a case which has over 40 intervening parties, but that fact has little weight in our decision." Order, p. 43. On a related note, and in the absence of any supporting authority, RESA claims that the Commission should have used a "summary judgment" standard due to opposition to the Stipulations by various intervenors. RESA AFR, pp. 40-41. Given that the three-pronged test is, to say the least, well established, and that the Commission has never employed the summary judgment standard to evaluate a stipulation, RESA's argument is baseless.

flies in the face of Commission precedent. Indeed, the Commission repeatedly has found that it will not let any party, or customer class, exercise such power over a stipulation.[34] In line with this settled Commission authority, the Commission reiterated the same finding here: "we have already rejected proposals that any one class of customers can effectively veto a stipulation, holding that we will not require any single party…to agree to a stipulation in order to meet the first prong of the three-prong test."[35] Thus, this claim is meritless and rehearing should be denied accordingly.

C. Stipulated ESP IV Did Not Result From Alleged "Favor Trading."

RESA, OMAEG, EPSA, and OCC/NOAC all complain that Stipulated ESP IV was the result of alleged "favor trading" and, therefore, "proper" serious bargaining must not have occurred.[36] Clearly, if there were "favor trading," these intervenors are forced to admit that bargaining did in fact occur, albeit not to their apparent liking in light of the results. In previously rejecting this argument, the Commission reasonably found: "while many signatory parties receive benefits under the Stipulations, we will not conclude that these benefits are the

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[34] *See, e.g.*, *In the Matter of the Application of Columbia Gas of Ohio, Inc., for Approval of Tariffs to Recover, Through an Automatic Adjustment Clause, Costs Associated with the Establishment of an Infrastructure Replacement Program*, Case No. 07-478-GA-UNC, Opinion and Order at 32 (April 9, 2008) ("No one possesses a veto over stipulations, as this Commission has noted many times. Additionally, those … who ultimately became signatories to the amended stipulation represent diverse interests…"); *In The Matter of the Application of Duke Energy Ohio, Inc., to Adjust and Set its System Reliability Tracker Market Price*, Case No. 05-724-EL-UNC, Opinion and Order at 27 (Nov. 20, 2007) ("Lack of agreement by two parties should not cause the entire stipulation to be rejected as if serious bargaining had not occurred. To do so would be to give those parties, in effect, veto power over the result."); *In the Matter of the Regulation of the Purchased Gas Adjustment Clause Contained Within the Rate Schedules of The East Ohio Gas Company d/b/a Dominion East Ohio and Related Matters*, Case No. 05-219-GA-GCR, 2007 Ohio PUC LEXIS 95 at *51-54 (Jan. 31, 2007) (finding that "the settlement process clearly involved serious bargaining by knowledgeable, capable parties" even though OCC and Citizen's Coalition opposed the stipulation and claimed that residential interests were not adequately represented); *In the Matter of the Complaint of Dominion Retail, Inc. v. The Dayton Power and Light Company*, Case No. 03-2405-EL-CSS, 2005 Ohio PUC LEXIS 43 at *42-43 (Feb. 2, 2005) (rejecting argument by OCC that its approval was necessary for serious bargaining to be found to have occurred).

[35] Order, p. 43.

[36] OMAEG AFR, pp. 63-65; RESA AFR, pp. 30-36; 42-43; EPSA AFR, pp. 26-33; OCC/NOAC AFR, p. 4.

sole motivation of any party in supporting the Stipulations. We expect that parties to a stipulation will bargain in support of their own interests in deciding whether to support a stipulation."[37]

Indeed, bargaining, by its very nature, requires a *quid pro quo*. A party to a bargain gives something up in order to get something it wants in return. A rational bargainer thus gives to get. Intervenors' "favor-trading" argument, if accepted, would undermine the possibility of any rational bargaining and require parties to stipulations to be selfless and disinterested. This is an impossible standard to meet. Intervenors can cite to no authority to support such a proposition because there is none. The imposition of such an onerous standard would result in no stipulations ever being approved by the Commission. Thus, this argument (once again) warrants rejection.

D. The Enhancement Agreement Did Not Undermine Serious Bargaining.

OMAEG, EPSA and RESA all take issue (again) with the Enhancement Agreement that the Companies negotiated with IGS.[38] EPSA, for example, asserts (in the absence of any record support) that "side deals bought off any opposition to the Stipulation."[39] As the Commission correctly found in the order, "[t]he sole question for us under the first prong of our test for the consideration of stipulations with respect to the Agreement between IGS and the Companies is whether the Agreement was fully disclosed as required by R.C. 4928.145, and the record demonstrates that the parties fully complied with that statutory requirement."[40]

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[37] Order, p. 44.

[38] OMAEG AFR, pp. 8-12; RESA AFR, pp. 36-38; EPSA AFR, pp. 33-35.

[39] EPSA AFR, p. 33.

[40] Order, p. 45.

Indeed, the Enhancement Agreement was disclosed almost immediately upon execution, as the intervenors concede.[41] Specifically, the Enhancement Agreement was provided to the parties on January 14, 2016.[42] IGS's signature to the Third Supplemental Stipulation was officially docketed the following day.[43] Further, all parties were provided an opportunity to review the agreement and then to cross-examine Company witness Mikkelsen on January 15, 2016. The Attorney Examiner further afforded various parties that had concluded cross-examination of Ms. Mikkelsen the previous day, including RESA, with yet another opportunity to question her concerning any issues related to the Enhancement Agreement.[44]

Once again, intervenors seek, without success, to rely on *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 111 Ohio St. 3d 300, 321 (2006), to stand for the proposition that such agreements "provid[e] unfair advantage in the bargaining process."[45] This case is not on point. As the Commission correctly surmised in the Order: "in *Consumers' Counsel*, the side agreement was between signatory parties and the side agreement *was requested but not provided in discovery*. *Consumers' Counsel* at ¶ 86. In this proceeding, the Agreement was provided to all of the parties as a supplement to discovery (OMAEG Ex. 24)."[46] Thus, intervenors' reliance on *Consumers' Counsel* is misplaced.[47] Rehearing on this issue should be denied.

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

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

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

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

[45] EPSA AFR, p. 34.

[46] Order, p. 44 (emphasis added).

[47] Intervenors again seek to rely on *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). But the Commission's decision in that case depended upon the existence of

E. In the Order, The Commission Did Not Create A New Standard for the Serious Bargaining Prong.

OCC/NOAC claim that the Commission's Order somehow adopted a new standard for the approval of stipulations because the word "appear" is contained in the following sentence from the Order: "The Commission finds that the Stipulations, as supplemented, *appear* to be the product of serious bargaining among capable, knowledgeable parties."[48] OCC/NOAC claim that the word "is" should have been used instead of the word "appear" and, therefore, a new stipulation standard has been "created."[49] This mischaracterization of the Order ignores the Order's plain language. The word "appear" is contained in the introductory sentence in the section of the Order where the Commission lists specific findings of fact evincing that serious bargaining occurred.[50] These specific findings include, for example, that the parties to Stipulated ESP IV were *in fact* represented by experienced counsel and that the Signatory Parties did *in fact* represent a diverse group of interests and customer classes.[51] Thus, the Commission's Order did not create a "new standard" for stipulation approval as related to the serious bargaining prong merely by employing the word "appear" as opposed to the word "is." The Commission should deny rehearing on this claim.

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undisclosed side agreements, in which several signatory parties had privately agreed to support the stipulation, which "raise[d] serious doubts about the integrity and openness of the negotiation process[.]" *CG&E* at *462. This decision obviously has no applicability here.

[48] Order, p. 43 (emphasis added).

[49] OCC/NOAC AFR, p. 6.

[50] Order, p. 43.

[51] Order, p. 43.

III. THE COMMISSION PROPERLY FOUND THAT STIPULATED ESP IV BENEFITS CUSTOMERS AND IS IN THE PUBLIC INTEREST.

A. The Commission Correctly Analyzed Stipulated ESP IV As A "Package" For Purposes Of Applying The Commission's Three-Prong Test For Evaluating Stipulations.

EPSA argues that the Commission erred by analyzing Stipulated ESP IV as a "package" when it evaluated them pursuant to the second prong of the three-prong test.[52] EPSA's argument, however, is inconsistent with well-settled Ohio Supreme Court and Commission precedent. The Ohio Supreme Court has endorsed the Commission's three-prong test, which specifically requires the Commission to analyze stipulations as a "package," as an appropriate way "to resolve its cases in a method economical to ratepayers and public utilities."[53] The Commission's analysis of the Stipulation followed this test.[54] Indeed, the Commission explained that its evaluation of the Stipulation as a "package" was consistent with its prior decisions and served "as an efficient and cost-effective means of bringing issues before the Commission while also, often times, avoiding the considerable time and expense associated with the litigation of a fully-contested case."[55] EPSA fails to show any error with the Commission's application of its long-standing test. Further, EPSA fails to cite any authority in support of its claim, presumably because there is none. Thus, the Commission should deny rehearing on this issue.

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[52] EPSA AFR, p. 38-39.

[53] *Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio St. 3d 123, 126 (Ohio 1992); *accord Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.*, 68 Ohio St. 3d 559, 561-62 (Ohio 1994) (noting that the court endorsed the three-part test).

[54] Order, p. 79.

[55] Order, p. 79 (citing *In re Ohio Power Co.*, Case No. 94-996-EL-AIR, et al. Opinion and Order (Mar. 23, 1995) at 20-21; *In re Columbus Southern Power Co. and Ohio Power Co.*, Case No. 99-1729-EL-ETP, et al., Opinion and Order (Sept. 28, 2000) at 44; *In re Dayton Power & Light Co.*, Case No. 02-2779-EL-ATA, Opinion and Order (Sept. 2, 2003) at 29; AEP ESP III Order at 42; *In re Columbus Southern Power Co. and Ohio Power Co.*, Case No. 11-5568-EL-POR, et. al., Opinion and Order (Mar. 21. 2012) at 17).

B. The Commission Appropriately Determined That Rider RRS Will Provide A Substantial Stability Benefit To Customers.

In the Order, the Commission recognized the task before it regarding the competing projections of future energy, capacity, and natural gas prices presented for its review and consideration in this matter with respect to the projected amount of Rider RRS's stability benefit:

> The challenge before the Commission is to determine which projections are sufficiently reliable and how to harmonize the varying results of the projections which the Commission determines to be reliable. We note at the outset that projections and forecasts are predictions. They are predictions of future conditions and are based upon what is happening now and multiple additional assumptions. Considering the nature of the proposed Rider RRS as a potential hedge or insurance on electricity rates, in making its determination the Commission must choose from the most reliable of these projections and forecasts to make a determination of whether the Stipulations, as a package, benefit ratepayers.[56]

Faced with this evidentiary challenge, the Commission correctly found that the Companies' forecasts were the only reliable and *bona fide* projections in this proceeding aside from OCC/NOPEC witness Wilson's first scenario, which was based upon the 2014 EIA AEO Reference Case ("Scenario 1").[57] The Commission began by noting Mr. Rose's obvious qualifications and the fact that the Energy Information Agency ("EIA") regularly uses public projections from Mr. Rose's firm, ICF International ("ICF"), as benchmarks in the EIA's Annual Energy Outlook ("EIA AEO").[58] The Commission then detailed its many, well-supported findings regarding the Companies' projections:

> The only full projection of energy prices, as well as the net revenues to be recovered or credited under Rider RRS, was produced by FirstEnergy witnesses Rose and Lisowski. Mr. Rose

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[56] Order, p. 80.

[57] As discussed below, though Mr. Wilson's use of the 2014 EIA AEO was flawed, the report itself rests on a "sound forecasting methodology" – unlike the other intervenor projections proffered in this proceeding. Order, p. 84.

[58] Order, p. 80.

> prepared the projection of energy prices, while Mr. Lisowski used such prices to determine the net annual revenues to be recovered or credited under Rider RRS using the Companies' dispatch modeling. The Commission notes that Mr. Rose forecasts higher energy prices in the future, based upon a number of factors, including higher forecast natural gas prices; greater reliance on natural gas as the price setting fuel; greater reliance on more costly units as demand grows and units retire; growth in demand for electricity; power plant retirements; new environmental regulations; new FERC policies; inflation; and carbon emission regulations (Co. Ex. 7 at 5-6. 19-20; Tr. Vol. VI at 1287-88). Likewise, Mr. Rose forecasts higher capacity prices in the future based upon: elimination of excess capacity due to plant retirements; demand growth; less capacity price suppression from demand response; less capacity imports from other regions; environmental regulations, rising financing and other capital costs; inflation; and greater natural gas infrastructure leading to higher costs as gas is shipped elsewhere (Co. Ex. 17 at 6-9, 41-43). According to the Companies' forecasts, the projected net revenues to be charged or credited to customers will result in an aggregate $561 million credit (in nominal dollars) over the eight-year term of ESP IV (Co. Ex. 155 at 11-12)…. Although we are mindful of the fact that FirstEnergy has the burden of proof in this proceeding, no other party has presented a full projection of energy prices and the net revenues under Rider RRS…. Accordingly, based upon the evidence in the record, the Commission finds that this projection by FirstEnergy witness Rose (Rose projection) is reliable, and we will include the Rose projection in our determination of an estimate of the net revenues under Rider RRS.[59]

[59] Order, pp. 80-82. Cleveland Metropolitan Schools District ("CMSD") contends that evidence of credits for the years four through eight of Rider RRS are "speculative." CMSD AFR, p. 16. CMSD fails to grasp the difference between speculation and a sophisticated, methodologically sound forecast. The Commission's Order, however, recognizes the difference. As the Commission correctly observes, the key is to choose the most reliable forecast, which, in selecting the Companies' methodologically sound forecasts, the Commission in fact did. Moreover, both RESA and EPSA complain that the Order fails to cite "specific findings of fact, supported by the record, and the reasons for the Commission's decision to adopt Mr. Lisowski's calculations of the projected charges and credits under Rider RRS" in alleged violation of R.C. 4903.09 of the Ohio Revised Code. RESA AFR, p. 52; EPSA AFR, p. 48. RESA and EPSA, however, overstate their case and rely on a much too narrow construction of R.C. 4903.09. As the Supreme Court of Ohio has observed at length:

> Taken literally, R.C. 4903.09 requires PUCO orders to contain specific findings of fact and conclusions of law. However, the requirements of R.C. 4903.09 have been satisfied by orders which incorporate or adopt attorney-examiner reports or commission secretary reports which contain such findings or conclusions…. Furthermore, PUCO orders which incorporate testimony from the proceeding or incorporate the entire record from a related investigative PUCO case have been upheld as reasonable and lawful…. *In fact, where there was enough evidence and discussion in an order to enable the PUCO's reasoning to be readily discerned,*

Numerous intervenors, including Sierra Club, OCC/NOAC, EPSA, RESA, and OMAEG, challenge the Commission's findings. They further contend that the Commission instead should have relied on partial projections and selective observations by their witnesses. To the contrary, the Commission's findings regarding the Companies' forecasts are amply supported by the record, and the Commission was further correct to find that intervenors' rival projections were methodologically flawed and warranted rejection. As demonstrated below, intervenors' arguments to the contrary are meritless. The Commission should deny rehearing on these issues accordingly.

1. The Commission was correct to rely on the Companies' forecasts.

Various intervenors, such as Sierra Club, OCC/NOAC, RESA and EPSA, all complain that the Commission should not have relied upon Mr. Rose's forecasts, claiming, among other things, that these forecasts are "stale" and "outdated."[60] Sierra Club, for example, argues that Mr. Rose's projections for natural gas prices, market energy prices, and capacity prices are outdated.[61] OCC/NOAC concur.[62] RESA and EPSA make a similar claim regarding Mr. Rose's

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> *this court has found substantial compliance with R.C. 4903.09,* and held that the lack of specific findings may be simply a technical defect which would not result in the invalidation of the order.

MCI Telecommunications Corp. v. Pub. Util. Comm., 32 Ohio St. 3d 306, 311-312 (1987) (emphasis added) (citations omitted). In light of the Commission's listing of specific findings of fact in the record related to the reliability and soundness of Mr. Rose's forecasts, and the tight relationship between Mr. Lisowski's forecasts to Mr. Rose's, there is more than an enough evidence here "to enable the PUCO's reasoning to be readily discerned." At the very minimum, the Commission has substantially complied with the requirements of R.C. 4903.09 on this issue. RESA and EPSA's suggestions otherwise are meritless.

[60] OCC/NOAC AFR, pp. 9;11-12; EPSA AFR, pp. 52-53; RESA AFR, p. 57; Sierra Club AFR, pp. 24-33.

[61] Sierra Club AFR, pp. 25-28.

[62] OCC/NOAC AFR, pp. 9-10.

projection for natural gas prices.[63] Notably, the Commission already considered and rejected such arguments in the Order:

> We note that several parties criticize FirstEnergy for not updating its projection since it was prepared prior to the filing of the application in this proceeding in 2014. However, the EIA noted in its Annual Energy Outlook for 2015 that the projected electricity prices for the Reference case, over the long term, actually increased in comparison to the Reference case for the Annual Energy Outlook for 2014. EIA noted that:
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>> In the AEO 2015 Reference case delivered natural gas prices to electricity generators are lower than in the AEO 2014 Reference case in the first few years of the projection but higher throughout most of the 2020s. From 2020 to 2030, the generation cost of component of end-use electricity prices is, on average, 4% higher in AEO 2015 than in AEO 2014. (Co. Ex. 166 at E-7).
>
> Therefore, it is likely that, even if Mr. Rose had updated his projection, the resulting higher electricity prices would have made Rider RRS appear to be more favorable to customers rather than less favorable.[64]

On this basis alone, rehearing should be denied.

a. Mr. Rose's forecasting methodology was sophisticated and reliable.

As the Commission found in the Order, there can be no dispute that, in arriving at his projections, Mr. Rose employed some of the most sophisticated forecasting methodology currently available. To generate his forecasts, Mr. Rose employed sophisticated computer models, including such widely recognized models as ICF's Integrated Planning Model ("IPM"), General Electric's GE-MAPS, and ICF's Gas Market Model ("GMM").[65] These sophisticated

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[63] RESA AFR, p. 57; EPSA AFR, pp. 52-53 (in accepting Mr. Rose's natural gas forecast, the Commission ignored the recent "downward price trend" in natural gas prices).

[64] Order, p. 81.

[65] Rose Rebuttal, p. 3.

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.[66]

Importantly, Mr. Rose explained the model's integrated treatment of key variables, as well as the need for forecasts to resist inappropriate reliance on near-term conditions in volatile industries:

> 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.[67]

These models enabled Mr. Rose to provide "a probability-weighted projection also referred to as an 'Expected Value' forecast, which is the key basis for decision making."[68] For instance, 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.[69] 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

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[66] Rose Rebuttal, p. 3.

[67] Rose Rebuttal, p. 7.

[68] Rose Rebuttal, p. 9. "Probability weighting incorporates uncertainty and the relative likelihood of a range of outcomes." *Id.*

[69] Rose Rebuttal, p. 10.

> 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).[70]

Such methodological sophistication definitively sets Mr. Rose's forecasts apart from the "forecasts" – in actuality nothing more than unsophisticated predictions – proffered by OCC/NOPEC witness Wilson, EPSA witness Kalt, and Sierra Club witness Comings. Notwithstanding RESA's and EPSA's claims to the contrary, and as the Commission correctly found in the Order, such a solid methodological basis speaks volumes about the reliability of Mr. Rose's forecasts.[71] Indeed, Mr. Rose's sophisticated methodological approach provides the appropriate backdrop against which to evaluate intervenors' rehashed claims that Mr. Rose's forecasts are stale or outdated and, further, that the Commission somehow erred (which it clearly did not) in relying upon them.[72]

b. The Commission was correct to rely on Mr. Rose's natural gas price and energy price forecasts.

Sierra Club, OCC/NOAC, RESA, and EPSA apparently view natural gas prices as the main driver of energy prices and seek to make much of the fact that natural gas prices are currently lower than Mr. Rose projected.[73] Lower than expected natural gas prices in the near term, however, are of no moment, given the extreme volatility of natural gas and the current state of gas market fundamentals. Moreover, intervenors fail to grasp that natural gas prices and energy prices do not move in lockstep, particularly in Ohio where coal regularly sets the margin.

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[70] Rose Rebuttal, p. 10.

[71] RESA AFR, pp. 50-51; EPSA AFR, pp. 40-41; Order, pp. 80-81.

[72] As the Companies demonstrated at length in their Reply Brief, Mr. Lisowski employed a sophisticated computer model that was proprietary to FES, as well as inputs from Mr. Rose. *See* Companies' Post Hearing Reply Brief, pp. 61-63.

[73] OCC/NOAC AFR, pp. 9, 11-12; EPSA AFR, pp. 52-53; RESA AFR, p. 57; Sierra Club AFR, pp. 24-33.

As such, intervenors' previously raised and rejected claims that Mr. Rose's natural gas and energy projections are stale or outdated simply miss the mark.

To begin, these intervenors continue to ignore the extreme volatility of natural gas. As the record undeniably demonstrates, natural gas is perhaps the most volatile of all commodities. Mr. Rose testified to this fact extensively, and his testimony was uncontroverted by intervenor testimony or cross-examination at hearing. In his rebuttal testimony, Mr. Rose explained in detail why lower short-term natural gas prices are neither surprising nor impactful on his long-term forecast:

> 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.[74]

Indeed, various intervenor witnesses conceded at hearing the volatile nature of natural gas prices, particularly in the short term. For example, Dr. Kalt admitted that from December 16, 2015, to December 29, 2015, Henry Hub futures were 33 cents higher for 2016[75] and 14

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

[75] Hearing Tr. Vol. XLI, pp. 8672-8673 (Kalt Cross).

cents higher for 2017[76] – a substantial percentage increase in a very short period of time.[77] Likewise, 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,[78] going from a low of $1.54 on December 24, 2015, to a high of $2.35 on January 6, 2016.[79] Moreover, Mr. Wilson admitted that the low prices experienced in December 2015 should be considered *a very short-term condition*.[80]

Such near-term volatility, however, has a very limited impact on Mr. Rose's long-term natural gas projections. 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?
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> 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*,

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

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

[78] Hearing Tr. Vol. XXXIX, p. 8289 (Comings Cross).

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

[80] Hearing Tr. Vol. XXVIII, p. 8121 (Wilson Cross). Further, OCC/NOAC's suggestion that the Commission should have relied on the January 2016 EIA Short-Term Energy Outlook misses the mark. OCC AFR, p. 11. Given that it is, by definition, a "short-term outlook," the Commission acted correctly in utilizing the 2015 EIA AEO – a much more comprehensive report that focuses on long-term forecasts.

> and it would bring my number approximately down to the EIA number if I adopted the most recent gas prices.[81]

Thus, given the extreme volatility of natural gas, short-term natural gas prices gleaned on any particular day cannot be used to properly evaluate a long-term, methodologically sound natural gas forecast such as Mr. Rose's. In the Order, the Commission correctly concurred.[82]

Sierra Club once again complains that ICF's other more recently published natural gas forecasts are lower than what Mr. Rose forecasted here.[83] This argument has no more traction now than when it was first raised in Sierra Club's initial post-hearing briefing.[84] Specifically, Sierra Club points to what it claims is an August 2015 ICF publication and notes that ICF's forecast then showed that gas prices rise at a slower level than what Mr. Rose forecasted here.[85] Again, Sierra Club's discussion is misleading. Notably, 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.[86] 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.[87] 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

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

[82] Order, p. 81.

[83] *See* Sierra Club AFR, p. 30.

[84] *See* Sierra Club Initial Brief, p. 25 and Reply Brief, pp. 25-26.

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

[86] *See id.*, p. 4.

[87] *See id.*, p. 18.

2025).[88] Indeed, the report's forecast for LNG exports (one potential driver of natural gas demand) is higher than Mr. Rose's forecast here.[89] Thus, the two forecasts are quite compatible.

Contrary to the claims of these intervenors, natural gas market fundamentals indicate that gas prices have nowhere to go but up. As the Companies previously argued, and as shown in the record, the fundamentals in the natural gas market show that natural gas supply is decreasing and natural gas demand is increasing.[90] Hence, natural gas prices should be expected to increase over the long term precisely in line with Mr. Rose's forecasts.[91] Accounting for near-term volatility, Mr. Rose's long-term gas forecasts are on target, and the Commission was right to rely on them. Indeed, as the Commission astutely noted, Mr. Rose is not alone here: the 2015 EIA AEO, clearly a methodologically sound forecast along the lines of Mr. Rose's, projected higher long-term natural gas prices throughout the 2020s.[92] Thus, intervenors' putative claims that Mr. Rose's natural gas forecasts are outdated or stale fall flat.

Further, Sierra Club and the other intervenors once again simply miss the point that natural gas prices and energy prices do not move in lockstep.[93] This is especially true in Ohio where coal regularly sets the margin. 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:

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[88] *See id*., p. 8.

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

[90] Rose Rebuttal, pp. 31-42; Companies' Post Hearing Reply Brief, pp. 38-40.

[91] Rose Rebuttal, pp. 33, 36-37; Companies' Post Hearing Reply Brief, pp. 38-40.

[92] Order, p. 81. Sierra Club goes so far as to claim that the Commission "cherry-picks" the 2015 EIA AEO. *See* Sierra Club AFR, p. 31. Sierra Club then goes on to claim that the January 2016 EIA AEO has "revised downward at least its short term natural gas price forecast." Sierra Club AFR, p. 33. As noted, however, given the volatility of natural gas, short-term swings in price warrant little attention from a long-term perspective such as the one at issue here.

[93] Sierra Club AFR, pp. 32-33; EPSA AFR, pp. 52-53.

> [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.[94]

As Mr. Rose further testified at the hearing, recent decreases in natural gas prices have had but 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.[95]

Thus, given the moderate effect of near-term natural gas prices on long-term electrical energy prices, the putative claims by Sierra Club, EPSA, RESA and OCC/NOAC regarding Mr. Rose's natural gas forecasts are even more suspect. In the Order, the Commission rightly rejected such claims. The Commission should deny rehearing accordingly.

c. The Commission was correct to rely on Mr. Rose's capacity price forecasts.

RESA, EPSA and Sierra Club claim that the Commission erred in the Order by relying on Mr. Rose's capacity price forecasts.[96] However, as the record demonstrates, Mr. Rose's capacity forecasts have held up quite well, and the Commission was correct to rely on them.

By any measure, Mr. Rose's capacity price forecast has performed quite well:

- On August 10, 2015, the 2018/2019 PJM Base Residual Auction (BRA) Capacity Performance ("CP") capacity price increased from \$120/MW-day to \$165/MW-day (+38%); \$165/MW-day was the second highest RTO capacity price.[97]

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[94] Rose Rebuttal, p. 13.

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

[96] RESA AFR, pp. 49-52; EPSA AFR, pp. 45-47; Sierra Club AFR, pp. 21, 27.

[97] Rose Rebuttal, p. 21.

- On August 27, 2015, the PJM incremental transition auction for 2016/2017 procurement increased the RTO CP capacity price from $60/MW-day to $134/MW-day (+123%).[98]

- 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/MW-day to $152/MW-day (+27%).[99]

Indeed, the record evidence suggests that capacity prices will increase even more as the CP requirements come into effect. For instance, capacity prices are nearing offer caps in certain zones within PJM:

- 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.[100]

- 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 BRA (+88%). This price was 99% of the bid cap, and hence, is evidence that PJM capacity prices can reach the offer price cap.[101]

At hearing, Mr. Rose testified to the similarities between the impacts of PJM's recently adopted CP requirements 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.[102]

In line with Mr. Rose's forecast, capacity prices have increased significantly across the board, in PJM as a whole, and in various sub-zones.

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[98] Rose Rebuttal, p. 21.

[99] Rose Rebuttal, p. 22.

[100] Rose Rebuttal, p. 22.

[101] Rose Rebuttal, p. 22.

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

Sierra Club again levels the baseless claim that Mr. Rose overstated anticipated capacity prices for the 2018/2019 BRA auction: "while Mr. Rose projected that capacity prices would spike to [**BEGIN CONFIDENTIAL]** [redacted] [**END CONFIDENTIAL]** for the 2018/2019 base residual auction, the actual clearing price for capacity performance products in that auction was $164.77/MW-day."[103]

As the Companies demonstrated at length in their Reply Brief, this baseless criticism is belied by the record evidence.[104] The difference in these figures is of little significance and by no means impugns Mr. Rose's capacity price forecast. It merely shows that Mr. Rose was off about the timetable for PJM to transition to full CP requirements, but, significantly, he was not off about the effects of those requirements. Specifically, in 2015, PJM published its "Scenario Analysis for the 2018/2019 BRA."[105] Scenario 13 of that report showed 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 – roughly $70 higher per MW-day than what actually occurred.[106] As such, Mr. Rose's capacity forecast regarding the *effect* of full CP requirements was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Indeed, PJM's forecast under Scenario No. 13 is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than Mr. Rose's forecast with a full CP requirement.

Further, by Sierra Club witness Comings's own measure, any variance between Mr. Rose's capacity price forecasts and those of PJM was insignificant. As Mr. Comings admitted at

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[103] Sierra Club AFR, p. 27.

[104] *See* Companies' Post Hearing Reply Brief, pp. 55-56.

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

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

hearing, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from one another.[107] In Table 6 of its Initial 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%.[108] Given the above, these rehashed criticisms of Mr. Rose's capacity price forecast are meritless, and rehearing on this issue should be denied accordingly.

2. The Intervenor forecasts were correctly weighted by the Commission.

a. The Commission properly rejected OCC/NOPEC witness Wilson's second and third scenarios.

In the Order, the Commission properly found that two of the "forecasts" by OCC/NOPEC witness Wilson were "fundamentally flawed": Mr. Wilson's second scenario ("Scenario 2"), which relied on the 2014 and 2015 EIA AEO High Oil and Gas Resource case; and Mr. Wilson's third scenario ("Scenario 3"), based on NYMEX futures.[109] This assessment is correct on all counts, and rehearing is not warranted here.

Regarding Scenario 2, the Commission correctly found Mr. Wilson's forecast was unreliable because of his selective use of EIA projections, especially without necessary corresponding adjustments to generation costs:

> Although Mr. Wilson changed the price of natural gas in FirstEnergy witness Rose's forecast to the price predicted by the EIA in the High Oil and Gas Resource case and changed the price of electricity to reflect that price of natural gas, Mr. Wilson failed to change all of the interrelated variables in FirstEnergy witness Rose's forecast and FirstEnergy witness Lisowski's model…. The net effect of Mr. Wilson's selective use of the EIA's projected natural gas and coal prices is to suppress the revenue from the sale

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

[108] Sierra Club Initial Post Hearing Brief, p. 36.

[109] Order, p. 82.

> of electricity under Rider RRS because of low forecasted electricity prices while keeping the costs of generating such electricity constant by failing to modify the assumed coal prices. This inconsistent application of related variables artificially suppresses projections of the net revenue recovered or credited under Rider RRS.
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> The next flaw in OCC witness Wilson's second projection is that Mr. Wilson arbitrarily chose to use the High Oil and Gas Resource case out of the numerous other cases prepared by the EIA for both the 2014 and the 2015 Annual Energy Outlook. The Commission notes that, at the time of the hearings in this proceeding, the price of natural gas was near historic lows…. [T]he claims by OCC and NOPEC, and other intervenors relying upon Mr. Wilson's testimony, that Rider RRS will cost consumers $2.7 billion rely upon a projection which assumes that the price of natural gas, electricity and oil will remain below 2013 prices (in 2013 dollars) for at least the next 15 years.
>
> The Commission does not believe that the evidence supports OCC and NOPEC's prediction that we have entered a period of energy price utopia where the price of natural gas, electricity and oil remains flat for a period of 15 years nor do we believe it would be responsible for the Commission to base its decision on such a prediction.[110]

Regarding Scenario 3, the Commission correctly found that it also is unsupported and unreliable because it arbitrarily assumes that natural gas prices will remain flat:

> [T]he evidence in the record demonstrates that forward markets beyond three years are thinly traded and that forward market prices beyond three years do not necessarily reflect actual transactions but reflect offers which may or may not have been accepted instead (Co. Ex. 151 at 49-50). Mr. Wilson addresses this issue by simply predicting that natural gas prices will rise by the rate of inflation in the out years (OCC/NOPEC Ex. 9 at 7; Tr. Vol. XXII 4571). We note that, by simply adjusting the forward prices for inflation, Mr. Wilson is once again predicting that natural gas prices will remain flat, in real dollars, in the future (Tr. Vol. XXII at 4571). However, Mr. Wilson presents no testimony regarding this projection as to why natural gas prices will remain flat in real dollars. Instead, Mr. Wilson defends this forecast as the most reliable based upon current market data (OCC Ex. 9 at 10).

[110] Order, pp. 82-83.

> However, the current market data Mr. Wilson relies upon are very short term prices which were heavily influenced by warm weather conditions (Tr. Vol. XXXVIII at 8119-21; Co. Ex. 167 at 10).[111]

These findings are well supported by the record, and various intervenors' protests to the contrary are baseless.[112] Thus, these "projections" warrant summary dismissal. Requests for rehearing on this issue should be denied.

(i) Mr. Wilson's Scenario 2 was contradicted by the record evidence.

Regarding Scenario 2, as demonstrated at hearing, the reason Mr. Wilson chose to include the High Oil and Gas Resource Case was because he could, in result-oriented fashion, use it to show that Mr. Rose's projection of natural gas prices was allegedly too high. This then enabled Mr. Wilson to develop a large cost number for Rider RRS. As explained by Mr. Rose, the High Oil and Gas Resource Case is one out of a total of twenty-one alternative scenarios to which the Reference Cases may be compared.[113] Conveniently for Mr. Wilson, the High Oil and Gas Resource Case also just happens to be a case with forecasted natural gas prices that are significantly lower than the Reference Cases. As Mr. Rose observed, "EIA's 2014 High Oil and Gas Resource Case is 17.4% lower on average for 2015 to 2031 than the 2014 Reference Case."[114]

Mr. Wilson admitted under cross-examination that the High Oil and Gas Resource Case was the lowest case for "most years" – out of the five cases projecting natural gas prices in the 2014 EIA AEO.[115] Indeed, Mr. Wilson additionally admitted that "in most years, it's the lowest

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[111] Order, p. 84.

[112] *See* OCC/NOAC AFR, p. 12; OMAEG AFR, p. 13.

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

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

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

by a lot."[116] Mr. Wilson further admitted that the High Oil and Gas Resource Case assumes higher levels of oil and gas production.[117] He also agreed, upon reviewing the relevant portions of the 2014 AEO, that "[t]here is uncertainty for sure, yes" regarding the projection of oil and gas production.[118]

At hearing, Mr. Wilson made a series of telling admissions to the Attorney Examiner. Mr. Wilson admitted that the 2015 High Oil and Gas Resource Case: (1) had the lowest projected prices for natural gas of any other forecast;[119] (2) projected natural gas at less than $4.00 per MMBtu through 2025;[120] (3) had the next lowest prices for coal;[121] and (4) had the lowest of all electricity prices.[122] Mr. Wilson admitted that none of the assumptions underlying the 2015 High Oil and Gas Resource Case are supported by evidence in the record.[123] Given the above, the Commission properly rejected Scenario 2.

(ii) Mr. Wilson's Scenario 3 was contradicted by the record evidence.

Intervenors also cannot rehabilitate Scenario 3, *i.e.*, NYMEX futures. The record demonstrates that employing 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.*, it 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 natural gas futures prices

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

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

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

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

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

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

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

[123] Hearing Tr. Vol. XXXVIII, p. 8157-58 (Wilson Cross).

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 what long-term natural gas prices will in fact be.

The record shows that natural gas futures are only useful for short-term forecasting due to the extreme illiquidity of the natural gas futures market after two years.[124] Indeed, the record is replete with intervenor admissions in this vein. Mr. Wilson 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."[125] OCC/NOPEC witness Kahal, after admitting that Mr. Wilson's third scenario is based upon natural gas futures prices,[126] further admitted that forecasts do not use future prices beyond the first two to three years because in the outer years the futures market is thin.[127] Similarly, RESA witness Scarpignato admitted that the NYMEX natural gas futures market is generally illiquid beyond three years.[128] So did Mr. Comings[129] and Dr. Kalt.[130]

A second reason 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

[124] Rose Rebuttal, p. 49; Figure 10.

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

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

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

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

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

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

> 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) between the average futures price and the spot price on a monthly basis [from January 2007 to February 2015].[131]

Thus, attempting to extrapolate several years out from current natural gas market conditions merely reflects those current market conditions and has limited predictive efficacy. Thus, Scenario 3 was rightly rejected by the Commission in the Order.

b. The Commission properly rejected EPSA witness Kalt's analysis.

OCC/NOAC, EPSA, and RESA all claim that the Commission erred in rejecting the sensitivity analysis performed by EPSA witness Kalt.[132] These claims are meritless. In the Order, the Commission questioned Dr. Kalt's selective use of sensitivity analyses:

> Dr. Kalt demonstrates in his sensitivity analysis that holding all other variables constant, if natural gas prices stay at current, historic low levels, it will substantially increase the costs to be recovered under Rider RRS. However, we are skeptical that all other variables will remain constant. The evidence in the record is that the prices of natural gas, electricity, coal, oil and other energy-related products are strongly correlated (Co. Ex. 166 at C-1 through C-12, D-1 through D-14). Thus, a sensitivity analysis solely on the price of natural gas is helpful to the extent that it demonstrates that revenues under Rider RRS will be strongly correlated to the price of natural gas, but it is of little value as a projection of the net credits or costs of Rider RRS over the eight-year term.[133]

As the record demonstrates, the Commission correctly declined to place any reliance on Dr. Kalt's analysis.

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

[132] OCC/NOAC AFR, p. 18; RESA AFR, pp. 53-57; EPSA AFR, pp. 48-52.

[133] Order, p. 85.

Like Mr. Wilson's Scenario 3, Dr. Kalt's analysis relies on futures and, thus, suffers from the same deep methodological flaws.[134] 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.[135] He further admitted that natural gas prices are extremely volatile.[136] Additionally, Dr. Kalt agreed that at three years out the market for natural gas futures is "relatively thin" and the volume of trades go down.[137] He also acknowledged that this thinness could result in a situation where a single transaction in the out years could significantly skew, in one direction or the other, the price for that futures period.[138]

Dr. Kalt attempted to overcome this market thinness by relying on NYMEX futures for the first three years of the term of Rider RRS and then following the "trend" of 2015 EIA AEO Reference Case subsequent to 2018.[139] Dr. Kalt apparently believed that the EIA would have similarly revised its 2015 AEO Reference Case to account for the decline in futures prices since publication of the 2015 AEO in April 2015. Notably, however, Dr. Kalt admitted under cross-examination that he did not compare the 2015 Reference Case to the 2014 Reference Case for natural gas prices.[140] Yet the 2015 AEO Reference Case did not show a substantial decline from the 2014 AEO Reference Case. Natural gas price projections in the 2015 Reference Case are only 1.5% lower than in the 2014 Reference Case – hardly a significant decline.[141] Further, Dr.

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[134] Notably, EPSA simply ignores and in no way attempts to defend the obviously faulty methodology employed by Dr. Kalt. *See* EPSA AFR, pp. 48-52.

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

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

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

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

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

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

[141] Rose Rebuttal, p. 45.

Kalt ignores the fact that "both EIA AEO reference cases (i.e., 2014 and 2015) are [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[142] Dr. Kalt's analysis thus lacks a sound methodological basis, and the Commission was right to reject it. No rehearing is necessary.

c. The Commission properly ignored Sierra Club witness Comings' projection.

OCC/NOAC and OMAEG complain that the Commission should have relied on the projection of Sierra Club witness Comings.[143] The Commission, however, found that Mr. Comings' projection had no significant role to play in the Commission's estimate of the anticipated credits that Rider RRS will likely provide to customers. As the record demonstrates, the Commission was correct in its assessment.

Prior to its well-reasoned decision to ignore Mr. Comings' projection, the Commission estimated that the credits likely to be provided to the Companies' customers under Rider RRS totaled $256 million:

> [I]n determining an estimate of the net revenues to be recovered or credited under Rider RRS over eight years, the Commission has found that two publically available projections are reliable: the Rose/Lisowski projection of a credit of $561 million and the Wilson projection of a charge of $50 million. We note that testimony in the hearing agreed that the Commission could aggregate projections which were found to be reliable by averaging the projection (Tr. Vol. XXII at 4384-86). Averaging a credit of $561 million and a charge of $50 million results in a reasonable estimate of a projected $255.5 million (or $256 million, rounded up) net credit to customers over the eight years of Rider RRS. Accordingly we will rely upon that estimate for purposes of this

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[142] Rose Rebuttal, p. 39.

[143] OCC/NOAC AFR, p. 19; OMAEG AFR, p. 13.

> proceeding. Thus, in approving Rider RRS today, we base our decision on these projections.[144]

The Commission explained that while Mr. Comings' projection could not be included in the Commission's estimate, if it had been include it would not have materially changed the finding of a projected net credit to customers:

> Sierra Club witness Comings also produced a projection of net charges or credits under Rider RRS (Sierra Club Ex. 96C at 2, 6). This projection is based upon confidential information obtained from FES in discovery…. As this projection is based upon confidential information, it is impossible for us to include this projection in our estimate of the net credit or charges to customers under RRS without confidential information being easily derived from the calculation. However, we will note that, *if we had included this projection in the average with the other two projections to develop our estimate, it would not change our decision in this case as there would continue to be a projected net credit to customers over the eight years of Rider RRS* (Sierra Club Ex. 96C, Co. Ex. 155 at 11, OCC/NOPEC Ex. 9 at 12).[145]

Notwithstanding the fact that the Comings projection could not be disclosed because it contained or would lead to the derivation of trade secrets belonging to FES, the Commission was still right to ignore it. As the record demonstrates, serious methodological flaws also mar the Comings projection, and, as a result, it adds nothing noteworthy to this case. Mr. Comings' projection has led Sierra Club to claim that Rider RRS [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[146] Mr. Comings, however, failed to grasp that in its projections FES was itself overly conservative. FES projected costs that were likely too high and revenues that were likely too low. Hence, Mr. Comings' projection adds nothing of evidentiary value.

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[144] Order, p. 85.

[145] Order, p. 85.

[146] Sierra Club AFR, pp. 23-24.

The FES inputs included a [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] carbon price than the forecast presented by the Companies. Notably, 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**].[147] While Mr. Comings criticized the Companies' estimate for carbon costs as being too low,[148] this criticism is clearly incorrect. The United States Supreme Court's recent stay of the CPP implementation essentially ensures the absence of a carbon price through the term of Rider RRS.[149] As the Companies indicated in their Reply Brief, 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.[150] As a result, Mr. Comings' projection understates revenues by [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] through the term of Rider RRS.[151]

Additionally, Mr. Comings' analysis conveniently ignored the recent PJM capacity auction results for planning years 2016/2017, 2017/2018 and 2018/2019. Those auctions will

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

[148] Comings Direct, p. 51.

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

[150] *See* Companies' Post Hearing Reply Brief, p. 111.

[151] Companies' Post Hearing Reply Brief, pp. 111-12.

result in [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] more revenue under Rider RRS, further increasing the already substantial benefit for customers.[152]

Thus, contrary to OCC/NOAC and OMAEG's claims, Mr. Comings' projection in no way negatively impacts Rider RRS. Hence, the Commission astutely observed that Mr. Comings' projection based upon FES inputs added nothing to the Commission's estimate of the likely credits to customers under Rider RRS. Rehearing should be denied accordingly.

d. The Commission's averaging of the Companies' forecasts with OCC/NOAC witness Wilson's first scenario was neither unlawful nor unreasonable.

RESA and Sierra Club take issue with the averaging approach the Commission adopted in the Order to estimate the likely credit of Rider RRS to customers over the term of Stipulated ESP IV.[153] RESA argues that the Commission should not have averaged "diametrically opposed projections."[154] Sierra Club contends that the Commission should have relied on Wilson Scenario 2, *i.e.*, the High Oil and Gas Resource Case, instead of Mr. Wilson's first scenario, which was based upon the 2014 EIA AEO Reference Case ("Scenario 1"). As demonstrated below, both of these claims fall flat.

RESA claims that the Commission engaged in a "rudimentary averaging" of the Companies' projection of a $561 million credit with a $50 million charge from Wilson Scenario 1.[155] RESA further claims that such an approach was inconsistent with the hearing testimony of OEG witness Baron that the Commission cites to for record support. RESA's claim is meritless

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[152] *See* Figure 5 on p. 112 of the Companies' Post Hearing Reply Brief (Lisowski Table named "Actual PJM Auction Results Compared To Filed Workpaper").

[153] RESA AFR, pp. 45; 58-59 Sierra Club AFR, pp. 33-36. *See also* EPSA AFR, pp. 53-54.

[154] RESA AFR, p. 45.

[155] RESA AFR, p. 58.

and the hearing transcript demonstrates as much. At the hearing, the following colloquy occurred between the Attorney Examiner and OEG witness Baron:

> EXAMINER PRICE: Now, you are an economist, and I am not, so I am going to ask you a question. Is it analogous with these projections, is it too crude for the Commission to take an average of these projections and say, all things considered, this is probably the most likely result?
>
> THE WITNESS: If all things were equal, that might be a reasonable answer. And, again, I haven't looked at the individual forecasts, but in the case of economic for -- market price forecasts, for example, there -- I think you have to go beyond that and sort of look at the methodology, compare them and the assumptions because if the averaging was simply the answer, then anybody could say, well, I am going to affect the average, I'll just say it's going to be this, and if that -- and a much lower forecast or a much higher forecast.
>
> And it wouldn't be reasonable if that forecast was included in the average if it didn't meet certain standards of reasonableness in terms of assumption, methodology, whatever. So as a general matter, I agree with the averaging concept, but I do think you have to go further and evaluate whether there are imperfections, sort of systematic imperfections in the methodology or the assumption or something of that nature to make sure that it's –it's qualified to be included in the average.
>
> EXAMINER PRICE: But if you made that decision, if you said, okay, we have looked at the underlying assumptions, they are within a range of reason for each individual projection, it would not be too crude a mechanism simply to average them and come up with a result?
>
> THE WITNESS: That would certainly be a way to do it, to look at it.[156]

The Commission followed Mr. Baron's recommendation. Far from a "simple averaging," the Commission reviewed each proffered projection for methodological soundness and reliability. It then chose those projections that met the mark; namely, the Companies' projection

[156] Hearing Tr. Vol. XXII 4384:16-4385:25 (Baron Cross).

and Wilson Scenario 1. The Commission then averaged the results to arrive at the $256 million estimated credit. In doing so, the Commission acted conservatively because Scenario 1 is flawed.

In Scenario 1, as the Commission correctly found, "Mr. Wilson also substitutes the energy and natural gas prices forecast by FirstEnergy witness Rose with natural gas prices forecast by the EIA and with energy prices derived from such forecasts by Mr. Wilson based upon the relationship between natural gas and energy prices."[157] Scenario 1 was based upon a "sound forecasting methodology," and, thus, the Commission determined that its "use" was "reasonable."[158] Even still:

> We note that this projection shares the same flaw as OCC witness Wilson's other projections in that he did not modify either the implied heat rates projected by FirstEnergy witnesses Rose and Lisowski or the coal prices assumed by Mr. Rose to the coal prices predicted by the Reference case. However, these flaws are somewhat mitigated by the fact that the natural gas prices predicted by the Reference case are not abnormally low as in the High Oil and Gas Resource case. Further coal prices and production projections in the Reference case are generally more in line with projections published by ICF.[159]

Thus, the Commission could have rejected Scenario 1 for these reasons as well. Nonetheless, given that Scenario 1 was "based on sound forecasting methodology" (unlike the other intervenor projections), the Commission allowed its use. Thus, RESA has nothing to complain about here.[160]

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[157] Order, p. 84.

[158] Order, p. 84.

[159] Order, p. 84.

[160] RESA and EPSA also complain that the Commission's $256 million estimate makes no allowance for the possibility of "substantial early charges" in the early years of ESP IV, and, thus, "a 'net' benefit to ratepayers is not necessarily a benefit at all." EPSA AFR, p. 57. *See also* RESA AFR, p. 61 (same). Both RESA and EPSA, however, ignore the Commission's modification to Stipulated ESP IV requiring that average customer bills are, with certain exceptions, not allowed to increase for the first two years of Stipulated ESP IV as compared to average bills

Sierra Club's suggestion – that the Company should have relied on Scenario 2 instead of Scenario 1 – is even more off base. As noted extensively above, Mr. Wilson's use of the High Oil and Gas Resource Case suffers from such deep methodological flaws that it has no place here. Sierra Club tries to justify using this deeply flawed scenario by claiming that "the High Oil and Gas Scenario is a realistic enough possibility for the EIA to model it."[161] Sierra Club, however, simply ignores, among other things, "Mr. Wilson's selective use of the EIA's projected natural gas and coal prices is to suppress the revenue from the sale of electricity under Rider RRS because of low forecasted electricity prices while keeping the costs of generating such electricity constant by failing to modify the assumed coal prices."[162] Sierra Club's argument warrants being dismissed out of hand. The Commission should deny requests for rehearing on these issues.

3. The Commission's decision to use a nominal dollar calculation was neither unreasonable nor unlawful.

Sierra Club makes the curious argument that the Commission somehow erred when it calculated the estimated value of Rider RRS credits to customers in nominal dollars as opposed to a net present value ("NPV") basis.[163] Specifically, both the Companies' projection and Wilson Scenario 1, if averaged on an NPV basis yields a "$37 million credit for rider RRS."[164] According to Sierra Club, "merely switching to NPV, while keeping all of the other assumptions used by the Commission held the same, leads to an 85.5% reduction in the $256 million

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for the period from June 1, 2015, to June 1, 2016. *See* Order, p. 86. This modification should more than allay RESA and EPSA's concerns, to the extent such concerns are even legitimate.

[161] Sierra Club AFR, p. 34.

[162] Order, p. 82.

[163] Sierra Club AFR, pp. 22-24.

[164] Sierra Club AFR, p. 24.

projected benefit of Rider RRS to customers that the Commission relies on so heavily in its Order."[165] However, Sierra Club's conversion of the benefits from nominal dollars to NPV is a meaningless exercise.

As Sierra Club itself notes, Mr. Wilson's Scenario 1 was provided in nominal dollars (a $50 million charge).[166] The Commission then consistently averaged these Scenario 1 results with the nominal dollar amount of the Companies' projection (a $561 million credit) to arrive at the $256 million likely credit in nominal dollars. In doing so, the Commission committed no error. No statute or administrative rule requires the Commission to calculate such estimates on an NPV basis. Indeed, the Commission calculated the benefit in the Companies' third ESP proceeding in *nominal* dollars.[167] Moreover, as Sierra Club demonstrates, calculating the likely estimate on an NPV basis still yields a benefit to customers of $37 million for Rider RRS alone. Only if the Commission had performed this calculation inconsistently, *e.g.*, by relying on nominal dollars for the Companies' projection while using an NPV basis for Wilson Scenario 1, would Sierra Club potentially have a legitimate point. But the Commission did not act inconsistently. Thus, Sierra Club's suggestion is meritless, and rehearing on this issue should be denied.

4. The Commission reasonably authorized recovery of legacy costs through Rider RRS.

Sierra Club argues that the Commission erred in the Order by providing for the recovery of Legacy Costs through Rider RRS.[168] Sierra Club makes three claims in support of this argument: (1) the Commission allegedly approved recovery of Legacy Costs without requiring

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[165] Sierra Club AFR, p. 24.

[166] Sierra Club AFR, p. 23.

[167] *See* Case No. 12-1230-EL-SSO, Opinion and Order, p. 56 (July 18, 2012).

[168] Sierra Club AFR, p. 44.

the Companies to meet their burden of proof by "disclos[ing] the specific monetary amounts that would be deemed reasonable" for recovery;[169] (2) the Commission allegedly "signed off on the recovery of a large category of costs without knowledge about the amount of such costs";[170] and (3) the Commission allegedly failed to "explain its rationale" when it approved recovery for Legacy Costs.[171] Each of these putative claims fails, and the Commission should deny rehearing accordingly.

As an initial matter, the Companies' Proposal regarding Rider RRS has rendered Sierra Club's first two arguments moot. As explained by Company witness Mikkelsen, under the modified version of Rider RRS, among other things, "actual costs will be replaced with the costs which are already evidence of record and relied upon by the Commission in this case."[172] As a result of this minor modification:

> The Proposal will preserve the benefits of the Stipulated ESP IV for customers as previously determined by the Commission. *Certain parties' concerns are addressed since FES will no longer have any involvement in how Rider RRS is determined.* The benefit of locking in the cost and generation assumptions eliminates concerns of certain parties related to extended outages, capital spending levels, operating costs exceeding projections, Plant retirements, *whether or not costs are legacy costs*, and environmental compliance risks and costs.[173]

Thus, under the Proposal, the issue of whether a particular cost is a Legacy Cost, and the specific amount thereof, no longer raises any concerns. This is so because the calculation of Rider RRS now will rely on the Companies' projected costs (already in the record), instead of actual Plant

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[169] Sierra Club AFR, p. 44.

[170] Sierra Club AFR, p. 45.

[171] Sierra Club AFR, p. 45.

[172] Mikkelsen Rehearing Test., p. 5.

[173] Mikkelsen Rehearing Test., p. 6 (emphasis added).

costs (whereby a given Legacy Cost Component could occur in a specific amount). Nevertheless, as part of the Rider RRS annual audit, the Companies will provide audited accounting information as contemplated in the Order.[174] As such, Sierra Club's complaint regarding specific amounts of Legacy Cost components has been effectively mooted. Accordingly, the Commission should deny rehearing on this issue.

In any event, even if Sierra Club's complaints had not been mooted (which in fact they have), Sierra Club's arguments along these lines would still fail. As the record demonstrates, Legacy Costs, by definition, are costs incurred due to decisions or commitments made, or contracts entered into, prior to December 31, 2014. Specific quantifiable amounts for Legacy Cost Components involving, for instance, contractual events that have not yet occurred are not presently calculable. Thus, the actual cost amounts that comprise specific Legacy Cost Components cannot be disclosed, or even ascertained, until the Plants would actually incur a Legacy Cost Component pursuant to a legacy commitment or contract.[175] Sierra Club's claims of Commission error on this score are mistaken.

Sierra Club's third claim regarding an alleged failure of the Commission to "explain its rationale" for permitting Legacy Cost recovery fares no better. The Commission has previously considered and rejected this contention, and it should be dismissed for this reason alone. Indeed, in the Order, the Commission specifically responded to concerns regarding the recovery of legacy costs by requiring the Companies to submit audited accounting information:

> With respect to legacy costs, the Commission directs the Companies to provide to the Staff audited accounting information establishing the amount of legacy costs. Further, the Commission directs the auditor in the first annual audit to verify the information

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[174] Mikkelsen Rehearing Test., p. 17.

[175] Sierra Club Ex. 40C.

> provided by the Companies to serve as a baseline for future audits.[176]

Given the Commission's consideration and rejection of Sierra Club's prior arguments regarding Legacy Costs, and given the audit requirements for Legacy Cost Components set forth in the Order, Sierra Club's contention is meritless. Accordingly, the Commission should deny rehearing on this issue.

5. Criticisms of Rider RRS because of the flow of revenues to FES are now moot.

After considering the parties' arguments and the evidence, the Commission concluded that "it is not convinced by the claims of several parties that Rider RRS is anti-competitive." The Commission correctly found that safeguards imposed in the annual prudency review process "are more than sufficient to protect against anticompetitive subsidies pursuant to R.C. 4928.02(H)."[177] EPSA and P4S claim the Commission erred in finding that Rider RRS does not provide an anticompetitive subsidy to FES.[178] EPSA asserts that Rider RRS will be collected as a distribution charge for the benefit of FES even though it is a generation charge. According to EPSA, the Commission failed to consider evidence that Rider RRS shifts the risks of FES's plants to the Companies' customers, and nothing in Rider RRS prohibits FES from using the subsidy to adjust pricing in the wholesale or retail markets.[179] In addition, EPSA and Dynegy contend that the Commission failed to substantively address the threats Rider RRS poses to

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[176] Order, p. 90.

[177] Order, p. 110.

[178] EPSA AFR, pp. 19-22; P4S AFR, pp. 8-9.

[179] EPSA AFR, pp. 71-75.

wholesale and retail markets and the siting of new generation in Ohio.[180] All these arguments were raised previously and properly rejected by the Commission.[181]

These arguments are not only unfounded but also moot as a result of the Companies' proposed modifications to how Rider RRS is calculated. Under the Proposal, there is no contract with FES, no payments to FES, and the Companies will not offer the Plants' output into the market. Thus, there is no impact on FES and no purported impact on wholesale or retail markets.

Even if Rider RRS were not moot, the Commission properly found it would not be a subsidy to FES. As the Companies explained in briefs, if Rider RRS would not result in a net charge to customers, several intervenors admitted at hearing that Rider RRS would not be a subsidy.[182] Moreover, Rider RRS provides value to customers regardless of whether it is a credit or charge in a given year. It operates as a valuable hedge against fluctuating market rates and stabilizes customer bills. Accordingly, Rider RRS does not result in an anticompetitive subsidy to FES.

In addition, the Commission found that alleged impacts of Rider RRS on the wholesale market are outside the scope of this proceeding involving approval of a retail hedge.[183] Further, as the Companies explained in briefs, claims regarding purported impacts on wholesale markets are utterly lacking support in the evidentiary record, and contrary to the realities of the PJM market.[184] Consequently, EPSA and Dynegy have made no showing that the Commission's conclusion was unreasonable or unlawful.

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[180] EPSA AFR, pp. 71-75; Dynegy AFR, pp. 21-25.

[181] *See*, *e.g.*, Order pp. 53, 58, 62, 76-77, 101, 102, 104, 110.

[182] Companies' Post-Hearing Reply Brief, p. 115.

[183] Order, pp. 86-87.

[184] See Companies' Post-Hearing Reply Brief, pp. 117-121.

6. The Commission properly found Rider RRS will mitigate retail rate volatility.

The Commission properly found that Rider RRS will mitigate retail rate volatility.[185] Some of the parties contend, however, that the Commission erred in finding that retail rate volatility even exists. Sierra Club contends that there is no evidence of rate volatility during the next eight years. Responding to predictions of volatility based on the testimony of Company witness Rose, Sierra Club argues that witness Rose forecasts wholesale prices, not retail.[186] EPSA similarly asserts that there is the lack of a correlation between daily wholesale power price volatility and SSO retail rates.[187]

These arguments were raised previously and are incorrect.[188] As the Companies explained in briefs, 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.[189] Further, the analysis conducted by EPSA's witness Dr. Kalt omitted important details, instead focusing on sensitivities related to one variable, and the Commission found it to be of little value as a projection of net credits or costs of Rider RRS over the eight-year term.[190]

Several parties contend that Rider RRS will only cause retail rate instability. Sierra Club argues that there is no evidence that RRS will counteract volatility.[191] EPSA argues that Rider RRS will not stabilize retail prices because: (1) it does not guarantee enough of a credit to offset volatility; and (2) the quarterly reconciliations will not be countercyclical and will decrease

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[185] Order, p. 80.

[186] Sierra Club AFR, pp. 36-42.

[187] EPSA AFR pp. 66-71.

[188] Sierra Club Initial Post Hearing Brief, pp. 78-80; ELPC Initial Post Hearing Brief, p. 37

[189] Companies' Post Hearing Reply Brief, pp. 125-26; Companies' Initial Post Hearing Brief, pp. 24, 42-45.

[190] Order, p. 85.

[191] Sierra Club AFR, pp. 36-42.

stability.[192] These arguments were raised previously.[193] The argument that Rider RRS's stabilizing effects are minor was rebutted by testimony 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.[194] Also, the argument that Rider RRS will decrease stability because it will not be countercyclical was rebutted by testimony that reconciliation components would not be expected to have a material effect on the overall benefit that is expected over the term of Rider RRS.[195] Further, the Commission has considered and rejected this argument, not only in the Order but also previously in its *AEP ESP3* Order.[196]

OMAEG rehashes another argument previously raised, contending that many customers have fixed price contracts so Rider RRS actually adds uncertainty.[197] As shown previously, 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.[198] Also, it is not uncommon for shopping customers to experience significant increases in price volatility when transitioning from one fixed-price contract to the next. These significant increases in volatility can be exacerbated by severe weather events such as the 2014 Polar Vortex and the 2015 Siberian Express. Further, a shopping customer's retail electric price includes a risk premium associated with anticipated wholesale market price volatility that CRES providers "bake into"

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[192] EPSA AFR, pp. 66-71.

[193] Sierra Club Post Hearing Brief, pp. 77-78; OCC/NOAC Post Hearing Brief, pp. 85-88; ELPC Post Hearing Brief, pp. 37-38; EPSA Post Hearing Brief, p. 16; Exelon Post Hearing Brief, p. 16.

[194] Companies' Post Hearing Reply Brief, p. 128.

[195] Companies' Post Hearing Reply Brief, pp. 126-27.

[196] Companies' Post Hearing Reply Brief, pp. 127-28.

[197] OMAEG AFR, pp. 23-26.

[198] Companies' Initial Post Hearing Brief, pp. 42-43.

subsequently available fixed-price retail contract offers.[199] The record further demonstrates that arguments that SSO pricing is fixed for three years are incorrect, and that staggering and laddering of SSO supply contracts does not make Rider RRS's mitigation of market price fluctuations unnecessary.[200] Accordingly, these parties have failed to show that the Commission's conclusion was unreasonable or unlawful.

C. Rider RRS Will Not Create Incentives Affecting The Companies' Offer Strategy.

Sierra Club asserts, without explanation, that the Commission modified Rider RRS in a way that could affect offer strategy and cost customers money.[201] While this argument is moot as a result of the Proposal, speculation that the Companies lack incentives to offer the Plants' output and to maximize revenues in the PJM market was previously raised and is directly refuted by the record. Under Rider RRS as initially proposed, the revenues generated from the PJM market would be subject to after-the-fact Commission review, and if the underlying revenues were deemed unreasonable, the financial risk of that unreasonableness determination would be transferred from customers to the Companies.[202] Further, the Commission modified Stipulated ESP IV to provide that the Companies, rather than customers, will bear the burden for any capacity performance nonperformance charges incurred by the Plants.[203] As a result, Sierra Club has failed to show the Commission's decision was unreasonable or unlawful.

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[199] Companies' Post Hearing Reply Brief, pp. 129-31.

[200] *See* evidence cited in Companies' Post Hearing Brief, p. 44; Companies' Post Hearing Reply Brief, p. 131.

[201] Sierra Club AFR, p. 21.

[202] Companies' Post Hearing Reply Brief, pp. 135-38.

[203] Order, p. 92.

D. The Proposed Transaction Was Negotiated In A Good Faith Process And Produced A Result Superior To Any Potential Competitive Procurement.

Some parties contend that the Commission should have required the Companies to conduct a competitive procurement for the generation to support Rider RRS. ELPC contends a competitive procurement was necessary to ensure a reasonable price.[204] EPSA and RESA make a similar claim, and further contend that Exelon's "offer" illustrates the benefits of a competitive process, because it would provide more in credits than FES's offer.[205] Likewise, Dynegy contends that FES was subsidized by the lack of a bidding requirement and that Dynegy and Exelon would have bid at lower costs.[206]

All these arguments are moot under the Proposal because the Companies will not be procuring any generation. Even if they were not moot, these arguments were previously raised with the Commission and are incorrect. As the Companies explained at length in their Post Hearing Reply Brief, Rider RRS should not have been competitively bid under the Companies' original proposal, because the negotiation process was better than a competitive procurement. The Companies' extensive due diligence efforts and good-faith arm's length negotiations with FES resulted in a framework enabling the Companies to offer their customers a beneficial, rate-stabilizing hedge worth approximately $561 million over the eight-year term of Stipulated ESP IV. In addition, the Economic Stability Program offers numerous other unique benefits that no competitive process would have yielded.[207]

The record also contradicts parties' claims of other better offers. There is no record evidence regarding Dynegy's unfounded claim that it would offer power to the Companies at a

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[204] ELPC AFR, pp. 12-16.

[205] EPSA AFR, pp. 79-83; RESA AFR, pp. 85-89.

[206] Dynegy AFR, pp. 2-6.

[207] Companies' Post Hearing Reply Brief, pp. 156-70.

lower cost than FES. Therefore Dynegy's claim should be summarily disregarded. With respect to Exelon's indicative proposal, the Commission previously considered it and properly found it lacking. Putting aside substantial record evidence that the Exelon proposal was not even a genuine offer,[208] the Commission found it would impose too many risks on retail customers, and that it would not offer the same qualitative benefits of FES's offer.[209] Accordingly, these parties have failed to show the Commission's Order was unreasonable or unlawful in this respect.

E. Stipulated ESP IV And The Proposed Transaction Reasonably Allocate Financial Risks.

Several intervenors argue that the Commission did not properly allocate the financial risks of Stipulated ESP IV. OMAEG claims that customers bear all the cost and risks.[210] RESA argues that there is no guarantee that customers will receive any credits under the risk-sharing mechanism approved by the Commission.[211] However, these arguments hinge on several assumptions, none of which are persuasive. First, the Commission considered each of the forecasts presented in the case and found that a reasonable projection results in a credit to customers of $256 million for the term of Rider RRS.[212] In addition, average customer bills cannot increase for the first two years of Rider RRS.[213] As another added customer protection, the Commission found that the $100 million credit in years five through eight of the ESP was reasonable.[214] In light of these protections, the Commission need not grant rehearing on this issue. There are already considerable consumer protections built into the ESP. As previously

[208] *See* Companies' Post Hearing Reply Brief, pp. 172-80.

[209] Order, pp. 99-100.

[210] OMAEG AFR, p. 51.

[211] RESA AFR, p. 48.

[212] Order, p. 78.

[213] Order, p. 86.

[214] Order, p. 91.

discussed, Rider RRS is designed as a hedge, not a guarantee,[215] and the Commission properly balanced customer risks in making its decision.

F. There Was No Error Regarding The *AEP ESP3* Order Factors.

1. The Commission's reference to the non-binding factors in the *AEP ESP3* Order did not deprive OCC of due process and, regardless, is now moot.

OCC argues that the Commission's reliance on the non-binding factors from the AEP ESP3 decision[216] for reviewing PPA-type riders – *i.e.,* riders seeking cost recovery for specific Plants under a PPA – are unreasonable and unlawful.[217] Of course, if the Commission grants rehearing to accept the Companies' modified Rider RRS, this argument will be rendered moot because the modified Rider RRS is not a PPA-type rider and will not recover plant costs. Moreover, the Companies previously refuted OCC's arguments,[218] and the Commission declined to adopt any new factors. OCC offers no new additional arguments on this point.

OCC claims that the Commission unlawfully denied intervenors due process by relying on the non-binding factors set out in the *AEP ESP3* Order.[219] OCC generally relies on *Ohio Bell Tel. Co. v. Pub. Util. Comm.*, 301 U.S. 292, 304-305 (1937), for its claim to due process, but that decision simply requires that parties have an opportunity to challenge potential findings of fact at a hearing (if a hearing is required). OCC was well aware the Commission would take the AEP ESP3 factors into consideration. Indeed, the Commission gave OCC and other parties an

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[215] Companies' Post Hearing Reply Brief, p. 217.

[216] *See 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, p. 25 (Feb. 25, 2015) ("*AEP ESP3* Order").

[217] OCC AFR, pp. 69-72.

[218] *See* Companies' Post Hearing Reply Brief, p. 220.

[219] OCC AFR, p. 66.

opportunity to present evidence on those factors in an evidentiary hearing,[220] which is what the *Ohio Bell* decision requires. OCC's claim willfully fails to recognize the ample due process the Commission provided regarding the AEP ESP3 factors.

Moreover, the *AEP ESP3* Order was effective immediately,[221] and OCC fails to cite any statutory or common law requirement that the Commission may only rely on precedent from cases where applications for rehearing have been denied. Contrary to OCC's position, it has not been denied due process because OCC's challenges asserted in the *AEP ESP3* case remain pending. OCC has not stated grounds for rehearing.

2. Rider RRS satisfies the non-binding criteria set forth in the *AEP ESP3* Order.

Several parties contend that the Commission erred in its application of the non-binding factors the Commission developed in the *AEP ESP3* Order. As an initial matter, these parties ignore the Commission's clear statement in the Order that the Commission's approval of Rider RRS did not turn on its consideration of the AEP factors:

> While the Commission is sympathetic to concerns surrounding the potential additional transmission costs, resource diversity, and local economic impact, the Commission's decision does not turn on such issues. As stated above, our decision today is based upon our retail authority under state law and is consistent with federal law.[222]

Further, as noted above, all complaints regarding these factors are now moot because the Proposal does not rely in any way on a PPA or other contractual relationship with FES. The Commission developed the non-binding factors to aid it in deciding whether to approve a

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[220] *See* March 23, 2015 Entry modifying the procedural schedule "[i]n order for the parties to address whether and how the Commission's findings in the AEP Ohio Order should be considered in evaluating FirstEnergy's application in this proceeding."

[221] R.C. 4903.15.

[222] Order, p. 87.

utility's request for cost recovery under a PPA Rider. The factors relate to the circumstances of generating units whose output is sold to the utility under a PPA, and the impacts of retiring the generating units on reliability, retail electric prices, and the regional economy. Because the Proposal includes no PPA, and implicates no generating units, the AEP factors no longer apply.

Even if the AEP factors were still applicable to Rider RRS, the parties challenging the Commission's consideration of those factors failed to show the Commission's Order was in any way unreasonable or unlawful.[223]

G. The Proposed Transaction Includes Rigorous Commission Oversight And Full Information Sharing.

Several parties attack various aspects of the Commission's rigorous oversight of Rider RRS, or other customer protections implemented by the Commission. OCC contends that the Commission's rigorous review process does not protect against anti-competitive subsidies because the Companies can sell the Plants' output to FES through a bilateral contract, and the contract would not be subject to Commission review.[224] Under the Proposal, this issue is moot because the Companies will not have the Plants' output to sell to FES. Further, the lack of Commission jurisdiction over a bilateral contract between the Companies and FES is not a bar to the Commission's ability to disallow the Companies' recovery of costs under Rider RRS. As a result, the Commission has ample authority over the Companies to follow through on its promise to address any violation of the prohibition against anti-competitive subsidies.

Dynegy argues that the Commission's financial audit, through an initial mathematical verification and subsequent review of costs in Rider RRS, is not enough. Instead, Dynegy argues that the Commission needs a substantive review and oversight of the Companies' activities under

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[223] *See* Companies' Post Hearing Reply Brief, pp. 195-217.

[224] OCC AFR, p. 43.

the PPA, as well as oversight over FES.[225] This concern was raised previously.[226] Again, the concern is largely moot under the Proposal, in which Rider RRS does not implicate a PPA with FES. Further, the Companies explained in briefs that the Commission has full authority to review not only the costs, but also "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."[227] As stated in Company witness Mikkelsen's Rehearing Testimony, Staff nevertheless will have the opportunity to perform a rigorous review of Rider RRS.[228] Therefore the Commission's rigorous oversight process is more than sufficient, and the parties have not made a showing that the Commission's decision is unreasonable or unlawful.

H. Criticisms of the Economic Benefits of Rider RRS Are Unfounded And Now Largely Moot Under Modified Rider RRS.

Sierra Club makes a blanket statement that economic development benefits of Rider RRS are "illusory,"[229] while EPSA states that there is no evidence to support any economic benefits.[230] The red herring here is these intervenors' insistence that the Companies had to prove that the Plants would retire but for the Economic Stability Program. To the contrary, economic development programs are often designed to provide additional incentives to maintain and grow jobs and other economic benefits, not simply to stave off inevitable business closures. When the Commission approved the Companies' economic development program for the Cleveland Clinic

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[225] Dynegy AFR, pp. 19-21.

[226] *See, e.g.*, OCC/NOAC Post Hearing Brief, p. 82.

[227] Companies' Post Hearing Reply Brief, pp. 14445 (quoting Hearing Tr. Vol. XXXVI, p. 7701 (Mikkelsen Cross)).

[228] Mikkelsen Rehearing Test., pp. 16-17.

[229] Sierra Club AFR, p. 17

[230] EPSA AFR, p. 65

in the Companies' ESP2, the Commission did not require proof that the Clinic would close but for this program. Such a requirement would be absurd, but that is exactly the requirement Sierra Club and others seek to impose here. They state no grounds for rehearing.

Moreover, this argument is largely moot once the Companies' proposed modifications to how Rider RRS is calculated are accepted by the Commission. Economic benefits from modified Rider RRS no longer depend upon specific Plants. Instead, they arise from the Commission's authority to reduce Rider RRS charges proportionately if, while Rider RRS is in effect, less than 3,200 MW of formerly rate-based nuclear or fossil generation owned by the Companies on January 2000 remains in operation, including at least 900 MW of nuclear resources which may be needed to help meet any potential 111(d) state implementation plan.[231] As the Commission has recognized, based on the existing record, continued operation of fuel-diverse baseload generating units provides significant positive economic and tax impact for employees, suppliers, and governmental entities in the region.[232]

The evidence in the record is undisputed. Company witness Murley prepared the only economic impact analysis for the Plants in this case. The analysis shows an ongoing economic benefit of over $1.1 billion annually[233] and a lost economic benefit of over $1.1 billion if the Plants close.[234] Absent from the intervenors' arguments are any facts or contradictory evidence to the industry standard model used by Ms. Murley, which is indicative of a lack of understanding of economic impact analysis.[235]

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[231] Mikkelsen Rehearing Test., p. 15.

[232] Order, p. 88.

[233] Murley Supp., p. 11.

[234] Murley Supp., p. 11; Hearing Tr. Vol. XV at 3214:25-3217:2 (Murley Cross).

[235] Companies' Initial Post Hearing Brief, p. 214.

For example, NOPEC claims that Ms. Murley "entirely fails" to take into account a possible decommissioning process with regards to Davis-Besse.[236] This argument, however, shows absolutely no recognition of Ms. Murley's testimony.[237] Ms. Murley specifically accounted for a decommissioning scenario, which she concluded would have minimal economic impact, and certainly an impact considerably less positive than ongoing operations.[238]

NOPEC and OMAEG argue that Ms. Murley's study did not take into account the effect higher electric prices would have on the economy, but they failed to produce any credible evidence that Rider RRS would result in higher electric prices over its eight-year term.[239] To the contrary, the Commission found, based on credible evidence in the record, that customers will see a decrease in electric prices resulting from Rider RRS credits.[240] Indeed, by not including the positive impact of Rider RRS on customers' retail electric rates, Ms. Murley's study was conservative. Any argument to the contrary is incorrect and is unsupported by record evidence.

Intervenors have failed to state valid grounds for rehearing on this issue.

I. The Credit Sharing Provision Is Adequate.

In Stipulated ESP IV, the Companies agreed to provide up to $100 million in credits to benefit customers during years 5 through 8, in the event Rider RRS is a charge during those years. The Commission properly approved this commitment, and added further customer protections discussed elsewhere in this Memorandum Contra. OMAEG attacks the approval of the $100 million in credits. According to OMAEG, if the Companies' projections are correct,

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[236] NOPEC AFR, p. 17

[237] In addition, NOPEC's argument completely overlooks the Companies' Post Hearing Reply Brief at pages 215-216, which also refuted the identical claim NOPEC argues here.

[238] Companies' Post Hearing Reply Brief, p. 216; Murley Supp., p. 10.

[239] NOPEC AFR, pp. 17-18; OMAEG AFR, p. 48

[240] Order, p. 78.

none of the $100 million will be paid between years 5 and 8 because Rider RRS will always be a credit to customers. If, on the other hand, OCC witness Wilson's projections are correct, Rider RRS will be a charge, and the $100 million in credits will merely reduce the charge, not eliminate it. OMAEG complains that "[t]his is hardly risk for the Companies."[241]

As an initial matter, the Commission correctly rejected OCC witness Wilson's worst case projections, as explained above. Further, this argument fails to recognize that if the risk sharing mechanism is not triggered, it means customers are receiving credits under Rider RRS and Rider RRS is working as intended, to the benefit of customers. If the risk sharing mechanism is triggered by charges during years 5 through 8, it means the customers' charges are reduced by up to $100 million, and customers are enjoying low power prices while they continue to receive valuable insurance against price volatility, as well as the other benefits of Rider RRS. As a result, OMAEG fails to show that the Commission's decision is in any way unreasonable or unlawful.

J. Commission Modifications To Rider RRS Were Not Unreasonable Or Unlawful.

1. The two-year limit on average customer bills is an added precaution intended to assist customers.

While Stipulated ESP IV provided robust protection for customers, the Commission took an added precaution by including a mechanism to ensure the average customer bill will see no average bill increase for the first two years of Rider RRS.[242]

EPSA and RESA claim the Commission erred by failing to provide a "coherent formula" for calculating the two-year limit on average customer bills. According to EPSA, there is no way

[241] OMAEG AFR, pp. 51-54.

[242] Order, p. 86.

to tell if the mechanism will have a negative or beneficial effect for customers. EPSA further contends that during the first two years, customers should be informed of the impact these limits are having, through disclosure of the rate impact and dollar amounts.[243] Similarly, OMAEG requests clarification regarding the mechanism, the costs that are subject to it, and how it is calculated, as well as clarification regarding the deferrals.[244] Contrary to these parties' suggestions, the Commission's bill increase limitation mechanism will obviously have a beneficial effect for customers, since it imposes a limitation on average customer bill increases that otherwise would not have existed. Also, the Order provides ample detail about how the mechanism will work, including (i) the baseline year, (ii) the consideration of seasonal rate differential and over or under recoveries for prior periods, (iii) the exclusion of costs recovered for smart grid deployment, renewable energy procurement and Rider AER, and the impact on riders resulting to credits to customers due to disallowance, and (iv) the inapplicability of any over or under-recoveries of Rider RRS from prior periods.[245] The Applications for Rehearing are conspicuously devoid of specifics as to what further details these parties would like. They fail to show that the Commission's Order was unreasonable or unlawful.

EPSA and RESA also argue that the two-year limit on increases in average customer bills is "of virtually no value" to customers. They claim that use of average customer bills for the period of June 1, 2015 through May 31, 2016 still allows the potential for increases above customer bills during that period that were below average, that there is no reason the mechanism should apply for just the first two years of ESP IV, and that the mechanism still allows quarterly adjustments which create rate volatility. They, and OCC, further argue that allowing the

[243] EPSA AFR, p. 44; RESA AFR pp. 48-49.

[244] OMAEG AFR, p. 70.

[245] Order, p. 86.

Companies to recover deferred costs not recovered during year two will not protect customers against rate volatility.[246] These arguments ignore the basic point of the Commission's modification, which was to impose a two-year limit on total bill increases attributed to Rider RRS that would not otherwise exist. Moreover, they ignore the fact that the Commission decided not to allow the Companies to recover deferred costs not recovered during year one as a result of the mechanism. These parties make no showing that the Commission's imposition of a mechanism to limit increases in average total customer bills over the first two years of ESP IV was unreasonable or unlawful.

Sierra Club also objects to the two-year cap, arguing that it would not actually increase stability over the next two years since recent auction prices suggest prices would have been lower than they are currently through at least the 2017/2018 planning year.[247] This argument evidences a misunderstanding of the purpose of Rider RRS. The purpose of Rider RRS is to stabilize prices. The Rider may be a charge in years when prices are very low and may be a credit when prices are higher. Rider RRS acts as a counter-cyclical hedge to protect customers from rising prices over the long term. Rather than being an error, the Commission's two-year cap was an appropriate method to stabilize prices in the next two years while ensuring customers will receive the benefits of Rider RRS over the entire eight-year term.

OCC further argues that the Commission erred by allowing the Companies to retain capacity performance bonus payments, because this creates an incentive for the Companies not to make the units clear in the capacity auctions, and by failing to reserve the right to further modify Stipulated ESP IV if the units do not clear in the capacity auctions, by requiring the

[246] EPSA AFR, pp. 54-56; OCC AFR, pp. 54-62; RESA AFR, p. 59.

[247] Sierra Club AFR, pp. 41-42.

Companies to clear the units by offering them as price takers.[248] These arguments are moot in light of the Proposal, under which revenues, for purposes of Rider RRS calculations, do not depend on whether the units clear the capacity auction. Also, the Companies will not offer the units' capacity into auctions under the Proposal. Even if these issues were not moot, OCC is incorrect about the Companies' incentives to maximize revenues, for the reasons explained at length in the Companies' Reply Brief.[249] The rigorous review process adopted in the Commission's Order satisfactorily addresses OCC's concerns as well. Further, as the Companies explained in their Reply Brief, OCC's recommendation that the Commission require the Companies to clear the units in the capacity auctions is arguably an invitation to the Commission to intrude in areas of exclusive federal jurisdiction.[250] Therefore, OCC's arguments must be rejected.

2. The balancing of risks reflected in Rider RRS is reasonable.

EPSA contends that Stipulated ESP IV's risk sharing mechanism for years 5-8 does little to mitigate the risks of Rider RRS, and that the Commission should have adopted annual or aggregate caps on Rider RRS charges.[251] These parties previously raised these arguments, which the Commission considered in its Order.[252] The Commission disagreed with EPSA's argument that the risk sharing mechanism is inadequate, finding that it "appropriately balances legitimate customer concerns about prices with the interests of other stakeholders."[253]

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[248] OCC AFR, pp. 57-59, 62.

[249] *See* Companies' Post Hearing Reply Brief, pp. 135-139.

[250] *See* Companies' Post Hearing Reply Brief, p. 291.

[251] EPSA AFR, pp. 41-44.

[252] Order, pp. 63-64.

[253] Order, p. 91.

Further, the Commission modified Stipulated ESP IV's risk sharing mechanism by clarifying that the Companies will be precluded from recovering the costs associated with the credits in any future Commission proceeding, consistent with their intent as evidenced during the hearing. The Commission also added protections for customers, such as clarification that no plant retirement costs may be recovered through Rider RRS, provision that the burden of Capacity Performance penalties and the benefit of Capacity Performance bonuses will reside with the Companies and not customers, and a reservation of the right to prohibit recovery of any costs related to any unit for any period exceeding 90 days for any forced outage during the term of ESP IV.[254]

In addition, the Commission did in fact modify Stipulated ESP IV by adopting a form of cap, through the mechanism that limits average customer bills for the first two years of Stipulated ESP IV, and allows the Companies only to defer expenses in the amount of the revenue reduction resulting from implementation of this mechanism for the second year.[255] As a result, EPSA has failed to show how the Commission's Order is unreasonable or unlawful.

3. Refunds are not necessary or appropriate here.

Several parties contend that the Commission's Order upon rehearing should provide for refunds of Rider RRS charges if a court or the FERC finds the charges were unlawfully collected, or that Rider RRS is somehow precluded.[256] EPSA, OMAEG and RESA further take issue with the Third Supplemental Stipulation's severability provision, which states that "[n]o

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[254] Order, p. 92. These clarifications and modifications are moot, as a result of the Proposal which no longer connects Rider RRS charges to actual Plant costs.

[255] Order, p. 86.

[256] EPSA AFR, pp. 85-86; NOPEC AFR, pp. 6-7; OCC AFR, pp. 72-77; OMAEG AFR, pp. 51-54; RESA AFR, pp. 84-85.

amounts collected shall be refunded as a result of this severability provision."[257] These parties contend that the Commission should have modified the severability provision to remove this language, a deletion the Commission made to AEP's severability provision.[258]

These parties previously raised this argument, but the Commission did not adopt it in its Opinion and Order.[259] There is no reason for the Commission to adopt it here, either. The language of the Third Supplemental Stipulation's severability provision with which these parties take issue merely states the law of Ohio, which does not allow refunds based upon the prohibition against retroactive ratemaking.[260] The Commission's deletion of the language from AEP's severability provision did not change Ohio law. Moreover, these parties overlook other material differences in the AEP Order, such as the Commission's allowing AEP to defer expenses for future recovery in an amount equivalent to the revenue reduction resulting from implementation of the average customer bill limitation for the first two years of AEP's PPA Rider, as opposed to only the second year for the Companies. Consequently, these parties have not stated how the Commission's Order is unreasonable or unlawful.

4. Delays would frustrate the purpose of Rider RRS.

EPSA and RESA argue that the Commission erred in approving an effective date for Rider RRS of June 1, 2016. They contend that the effective date of Rider RRS should be the later of an Ohio Supreme Court decision upholding the validity of Rider RRS, or FERC approval of the PPA with FES.[261]

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[257] Third Supp. Stip. Section V.B.3.c.

[258] EPSA AFR, pp. 85-86; OCC AFR, pp. 59-60; OMAEG AFR, pp. 51-54; RESA AFR, p. 91.

[259] *See, e.g.*, RESA Post Hearing Brief, p. 34; *see* Order, pp. 64-65, 103-104.

[260] *See, e.g., Keco Industries, Inc. v. Cincinnati & Suburban Bell Telephone Co.*, 166 Ohio St. 254 (1957); *In re Columbus Southern Power Co.*, 128 Ohio St. 3d 512, 515-516 (2011)..

[261] EPSA AFR, pp. 86-87; RESA AFR, p. 92.

These arguments are moot to the extent they advocate delay based upon a need for FERC approval of a PPA or the disposition of the EPSA Complaint. As explained above, the Companies' Proposal includes no PPA with FES, nor any other connection to FES. Further, these arguments for delay were already raised and considered by the Commission.[262] The Application was filed with the Commission on August 4, 2014. Since then, a voluminous record was assembled regarding all aspects of the proposal, and a Third Supplemental Stipulation was reached with numerous parties.[263] Further, the Companies' Proposal simplifies the proceeding by eliminating the need to resolve many questions related to a PPA with FES, such as issues regarding access to plant cost information, actual plant costs, and the Companies' offering of plant output. The Commission had all of the information it needed to render a decision in the Order, and opponents have failed to show how not further delaying this proceeding was unreasonable or unlawful.

K. Rider DCR As Proposed In Stipulated ESP IV Should Be Approved.

Rider DCR benefits customers by promoting system reliability.[264] Indeed, it is undisputed that since Rider DCR has been in effect, the Companies have consistently outperformed their reliability standards.[265] 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.[266] The initial

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[262] Order, pp. 104-05.

[263] Companies' Post Hearing Reply Brief, p. 296.

[264] Mikkelsen Direct, p. 8; Hearing Tr. Vol. XX, pp. 3927-28 (Company witness Fanelli describing benefits to customers arising from Rider DCR).

[265] Mikkelsen Direct, pp. 9-10; Hearing Tr. Vol II, p. 252 (Mikkelsen Cross); Nicodemus Direct, pp. 9-10.

[266] Third Supp. Stip., Section V.G.2.

$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.[267]

OCC/NOAC criticize the Commission's approval of Rider DCR, claiming that it will cause distribution rates to be unstable.[268] Nothing could be further from the truth. Rider DCR has established caps that keep annual increases in the rider amount, if any, to a known and predictable level. In contrast, base distribution cases may cover multiple years and cause a less predictable and potentially larger increase all at once. Rider DCR better allows customers to plan and budget over time, and reduces "spikiness" in rate levels that may be the result of base distribution rate cases. OCC/NOAC also criticize the Commission for failing to discuss the change in Rider DCR cap levels in the Order.[269] But OCC/NOAC is wrong on this as well. The Commission addressed Rider DCR in some detail on pages 65-66 and page 93 of the Order, and specifically detailed the Rider DCR cap levels at page 66. OCC/NOAC's concerns in this regard are without merit.

OMAEG also opposes the approval of Rider DCR on a number of grounds, all without merit and based upon a number of erroneous statements in its Application for Rehearing.[270] First, OMAEG states that the Commission has provided no record evidence to support the need for Rider DCR or to provide any evidence, or rationale, to support the $180 million in increased revenue caps.[271] To begin, the Commission doesn't provide evidence in a proceeding; OMAEG's statement in this regard is wrong. If OMAEG meant to assert that the Commission

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[267] Fanelli Direct, pp. 3-4; Hearing Tr. Vol. XX, pp. 3955-58 (Fanelli Cross).

[268] OCC/NOAC AFR, p. 22.

[269] OCC/NOAC AFR, p. 22.

[270] OMAEG AFR, pp. 32-37.

[271] OMAEG AFR, p. 33.

failed to discuss the issue in a manner consistent with R.C. 4903.09, then OMAEG is wrong since Rider DCR is discussed at length in the Order at pages 65-66 and 93.[272] If it intended to say that there was no record evidence in the case, then that, too, is wrong. Both Mr. Fanelli and Ms. Mikkelsen discussed Rider DCR at length in their testimonies. Mr. Nicodemus, on behalf of Commission Staff, discussed Rider DCR in his testimony as well.[273]

OMAEG next complains that Rider DCR should not be expanded to include general and intangible plant.[274] But the Companies are not seeking to "expand" Rider DCR in terms of the types of costs it is permitted to recover. General and intangible plant related to the distribution system has been recovered through Rider DCR since its initial approval in 2012.[275]

OMAEG next contends that Rider DCR is based on R.C. 4928.143(B)(2)(h), and that evidence is lacking that the interests of the Companies and its customers are aligned related to distribution reliability and expenditures.[276] To the contrary, both Company witness Mikkelsen and Staff witness Nicodemus specifically demonstrated that the Companies' and customers' reliability expectations are in fact aligned.[277] In fact, Staff witness Nicodemus testified that the Companies' reliability expectations are consistent with those of their customers and they have met the requirements of R.C. 4928.143(B)(2)(h).[278] OMAEG's contention in this regard should be rejected because it has not demonstrated grounds for rehearing.

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[272] OMAEG makes reference on page 33 to R.C. 4903.90, but since there is no 4903.90, the Companies believe the reference as intended to be to R.C. 4903.09.

[273] Mikkelsen Direct, pp. 8-13; Hearing Tr. Vol. XX, pp. 3927-28 (Company witness Fanelli describing benefits to customers arising from Rider DCR); Nicodemus Direct, pp. 9-10.

[274] OMAEG AFR, p. 33.

[275] Mikkelsen Direct, p. 11.

[276] OMAEG AFR, p. 34.

[277] Mikkelsen Direct, pp. 8-11; Nicodemus Direct, p. 10

[278] Nicodemus Direct, p. 10.

OMAEG also claims that the amounts recovered through Rider DCR have not been reviewed stating: "Further, since it has been seven years since the Companies last distribution rate case, it is both unreasonable and imprudent for the Commission to approve continued incremental increases of a distribution rate, absent a review of those rates through a distribution rate case." OMAEG apparently is unaware that the Companies' witnesses described in detail the Commission's two-tiered process used to review amounts recovered through Rider DCR: [279](1) the opportunity for a quarterly review as part of the rider's quarterly filing; and (2) more importantly, the annual review, with an outside consulting firm retained by Commission Staff, including (a) thorough audits and investigation the details of the amounts proposed to be recovered through Rider DCR, and (b) a detailed report discussing the audit and investigation findings.[280] Accordingly, OMAEG's concerns about amounts recovered through Rider DCR not being thoroughly reviewed are mistaken and wholly without merit.

OMAEG next relies on the testimony of OCC witness Effron to claim that Rider DCR should not be approved because the Companies are not earning a sufficiently low return on equity.[281] But OCC witness Effron was so discredited at hearing that not even OCC relied on his testimony in its Application for Rehearing. The Companies' fully discussed the numerous shortcomings of Mr. Effron's testimony in their Post Hearing Reply Brief at pages 222-227, and such detail need not be repeated here. In brief, Mr. Effron, who is not a rate-of-return expert, used a calculation of his own making, which both ignores the SEET test and the methodology

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[279] Mikkelsen Direct, pp. 11-12.

[280] Mikkelsen Direct, pp. 11-12.

[281] OMAEG AFR, pp. 35-36.

used in a distribution rate case, to get to a desired outcome.[282] Reliance on Mr. Effron's testimony is misplaced, and OMAEG's argument should be rejected.

OMAEG concludes its concerns with Rider DCR by attempting to rely upon the *AEP ESP3* Order,[283] but such reliance is misplaced.[284] First, the Companies' ESP IV is a stipulated case. Therefore, the Commission is required to review all of the elements of the stipulation package as a whole and consider the stipulation package against the three prongs of the stipulation test. In the AEP ESP3 case, there was no stipulation related to their Rider DIR, so the Commission's consideration and review process were significantly different between the two cases.

Second, while the Commission did not approve all elements of AEP's Rider DIR as proposed, the Commission also did not rule that such changes sought by AEP were unlawful, leaving the door open for approval in other cases.

Third, AEP was seeking to expand the scope of its Rider DIR as to the types of costs that may be recovered. There is no such expansion authority sought in the Companies' ESP IV proceeding, so the Commission had no decision to make regarding such expansion in the Companies' case.

Fourth, there was no finding or evidence in the Companies' ESP IV proceeding that the costs recovered through Rider DCR were unrelated to the distribution system. To the contrary, Company witnesses testified that the costs recovered through Rider DCR are all related to the Companies' distribution system.

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[282] See Companies' Post Hearing Reply Brief, pp. 222-27.

[283] Case No. 13-2385-EL-SSO Order issued 2-25-15.

[284] OMAEG AFR, p. 36.

Fifth, in the Companies' ESP IV case, Company witnesses presented evidence as to how the Companies and customers' expectations were aligned. For example, Ms. Mikkelsen specifically presented evidence that showed the Companies' Rider DCR contributed to reliability, that the Companies have had improving reliability since DCR was implemented, and that the Companies have consistently met or exceeded the Commission's reliability standards since Rider DCR was implemented in 2012.[285] In the *AEP ESP3* Order, the Commission found that AEP failed to provide specific service reliability improvements for each DIR program implemented.[286]

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. The parties' arguments against the approval of Rider DCR should be rejected.

L. The Rate Decoupling Section Of The Third Supplemental Stipulation Advances Ohio Policy.

OCC/NOAC argue that the Commission acted unreasonably and unlawfully by approving the Companies' plans to implement straight fixed variable ("SFV") rate design through an ESP proceeding.[287] OCC/NOAC acknowledge that R.C. 4928.143(B)(2)(h) allows for a revenue decoupling mechanism.[288] They argue, however, that SFV rate design does not qualify as a revenue decoupling mechanism because it does not promote "energy efficiency."[289]

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[285] Mikkelsen Direct, pp. 8-11.

[286] *AEP ESP3* Order, pp. 44-45.

[287] OCC/NOAC AFR, p. 44.

[288] OCC/NOAC AFR, p. 44.

[289] OCC/NOAC AFR, p. 44.

OCC/NOAC's arguments are doubly flawed. First, the Commission did not approve "plans to implement straight fixed variable rate design" by adopting the Stipulated ESP IV.[290] Instead, the Commission approved the Third Supplemental Stipulation provision that directs the Companies "to file an application to transition to SFV rate design for distribution rates."[291] The Commission explained that "the Stipulations provide for a separate proceeding where any interested party will have a full and fair opportunity to address whether the proposed SFV should be implemented and to raise any other issues specific to the Companies' service territories."[292] Thus, OCC/NOAC's objection to this provision in the Third Supplemental Stipulation continues to be grounded on their ignorance of what is in the Third Supplemental Stipulation.

Second, OCC/NOAC's purported interpretation of R.C. 4928.143(B)(2)(h) conflicts with the plain language of the statute. The statute does not require that a revenue decoupling mechanism relate to energy efficiency. Instead, R.C. 4928.143(B)(2)(h) provides that a plan may include "[p]rovisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, *a revenue decoupling mechanism* or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility." The words "energy efficiency" are not included in the section.

The Commission correctly found that the Companies' plan to file an application with the Commission was authorized as a "revenue decoupling mechanism."[293] To be sure, SFV rate design easily falls within R.C. 4928.143(B)(2)(h), because SFV rate design is a method of

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[290] OMAEG similarly complains that the Commission erred by pre-approving the Companies' proposal for SFV rate design. OMAEG AFR, p. 17. This argument fails for the same reason.

[291] Order, p. 93.

[292] Order, pp. 93-94.

[293] Order, p. 93.

revenue decoupling.[294] Accordingly, OCC/NOAC fail to show any legal error with the Commission's approval of the Companies' plan to file an application to implement SFV rate design.

In addition, OCC/NOAC and OMAEG repeat arguments from their initial briefs that SFV rate design is not in the public interest.[295] These arguments, however, remain premature because they address the merits of the Companies' future proposal. Thus, OCC/NOAC and OMAEG fail to show that rehearing is warranted.

M. Except As Set Forth In The Companies' Application For Rehearing, The Commission Acted Reasonably In Approving The Distribution Provisions in Stipulated ESP IV.

RESA argues that the Commission's approval of a base rate freeze is inconsistent with the Commission's "approval" of other provisions that change rate design.[296] RESA's argument, however, misconstrues the Order, which requires the Companies *to file* applications for these provisions in separate proceedings.[297] The Commission did not "approve" these provisions.

Nor is there any inconsistency in the Commission's approval of a base rate freeze with its approval of the Companies' plans to file applications that may affect rate design. The Stipulation makes the rate freeze subject to its other provisions, including the Companies' plan to apply for SFV rate design.[298]

OCC/NOAC argue that there is no evidence to support the Commission's creation of a zero-based rider that attempts to unbundle the costs supporting the Companies' SSO. The

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[294] *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 2010-Ohio-134, ¶¶ 36-37, 125 Ohio St. 3d 57, 63, 926 N.E.2d 261 (explaining that SFV rate design is a method of decoupling).

[295] OMAEG AFR, p. 17; OCC/NOAC AFR, p. 45.

[296] RESA AFR, pp. 103-104.

[297] Order, pp. 93, 98.

[298] Third Supp. Stip., Section G.1.

Companies agree.[299] Moreover, as set forth in the Companies' Application for Rehearing, IGS's initial unbundling proposal has been supplanted by IGS's Enhancement Agreement with the Companies, which is the preferred mechanism to incent shopping.[300] The alternative Enhancement Agreement is supported by the testimony of Company witness Mikkelsen, who testified that the purpose of such a mechanism "would potentially [be to] create greater supplier interest in participating in the competitive market for the companies, and, in turn, provide . . . a more robust competitive environment for the customers of the companies."[301] Accordingly, the Commission should grant OCC/NOAC's Application for Rehearing on this issue, but clarify that the decoupling mechanism has been supplanted by the Enhancement Agreement.

N. The Federal Advocacy Section Of The Third Supplemental Stipulation Does Not Violate Ohio Policy.

RESA argues that the Commission should clarify the Order to indicate that Stipulated ESP IV does not bind the Commission under Section V.C.3. of the Third Supplemental Stipulation.[302] This section 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."[303] This is a recommendation from the Signatory Parties that the Commission take this action if PJM fails to act.

In the Order, the Commission acted within its powers by accepting the recommendation and adopting the Stipulated ESP IV without modification. As a result, the Commission

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[299] *See* Companies' AFR, pp. 10-12.

[300] Companies' AFR, pp. 10-12.

[301] Hearing Tr. Vol. XXXVII, pp. 7927-7928.

[302] RESA AFR, p.102.

[303] Third Supp. Stip., Section V.C.3.

implicitly rejected RESA's argument that it should not adopt Section V.C.3. because the section requires the Commission to take action.[304] Although RESA points out that in the *AEP ESP3* Order the Commission found that provisions in AEP's stipulation that purport to bind the Commission would remain within the Commission's discretion,[305] RESA fails to show that the Commission erred here. Rehearing is not warranted on this issue.

O. RESA Has Failed To Demonstrate That The Commission's Denial Of Certain Competitive Market Reforms It Recommended In The Companies' Stipulated ESP IV Is Unreasonable Or Unlawful.

RESA appears to complain that the Commission failed to discuss and require certain competitive market reforms RESA recommended in approving the Companies' Stipulated ESP IV.[306] These recommendations are not new and were addressed in RESA's Initial Brief and Reply Brief (as RESA freely demonstrates in the citations in its application for rehearing).[307] As noted above, where "the application for rehearing simply reiterates arguments that were considered and rejected by the Commission," the application for rehearing should be rejected.[308]

Even if these arguments were new on rehearing, it was not unreasonable or unlawful for the Commission to reject inclusion of RESA's recommendations in the Companies' Stipulated ESP IV. Moreover, it was not unreasonable or unlawful for the Commission to reject these items without discussion. RESA's citation to *In re Application of Columbus S. Power Co.*, 2016-Ohio-

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[304] Order, p. 106 (summarizing RESA's argument that the Stipulated ESP IV is unlawful because "the federal advocacy provision requires the Commission to take action, rather than exercising its own judgment").

[305] RESA AFR, p. 103 (citing *AEP ESP3* Order, p. 91).

[306] RESA AFR, pp. 95-96.

[307] RESA Initial Brief, p. 20 ("…the Commission should require first energy to submit an action agenda to the Staff…"); *id.*, p. 17 ("The CRES supplier web portal should be approved, along with a specific directive to hold stakeholder collaborative meetings to assist with development and implementation."); *id.*, pp. 20-24 ("A purchase of receivables program should be ordered as part of FirstEnergy's Electric Security Plan.").

[308] *See, e.g., Wiley v. Duke Energy Ohio, Inc.*, Case No. 10-2463-GE-CSS, 2011 Ohio PUC LEXIS 1276, *6-7 (Nov. 29, 2011).

1608 at ¶ 66, is misplaced. In that case, the applicant, Columbus Southern Power Co. ("AEP") argued that in making a decision on AEP's SEET threshold of its ESP, the Commission erred by not explaining its decision and for departing from statutory process.[309] In contrast, the Commission explained in the Order why it permitted the Companies to include certain items (supplier portal and time-of-day ("TOD") rates) in Stipulated ESP IV. The Commission is not required to explain why it rejects RESA's (the non-applicant) wish list, and RESA has not demonstrated otherwise. Therefore, whether RESA is contending that the Commission erred in not discussing its recommendations or whether RESA is contending that the Commission erred in not including these items in the ESP (discussed further below), the Commission should deny its application for rehearing.

1. The Commission's rejection of an "action agenda" is not unreasonable or unlawful.

RESA argues that the Commission should have required an "action agenda" identifying how the Companies would provide meter data to CRES providers and limit TOD rates in Rider GEN to only customers taking service under it.[310] While RESA argues that TOD data (interval data) is needed for CRES providers to provide TOD rates, RESA never explains either in its AFR or in its Initial Brief why only existing customers should be permitted to have TOD rates.

RESA also never explains why it is unreasonable or unlawful for the Commission to fail to order an "action agenda" or limit existing customers to TOD rates – because it is not. There is no need for the Companies to submit an "action agenda" to Staff, 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

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[309] *In re Application of Columbus S. Power Co.*, 2016-Ohio-1608, ¶ 65.

[310] RESA AFR, pp. 95-96.

Retail Market Investigation Finding and Order to provide a time-differentiated-rate pilot program.[311] 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 filing of a grid modernization business plan.[312] Finally, the Commission rejected the Companies' change to their supplier tariff related to non-summary customer usage data – an issue recommended by RESA.[313]

RESA's unsupported contention that the continuation of the TOD option under Rider GEN should be limited to only those customers currently taking service under it should likewise be rejected. This recommendation is unfounded and is inconsistent with the current Commission-approved tariff. Limiting participation in this manner would deny customers an opportunity to lower their electric bills and better understand the benefits of time-differentiated pricing.[314] Therefore, RESA's application for rehearing should be denied on this issue.

2. The Commission's rejection of a web portal collaborative is not unreasonable or unlawful.

RESA argues that the Commission should have required a collaborative "to assist in the development and implementation of the CRES web portal."[315] Again, RESA fails to explain how it was unreasonable or unlawful for the Commission not to adopt RESA's recommendation to require a web portal collaborative in the Companies' Stipulated ESP IV. As part of the retail market enhancements in Stipulated ESP IV, the Commission properly approved the Companies'

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[311] Hearing Tr. Vol. XXVI, p. 5355.

[312] Third Supp. Stip., Section V.D.2.c.

[313] Order, p. 98.

[314] Companies' Initial Post Hearing Brief, p. 34.

[315] RESA AFR, p. 96.

proposed supplier web-portal.[316] However, the Commission also properly did not require a stakeholder collaborative because, as the Companies demonstrated, RESA failed 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 identify any information that was missing.[317] He also agreed that RESA is not proposing any changes to the portal described in Ms. Smialek's testimony.[318] The Commission acted reasonably in not requiring a stakeholder process 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.[319] Given the lack of demonstrated need for an additional collaborative process, there was no basis for the Commission to require one. Therefore, the Commission should deny RESA's application for rehearing on this issue.

3. The Commission's rejection of a purchase of receivables program is not unreasonable or unlawful.

RESA argues that the Commission should have required a purchase of receivables ("POR") program as part of the Companies' Stipulated ESP IV.[320] Yet RESA fails to explain how it was unreasonable or unlawful for the Commission not to adopt RESA's recommendation to require a POR program in the Companies' Stipulated ESP IV.

As the Companies discussed in their Reply Brief, RESA failed to demonstrate any evidentiary support for a new, undefined POR in the Companies' Stipulated ESP IV.[321] RESA

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[316] Order, p. 76.

[317] Hearing Tr. Vol. XXVI, p. 5353.

[318] Hearing Tr. Vol. XXVI, pp. 5353-54.

[319] Smialek Direct, pp. 3-4; Hearing Tr. Vol. V, p. 1039 (Smialek Cross).

[320] RESA AFR, p. 96.

[321] Companies' Post Hearing Reply Brief, pp. 237-242.

witness Bennett admitted that: (1) he lacked a specific POR program to propose; (2) he had not determined what discount rate would be appropriate; (3) he had no proof that a POR program would benefit shopping in the Companies' territories; (4) he had no empirical evidence that the absence of POR is inhibiting competition in the Companies' service territories; (5) although a CRES provider cannot disconnect a customer, a CRES provider can drop a customer for nonpayment (making any assertion from RESA that POR is necessary unfounded); (6) 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; (7) RESA has not done any studies to show that POR increases shopping; and (8) he does not know of any CRES providers that have said that they would not enter a territory until a POR program is implemented.[322] Moreover, the Commission has previously rejected a POR program proposed by RESA in the Companies' ESP III case, Case No. 12-1230-EL-SSO, because there was no evidence showing that the absence of a POR program had inhibited competition.[323] Finally, the Companies have an equivalent alternative to a POR program arising out of a stipulation in *WPS Energy Services, Inc. and Green Mountain Energy Company v. FirstEnergy Corp., et al.*, Case No. 02-1944-EL-CSS. RESA has not demonstrated in this proceeding that a POR program would be beneficial to the Companies' customers, and there was no basis in this record to compel the Companies to add a POR program to Stipulated ESP IV. For that reason, the Commission's decision not to require a POR program in Stipulated ESP IV was not unreasonable or unlawful, and RESA's application for rehearing should be denied.

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[322] Hearing Tr. Vol. XXVI, pp. 5347-52 (Bennett Cross).

[323] Case No. 12-1230-EL-SSO, Opinion and Order, p. 41 (July 18, 2012).

P. The Commission's Order Permitting The Companies To Modify Rider NMB Is Not Unreasonable Or Unlawful.

In its Order, the Commission approved the Companies' request to modify existing Rider NMB to include certain non-market-based PJM billing line items. The Companies demonstrated that this will lower costs associated with the charges by having the Companies, rather than SSO suppliers and CRES providers, pay these items because it reduces the risk premium added by SSO suppliers and CRES providers.[324] OMAEG argues that the Commission failed to explain its rationale for permitting the Companies to modify Rider NMB.[325] RESA argues that the Commission "erred by failing to explicitly rule on the Stipulation to extend Rider NMB to include PJM item 1375 (Balancing Operating Reserve)."[326] OMAEG and RESA are wrong. The Commission cited to record evidence, which included the Companies' demonstration that modifying Rider NMB in this manner will lower costs.[327] OMAEG and RESA's applications for rehearing in this regard should be denied.

Without citing to record evidence, OMAEG next argues that the Commission's approval of the Rider NMB modifications is unreasonable and unlawful because it will increase costs to customers.[328] OMAEG's arguments are not new and should be rejected again on rehearing.[329] Moreover, OMAEG claims are incorrect. First, OMAEG's claim that RTO uplift charges are somehow related to providers purchase and hedging strategies (and that would transfer risk to

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[324] Order, p. 73.

[325] OMAEG AFR, p. 55.

[326] RESA AFR, pp. 93-95.

[327] RESA AFR, pp. 93-95.

[328] OMAEG AFR, pp. 54-56.

[329] OMAEG Initial Brief, pp. 15-17.

customers) was unsupported in the record, and is simply incorrect.[330] Uplift charges include costs incurred by PJM as a result of out-of-merit dispatch.[331] Such dispatch occurs when generation from a particular facility is needed for reliability purposes, including in emergency conditions.[332] When such conditions will occur, which resources will be dispatched and how much the cost of such dispatch will be are not knowable,[333] and, therefore, related uplift charges are unpredictable. Likewise, OMAEG's concern that the potential charges are vague and overbroad is unfounded. 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.[334]

Last, OMAEG's concerns about double billing (once by a CRES provider and once by the Companies) have been raised and rejected in previous ESPs.[335] 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

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[330] OMAEG AFR, p. 55.

[331] Hearing Tr. Vol. V, p. 982 (Stein Cross).

[332] Hearing Tr. Vol. V, p. 986 (Stein Cross).

[333] Hearing Tr. Vol. V, pp. 948-949 (Stein Cross).

[334] Hearing Tr. Vol. V, pp. 1003-1004 (Stein Cross).

[335] *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).

Companies instead of suppliers.[336] For all of those reasons, the Commission should reject OMAEG's application for rehearing on this issue.

Although it is unclear from RESA's application whether it is arguing that the Commission erred by permitting the Companies to modify Rider NMB to include Line Item 1375[337] or whether RESA simply wants the Commission to explicitly rule on this issue (which it did, as discussed above), RESA nevertheless fails to demonstrate how the Commission's decision is unreasonable or unlawful, and its arguments are not new.[338] The Commission had ample evidence to support its decision to approve the Companies' modification to Rider NMB. As explained by the Companies in their Initial and Reply Briefs,[339] Company witness Stein testified that 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 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.[340] He also demonstrated that each of the additional line items proposed for inclusion in Rider NMB met those criteria.[341]

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[336] Hearing Tr. Vol. XXXIV, p. 7023 (Mikkelsen Rebuttal Cross).

[337] It is also confusing whether RESA is including Line Item 1218 (Planning Period Congestion Uplift) as an item of error because it is not specifically listed in its assignment of error but argued in its application. Therefore, the Companies will address that argument as well.

[338] RESA Initial Brief, p. 16.

[339] Companies' Initial Post Hearing Brief, pp. 99-102; Companies' Post Hearing Reply Brief, pp. 244-247.

[340] Hearing Tr. Vol. V, pp. 941-42 (Stein Cross).

[341] *See* Hearing Tr. Vol. V, pp. 942-943, 946-947, 948-949 (Stein Cross).

Indeed, the line items that RESA argues that should be excluded from Rider NMB[342] exhibit characteristics that would merit them to be included in Rider NMB, based upon the four criteria explained by Mr. Stein. For example, the Planning Period Congestion Uplift charges that RESA seeks to exclude meet all of the criteria for *inclusion* in Rider NMB, *i.e.*, they are not marketable, controllable, predictable, or transferable.[343] In fact, Exelon witness Campbell specifically agreed that they are neither controllable nor predictable.[344]

Similarly, Balancing Operating Reserves charges and Balancing Operating Reserves for Load Response and Reactive Services charges are neither marketable, controllable, nor predictable.[345] RESA witness Bennett 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.[346] RESA does not cite to any record evidence for its proposition that "including Line Item 1375 in Rider NMB would improperly allow the load-serving entities to avoid their own market-based costs and make all FirstEnergy ratepayers directly responsibility [sic] for it." [347] These unsupported propositions are not record evidence and should be disregarded by the Commission on rehearing.[348] RESA and OMAEG have failed to demonstrate how the Commission's Order on this issue is unreasonable and unlawful, and their AFRs should be denied.

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[342] RESA AFR, p. 94.

[343] Hearing Tr. Vol. V, pp. 942-43 (Stein Cross).

[344] Hearing Tr. Vol. XXVI, pp. 5255-56 (Campbell Cross). *See* Company Ex. 107, Customer Guide to PJM Billing.

[345] Hearing Tr. Vol. V, pp. 946-47, 948-49 (Stein Cross).

[346] Hearing Tr. Vol. XXVI, pp. 5346-5347 (Bennett Cross).

[347] RESA AFR, p. 94.

[348] *See, e.g., In re Application of Ormet Primary Aluminum Corporation for Approval of a Unique Arrangement with Ohio Power Company and Columbus Southern Power Company*, Case No. 09-119-EL-AEC, Entry on Rehearing, p. 10 (September 15, 2009).

Q. The Commission's Order Approving the Rider NMB Pilot Program Is Not Unreasonable or Unlawful.

In its Order, the Commission approved the Companies' Rider NMB Pilot Program finding that the pilot "provides the opportunity to determine if industrial customers can obtain substantial savings by obtaining certain transmission services outside of Rider NMB without imposing significant costs on other customers[,] will provide better price signals to industrial customers and promote job retention and economic develop in this region[, and] should facilitate the state's effectiveness in the global economy in accordance with R.C. 4298.02(N)."[349]

RESA and OMAEG assert that the Rider NMB Pilot Program is unduly limiting, discriminatory, and unjust because it applies to only certain customers.[350] They also assert that the pilot program violates state policy in that regard. However, as the Ohio Supreme Court stated in *In re Columbus S. Power Co.*, 128 Ohio St. 3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 62, the policies in R.C. 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 the pilot program conflicted with R.C. 4928.02(A) (which it does not), the Commission has authority to approve it.

For its part, RESA replicates the exact same arguments on rehearing that it made in its Initial Brief.[351] These arguments are not new, and the Commission already rejected them.[352] As

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[349] Order, p. 94.

[350] RESA AFR, pp. 96-100; OMAEG, pp. 57-60.

[351] RESA Initial Brief, pp. 49-51.

[352] Order, p. 112.

these arguments are not new, the Commission should reject them again. Nevertheless, in an effort to bolster its argument, RESA asserts several "concerns" that were not in evidence in the record, namely that the Companies would not have access to certain information to determine if customers are benefitting from the pilot program.[353] None of these "concerns" are supported by the record and should be disregarded on rehearing.[354]

Like RESA, OMAEG makes several claims that are simply not presented in the record. For example, OMAEG claims that "interested customers are excluded from participation simply because they did not sign the Stipulation (or be a named non-opposing party)."[355] OMAEG also complains, on one hand, that the pilot program limits customers, but, on the other hand, complains that the pilot program is not designed in a way "to keep the number of participants manageable."[356] OMAEG also speculates, without any record evidence, that "[t]he specific named parties who are permitted to participate in the pilot program per the Stipulation may use their exclusive participation to lure other customers to become members of their organizations given the Stipulation does not limit participation to those customers who were members at the time the Stipulation was executed as explained above."[357] Because none of these clams are supported by record evidence, the Commission should likewise ignore them on rehearing.

Put simply, RESA and OMAEG have failed to demonstrate that the Commission's approval of the Rider NMB Pilot Program is unreasonable or unlawful. As the Commission

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[353] RESA AFR, p. 99.

[354] *See, e.g., In re Application of Ormet Primary Aluminum Corporation for Approval of a Unique Arrangement with Ohio Power Company and Columbus Southern Power Company*, Case No. 09-119-EL-AEC, Entry on Rehearing, p. 10 (September 15, 2009).

[355] OMAEG AFR, p. 57.

[356] OMAEG AFR, p. 59.

[357] OMAEG AFR, p. 60.

found, the pilot program is not discriminatory as "[t]he nature of any pilot program is to keep the number of participants manageable in order to make some determination of the efficacy of the program being tested."[358] 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. The Companies demonstrated that through the Rider NMB Opt-Out Pilot Program, they seek to study administrative burdens and costs of giving customers the option to have their CRES providers pay Rider NMB charges.[359] Similarly, the Companies also demonstrated that they seek to determine whether such an option provides benefits to both participating and nonparticipating customers.[360] Moreover, as the Commission found, "the Third Supplemental Stipulation expanded the number of potential participants in the pilot program."[361]

RESA asserts that a pilot program should contain four elements. Yet RESA failed to provide any support or precedent for its suggested components. Thus, the Commission properly rejected these suggestions. Further, RESA witness Bennett admitted that a CRES provider is not required to provide an NMB product to pilot participants.[362] In addition, Mr. Bennett agreed that the way PJM allocates these non-market based costs under the pilot would not change.[363]

RESA also fails to recognize both how NMB costs are currently allocated and how NMB costs would be allocated under the pilot. Ms. Mikkelsen testified that over 99% of charges in Rider NMB are allocated by NSPL. She stated, "[t]o the extent that a customer participates in the pilot, they leave the companies' NMB service, and they are going to – their service provider,

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[358] Order, p. 112.

[359] Supp. Stip., pp. 3-5; Mikkelsen Third Supp., p. 2; Hearing Tr. Vol. II, p. 470 (Mikkelsen Cross).

[360] Supp. Stip., pp. 3-5; Hearing Tr. Vol. II, pp. 670-71 (Mikkelsen Cross).

[361] Order, p. 112.

[362] Hearing Tr. Vol. XXVI, p. 5357 (Bennett Cross).

[363] Hearing Tr. Vol. XXVI, p. 5358 (Bennett Cross).

CRES provider, will be assigned those costs on the basis of their NSPL, and the costs assigned to the company will go down accordingly."[364] OCC witness Rubin admitted on cross-examination 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.[365] 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 properly approved the Rider NMB Pilot Program. For those reasons, the Commission should deny OMAEG and RESA's applications for rehearing.

R. The Commission's Order Approving The HLF/TOU Pilot Program Is Not Unreasonable Or Unlawful.

Finding that the HLF/TOU pilot program "provides an incentive for large retailers to retain or relocate their corporate headquarter to this state" and "fits squarely under Ohio policy [R.C. 4928.02(D)], which encourages innovation and market access for cost-effective retail electric service, including demand-side management and time-differentiated pricing,"[366] the Commission properly approved the HLF/TOU Pilot Program. RESA disagrees, arguing that the pilot program is unduly discriminatory and will not benefit the public interest.[367] RESA made this same argument in its Initial Brief,[368] which was already considered by the Commission,[369] and it should be rejected again.

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[364] Hearing Tr. Vol. III, pp. 633, 642 (Mikkelsen Cross)

[365] Hearing Tr. Vol. XXIII, pp. 4807-4810 (Rubin Cross)

[366] Order, p. 94.

[367] RESA AFR, pp. 100-102.

[368] RESA Initial Brief, pp. 51-53.

[369] Order, p. 112.

For example, RESA mischaracterizes the Companies' testimony. Attempting to discount the importance of a "homogenous participant pool" RESA alleges that there is no reason for that participant pool.[370] 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.[371]

RESA has expressed further concern regarding the ability of a customer "to remain on the pilot even if their qualifications lapse"[372] and stated that as a result of this "loophole," for which RESA claims the Companies provided no explanation, there is "no apparent reason that it benefits ratepayers or the public interest."[373] RESA's concern reveals 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"[374] 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.[375] 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 for that by disqualifying them for that rate."[376] Thus, it is reasonable for participating customers who improve their consumption to stay in the program.

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[370] RESA AFR, p. 101.

[371] Hearing Tr. Vol. II, pp. 463-467 (Mikkelsen Cross); Mikkelsen Rebuttal, p. 17; Hearing Tr. Vol. II, pp. 290-291 (Mikkelsen Cross).

[372] RESA AFR, p. 101.

[373] RESA AFR, p. 101.

[374] Hearing Tr. Vol. II, p. 286 (Mikkelsen cross).

[375] Hearing Tr. Vol. XXXIV, pp. 7097-7098 (Mikkelsen Cross).

[376] Hearing Tr. Vol. II, p. 291 (Mikkelsen Cross).

RESA also claims that the rate design the Companies presented was inadequate for the Commission to approve the program. Curiously, RESA cites to Mr. Bennett's testimony that there was "scant" information provided regarding the HLF/TOU pilot program.[377] RESA's use of Mr. Bennett's testimony for this purpose is misplaced considering Mr. Bennett did not even review the attachment that contained the rate design for the HLF/TOU pilot program.[378] Given that RESA has not presented any reliable evidence in the record to support this argument, the Commission should reject it. RESA's application for rehearing on this issue should be denied.

S. The Commission's Order Approving The Resource Diversification Provisions Of Stipulated ESP IV Is Not Unreasonable Or Unlawful.

OMAEG argues that the Commission erred in approving provisions in Stipulated ESP IV related to CO_2 reduction, battery technology investment, energy efficiency, and renewable resources ("Resource Diversification Provisions") because they are not firm commitments and do not benefit the public interest[379] – an argument that is identical to one made in its Initial Brief and should be rejected.[380] EPSA and RESA make similar arguments.[381] None of these parties have demonstrated how the Commission's Order related to the Resource Diversification Provisions is unreasonable or unlawful.

The Commission properly found that the Resource Diversification Provisions of Stipulated ESP IV provide numerous benefits that further advance state policy enshrined in R.C. 4928.02.[382] As discussed in the Companies' Initial Brief and Reply Brief, the Companies in

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[377] RESA AFR, p. 101.

[378] Hearing. Tr. Vol. XXVI, pp. 5358-5359 (Bennett Cross).

[379] OMAEG AFR, pp. 15-17.

[380] OMAEG Initial Brief, pp. 89-90.

[381] EPSA AFR, pp. 39-40; RESA AFR, pp. 43-44. Indeed, RESA and EPSA's applications for rehearing are identical.

[382] Order, p. 118.

Stipulated ESP IV made a significant commitment to implement resource diversification initiatives.[383] OMAEG, RESA, and EPSA 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 their parent company FirstEnergy Corp.) made commitments that, as outlined below, are beneficial to customers and that are otherwise not obligatory. Moreover, as the Commission properly found, the Resource Diversification Provisions of the Third Supplemental Stipulation promote a number of state policies expressed in R.C. 4928.02.[384] 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.

With respect to the CO_2 reduction, 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 four years through 2045.[385] FirstEnergy Corp. and its affiliates are in fact making a commitment; a commitment that they had no obligation to provide as neither FirstEnergy Corp. nor FES are subject to the jurisdiction of the Commission.[386] Yet they have committed to meet ambitious CO_2 reduction goals that they have no legal obligation to undertake. Thus, the CO_2 carbon reduction goal contributes value to Stipulated ESP IV and does not violate any important regulatory principle or practice.

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[383] Companies' Initial Post Hearing Brief, p. 7; Companies' Post Hearing Reply Brief, pp. 256-65.

[384] *See* R.C. 4928.02(A), (C), D), (E) ad (J).

[385] Hearing Tr. Vol. XXXVI, pp. 7634-35, 7644-45 (Mikkelsen Cross); Order, p. 97 (changing filing from every five years to every four years).

[386] Sierra Club Initial Post-Hearing Brief, p. 119.

With respect to battery resources, the Companies will evaluate investing in battery resources and technology contingent upon Commission approval of cost recovery for such investments.[387] 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.[388] Given this lack of battery storage, it is important for customers that this technology be evaluated for future investments. The Companies 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.[389] This evaluation will not cost customers anything until a project is actually approved by the Commission and implemented.

With respect to the renewable resources provision in Section V.E.4. of the Third Supplemental Stipulation, if triggered, the Companies will file for approval to procure the requisite renewable energy. This particular 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.[390] Moreover, 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

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[387] Third Supp. Stip., Section V.E.2; Hearing Tr. Vol. XXXVII, pp. 7775-76 (Mikkelsen Cross).

[388] Grid Energy Storage, U.S .Department of Energy, December 2013, p. 11 administratively noticed in Hearing Tr. XL, pp. 8468-69.

[389] Hearing Tr. XXXVII, p. 7776 (Mikkelsen Cross).

[390] Hearing Tr. Vol. XXXVIII, pp. 8184-85 (Rabago Cross).

Companies are currently not legally obligated to do.[391] As Ms. Mikkelsen testified, "[o]nce the staff asks the Companies, they are obligated to file."[392]

Finally, with respect to energy efficiency provisions, OMAEG argues that the Companies already are legally obligated to meet statutory mandates, making this provision not beneficial. However, OMAEG fails to recognize that the Companies are not required to exceed those statutory mandates – but have agreed to do so here, which will further public policy as outlined in R.C. 4928.02. OCC makes the nonsensical argument that because the General Assembly in S.B. 310 froze energy efficiency and renewable mandates (for 2015 and 2016 only), the Commission's decision that energy efficiency benefits the public interest runs counter to the General Assembly.[393] This argument does not make sense because, as of January 1, 2017, there is no such freeze absent further legislation. Further, OCC does not demonstrate how approving goals in excess of statutory mandates is unreasonable or unlawful.

The Commission's Order approving the Resource Diversification Provisions is supported by ample evidence. OMAEG, RESA, EPSA and OCC have failed to demonstrate how the Order is unreasonable or unlawful, and their Applications for Rehearing should be denied.

T. The Commission Did Not Erroneously Fail To Address ELPC's Lost Distribution Revenue Arguments.

ELPC argued in post-hearing briefing that the Commission should not approve the Companies' request to recover lost distribution revenues from the Customer Action Program ("CAP").[394] Again, without citing to any authority, ELPC argues that the Commission unreasonably failed to address this issue because it did not rule on "whether this aspect of the

[391] Hearing Tr. Vol. XXXVI, p. 7540 (Mikkelsen Cross).

[392] Hearing Tr. Vol. XXXVI, p. 7543 (Mikkelsen Cross).

[393] OCC AFR, pp. 47-48.

[394] ELPC Initial Brief, pp. 59-60.

Stipulated ESP is consistent with existing regulatory principles."[395] However, the Commission did expressly address this issue and found:

> FirstEnergy also addresses the Environmental Groups, argument that the Companies should not be permitted to receive lost-distribution revenue tied to the Customer Action Program under Commission precedent. FirstEnergy argues that this provision is an integral part of the Stipulated ESP IV that is supported by all signatory parties, and that the Customer Action Program is an energy efficiency program authorized by R.C. 4928.662 and is contained in the Companies' Commission-approved EE/PDR Portfolio Plan. *In re FirstEnergy*, Case No. 12-2190-EL-POR, Finding and Order (Nov. 20, 2014), pp. 8-9.[396]

The Commission need not do anything more on rehearing.

However, if the Commission wishes to provide further clarification, 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 R.C. 4928.662 contained in the Companies' Commission-approved EE/PDR Portfolio Plans.[397] 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 customer savings will give rise to lost distribution revenue.[398] In addition, similar to all other Commission-approved energy efficiency programs, savings arising from the CAP would also be subject to the same

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[395] ELPC AFR, p. 24.

[396] Order, p. 107.

[397] *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").

[398] Hearing Tr. Vol. III, p. 541 (Mikkelsen Cross).

measurement and verification protocols before any savings, which would lead to lost distribution revenues, may be counted.[399]

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 in this proceeding.[400] ELPC has not provided an adequate basis for the Commission to grant rehearing. First, the Commission's decisions relied upon by ELPC pre-date the enactment of S.B. 310. S.B. 310 specifically authorized the CAP.[401] Second, the only 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.[402] 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.[403] Because the CAP is an approved energy efficiency program specifically authorized by S.B. 310, and ELPC has not presented any evidence as to why this energy efficiency program should be treated differently from other approved energy efficiency programs, rehearing should be denied.

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[399] Hearing Tr. Vol. III, p. 559 (Mikkelsen Cross).

[400] 2014 EE/PDR Order, pp. 18-19.

[401] R.C. 4928.662(A).

[402] *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".

[403] *See* 2011 EE/PDR Order, p. 21.

U. The Commission's Order Approving the Cap on Shared Savings Is Not Unreasonable or Unlawful.

In its Opinion, the Commission approved the cap on shared savings contained in Stipulated ESP IV, finding that:

> We note that shared savings are the result of the Companies exceeding the statutory mandates for energy efficiency. The current cap of $10 million was set only for the purposes of the Companies' three-year program portfolio plan for 2014 through 2016; thus, the Commission made no ruling on the appropriate cap for 2017 and beyond. At that time, the Commission noted that the cap could be increased from $10 million to $20 million if the Companies implemented a decoupling mechanism. The Companies have now committed to file an application to implement a decoupling mechanism in the form of SFV rate design.
>
> Further, as discussed by Company witness Mikkelsen, any programs eligible for shared savings must be cost-effective; thus the Companies only earn shared savings if they implement cost-effective energy efficiency programs that produce energy savings in excess of the statutory mandates (Tr. Vol. XXXVI at 7639). We find, therefore, that the increase in the shared savings cap is in the public interest because it encourages the Companies to seek to provide to their customers all available cost-effective energy efficiency opportunities. As the Commission has previously stated "because * * * energy savings must be cost-effective, by definition, customers in the aggregate save money when the Companies deliver energy savings opportunities to their customers instead of energy. To the extent the Companies accelerate the delivery of cost-effective energy savings opportunities to their customers, they will also accelerate the net cost savings which customers enjoy. Thus every kWh of energy that can be displaced through cost-effective energy efficiency programs is a savings, not a cost, to the Companies' customers." *In re Application of FirstEnergy*, Case No. 09-1947-EL-POR, et al. Entry on Rehearing (Sep. 7, 2011), p. 6.[404]

Without explaining how these provisions are unreasonable or unlawful, ELPC argues that the Commission's conclusions failed to account for the current state of Ohio law, namely that the

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[404] Order, p. 95.

Companies can count savings: 1) from customer actions (or CAP); and 2) on a gross basis.[405] ELPC's arguments that the Commission failed to consider these two issues is without merit, as is its unsubstantiated statement that "[t]his means the FirstEnergy Utilities may be able to earn shared savings up to the new cap simply by diverting resources to expanding the scope of the Customer Action Program or other programs in areas where customers are already independently adopting more efficient technologies and behaviors."[406] ELPC is incorrect on the first point as the Commission clearly took into consideration that the Companies would count shared savings from cost-effective programs, such as the CAP program, because the Commission directly cited it as an argument that ELPC made in its Order.[407]

As it relates to counting savings on a gross basis, the Commission previously authorized the Companies (*i.e.*, prior to the enactment of R.C. 4928.662(D)) to count savings on a gross basis, which has been the practice even prior to S.B. 310.[408] Thus, when the Commission previously approved the Companies' shared savings mechanism in Case No. 12-2190-EL-POR, as discussed in its Order above, the Commission considered the fact that the Companies count savings on a gross basis and did so here. Therefore, the Commission should deny ELPC's application for rehearing on this issue.

Next, ELPC argues that the Commission unreasonably relied on its decision in an earlier AEP Portfolio Plan proceeding, Case No. 11-5568-EL-POR (the "*AEP Portfolio Case*"), in approving the shared savings cap and incorrectly asserts that the Commission "primarily" relied on its prior approval of the Companies' shared savings mechanism in Case No. 12-2190-EL-

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[405] ELPC AFR, p. 16.

[406] ELPC AFR, p. 18.

[407] Order, pp. 68-69.

[408] *In the Matter of Protocols for the Measurement and Verification of Energy Efficiency and Peak Demand Reduction Measures,* Case No. 09-512, Finding and Order, p. 5 (Oct. 15, 2009).

POR.[409] As is apparent from the Order, the Commission did not "primarily" rely on its previous order, but rather relied upon the Companies' evidence and policy considerations in approving the shared savings cap here. Second, the Commission did not rely on the *AEP Portfolio Case* as an identical case to the Companies' commitment to the decoupling proceeding in Stipulated ESP IV. Rather, in Case No. 12-2190-EL-POR, the Commission found that "should FirstEnergy decouple distribution usage from usage in the future," an increase in shared savings was warranted. In this case, the Companies have committed to filing an application to implement a specific straight fixed variable ("SFV") rate design starting January 1, 2019.[410] In light of that simultaneous commitment, the Commission properly increased the cap in accordance with its previous order in Case No. 12-2190-EL-POR.

Third, AEP's "pilot" decoupling program and the Companies' commitment in the Stipulated ESP IV regarding an SFV rate design are not as drastically different as ELPC's claim. When AEP received approval of its pilot program in December 14, 2011, there was no "certainty" as ELPC argues[411] because the Commission clearly required further review of the pilot program, just as the Companies here will file a separate proceeding to review the SFV rate design.[412]

Fourth, ELPC's assertion that the shared savings cap and SFV rate design have to be synchronized is unfounded because, as discussed above, the Commission approved the cap for reasons other than its previous orders.

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[409] ELPC AFR, p. 18.

[410] Rubin Supp., pp. 3-5.

[411] ELPC AFR, p. 19.

[412] *In re Columbus Southern Power Co. and Ohio Power Co.*, Case No. 11-351-EL-AIR, *et al.*, Opinion and Order at 10 (Dec. 14, 2011).

Fifth, ELPC's argument that the cap is not justified because the AEP decoupling pilot and the Companies' proposed SFV rate design are materially different is unfounded, especially in light of the Commission's statement when approving AEP's pilot program that the SFV rate design may be more appropriate.[413]

Finally, in Case No. 12-2190-EL-POR, the Commission, in determining the appropriate amount of shared savings, balanced the fact that the Companies collected lost distribution revenue while AEP had a decoupling mechanism, finding that a lower cap was appropriate for the Companies.[414] Here, the Commission conducted the same balancing test, finding that an increased cap was appropriate in light of the Companies' foregoing of certain lost distribution revenue as part of its potential decoupling provision while also considering the need to increase incentives to exceed statutory EE/PDR mandates.

Moreover, ELPC's criticism that AEP should be treated differently because it chose to forego all lost distribution has already been rejected by the Commission:

> We reject the Environmental Advocates' contention that AEP-Ohio merits higher incentive levels because FirstEnergy collects lost distribution mechanism while AEP-Ohio does not collect lost distribution revenue from residential and small commercial customers. Pursuant to the stipulation approved by the Commission in its last distribution rate case, AEP-Ohio has agreed to implement a throughput balancing adjustment rider on a pilot basis for residential and small commercial customers. In re Columbus Southern Power Company and Ohio Power Company, Case Nos. 11-351-El-AIR et al. Opinion and Order (December 14, 2011) at 7, 9-10. Although this rider may be the Environmental Advocates' preferred mechanism for decoupling distribution revenue from usage and removing any disincentive to the utility to

[413] Rábago Direct, pp. 17-18.

[414] Case No. 12-2190, Opinion and Order, p. 16 (Mar. 20, 2012).

> promote energy efficiency programs, the rider also effectively negates any need for the collection of lost distribution revenue.[415]

Last, ELPC asserts that the Companies failed to provide evidence to support the increase in the shared savings cap, asserting that this issue should be determined in the Companies' 2017-2019 EE/PDR portfolio plan case, Case No. 16-743-EL-POR.[416] As the Commission's Order indicates, the increase in the shared savings cap is supported by the record. The Companies are eligible for shared savings only for energy efficiency savings achieved in excess of the statutory benchmarks and only for cost-effective programs.[417] And an increase in the savings cap to $25 million for the Companies is reasonable given that it, 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.[418] Indeed, ELPC's witness recognized that shared savings programs are commonly used and can have value.[419] ELPC ignores that additional savings achieved by the Companies above the existing $10 million cap means that the Companies' customers achieve substantially more savings. 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.[420] For all of those reasons, the Commission should deny ELPC's application for rehearing on this issue.

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[415] *In the Matter of [the Companies'] Application for Approval of Their Energy Efficiency and Peak Demand Reduction Portfolio Plans*, Case Nos. 12-2190-EL-POR, Opinion and Order, p. 15. (Mar. 20, 2013.)

[416] ELPC AFR, pp. 17, 23.

[417] Third Supp. Stip., Section V.E.3.d.; Hearing Tr. Vol. XXXVI, p. 7639 (Mikkelsen Cross).

[418] Case No. 11-5568-EL-POR, Finding and Order, p. 8 (Mar. 21, 2012).

[419] Hearing Tr. Vol. XXXVIII, pp. 8183-84 (Rabago Cross).

[420] *See* Case No. 12-2190-EL-POR, *et al.*, Opinion and Order, p. 13 (Mar. 20, 2013).

V. The Commission Did Not Err In Finding That The Grid Modernization Provisions Of Stipulated ESP IV Would Benefit The Public Interest.

Making identical arguments in its Initial Brief,[421] OCC argues that the Commission erred in finding that the grid modernization provisions of Stipulated ESP IV would benefit the public interest.[422] As these arguments are not new, rehearing should be denied.

OCC also asserts that the Commission's finding is not supported by record evidence.[423] OCC is wrong. In its Order, the Commission cited to the evidence presented by the Companies.[424] The Commission also noted that:

> Ohio policy supports innovation through the implementation of smart grid programs and advanced metering infrastructure. R.C. 4928.02(D). Further, modernizing the grid in the Companies' service territories is also consistent with efforts to make the grid more reliable and cost effective for consumers. Further, advanced metering associated with grid modernization will promote competition by facilitating the offering by competitive suppliers of innovative products to meet customers' needs. We encourage the Companies to ensure that the proposed grid modernization filing considers the future transition to a grid that engages customers and supports flexibility in meeting resource adequacy needs.[425]

This is ample evidence to support the Commission's decision.

Finally, OCC's arguments to the contrary are misplaced. The Companies are not legally obligated to file such a plan; Staff specifically testified that it wanted the Companies to file this plan.[426] Moreover, the promotion of smart grid and advanced metering infrastructure initiatives

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[421] OCC/NOAC Initial Brief, pp. 153-155.

[422] OCC/NOAC AFR, pp. 25-27.

[423] OCC/NOAC AFR, p. 26.

[424] Order, p. 69.

[425] Order, pp. 95-96.

[426] Benedict Direct, pp. 2-3.

is a specifically enumerated State policy.[427] OCC criticizes the Companies for not providing precise details in this case regarding the business plan. 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."[428] The anticipated business plan will address multiple potential initiatives and include a timeline for the Companies to achieve full smart meter implementation.[429] As Ms. Mikkelsen testified and as 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.[430]

OCC also criticizes the return on equity ("ROE") for grid modernization established by the Third Supplemental Stipulation. However, 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.[431] The ROE will be adjusted as ATSI's ROE is adjusted in the future.[432] All Signatory Parties agreed that this ROE formula is appropriate to incent grid modernization

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[427] R.C. 4928.02(D).

[428] Third Supp. Stip., Section V.D.1.

[429] Third Supp. Stip., Section V.D.2; Hearing Tr. Vol. XXXVI, p. 7628 (Mikkelsen Cross) (business plan will include smart meter budget).

[430] Hearing Tr. Vol. XXXVI, p. 7624 (Mikkelsen Cross).

[431] Third Supp. Stip., Section V.D.3.; Hearing Tr. Vol. XXXVI, pp. 7631-32 (Mikkelsen Cross).

[432] Third Supp. Stip., Section V.D.3.; Hearing Tr. Vol. XXXVII, p. 7775 (Mikkelsen Cross).

investment in Ohio over other potential investments.[433] 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.[434] Thus, OCC's arguments should be rejected, and its AFR should be denied.

IV. STIPULATED ESP IV DOES NOT VIOLATE ANY IMPORTANT REGULATORY PRINCIPLE OR PRACTICE.

A. Rider RRS Is Authorized By R.C. 4928.143(B)(2)(d).

The Commission correctly found that Rider RRS met the three requirements of R.C. 4928.143(B)(2)(d).[435] On rehearing, intervenors have reiterated arguments which have already been made and rejected by the Commission. Each is discussed briefly below, and each lacks merit.

1. Rider RRS is a term, condition or charge.

Rider RRS is clearly a term, condition, or charge. Some intervenors expressly admit this, while others merely do not take issue with this prong of the analysis.[436] However, one related group of intervenors claim that Rider RRS is not a "charge" because it is projected to be a credit over the term of the ESP and the statute never mentions the word "credit."[437] As correctly stated in the Order, this argument is overly restrictive. Rider RRS is projected to appear as a charge on customer bills in at least the first two years of the ESP, and therefore meets the plain language of

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[433] Hearing Tr. Vol. XXXVII, p. 7775 (Mikkelsen Cross).

[434] Third Supp. Stip., Section V.D.3.

[435] Order, p. 108.

[436] *See, e.g.*, CMSD AFR, p. 8 ("Although CMSD does not dispute that Rider RRS is a charge. . .")

[437] Dynegy AFR, p. 6; RESA AFR, p. 14; EPSA AFR, pp. 10-12.

the statute.[438] There is no statutory requirement that Rider RRS be a net charge over the term of the rider, or that it be a charge in every year of the rider. Intervenors' attempt to add these requirements to the statute should be rejected.[439]

This argument also fails because this an overly restrictive reading of the word "charge." There is nothing in the statute indicating that a "charge" has to be a payment by customers. "Charges" can be positive or negative, the common use of the word "credit" is merely a convenient way to distinguish the two.

This argument also ignores that the statute is not limited to only "charges," and also permits "terms" and "conditions." Rider RRS is clearly both a term and condition of the ESP as well as a charge. Therefore, even if the overly restrictive reading of "charge" were adopted, then Rider RRS would still qualify under the statute.

2. Rider RRS relates to limitations on customer shopping for retail electric generation service, bypassability, and default service.

Several intervenors reiterated arguments which have already been extensively briefed by the parties. These arguments were all previously discussed and refuted by the Companies' Post-Hearing Reply Brief at pp. 269-72. In the interests of efficiency that discussion is hereby incorporated by reference, and is only briefly reiterated herein for the convenience of the Commission.

Some intervenors argue that Rider RRS does not relate to a financial limitation on customer shopping and that any limitation must be physical.[440] By arguing that "limitations on

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[438] Order, p. 108.

[439] *In re Application of Columbus S. Power Co.*, Slip Opinion No. 2016-Ohio-1608, ¶ 49 ("[I]n construing a statute, we may not add or delete words.").

[440] CMSD AFR, pp. 8-11; OCC/NOAC AFR, p. 34; Dynegy AFR, pp. 6-14; Sierra Club AFR, pp. 9-12; OMAEG AFR, pp. 21-22; RESA AFR, pp. 15-16; EPSA AFR, pp. 12-14; P4S AFR, pp. 4-5.

customer shopping" should be modified to read "***physical*** limitations on customers shopping," these parties are inappropriately attempting to add words to the statute in addition to those chosen by the General Assembly. This would violate the interpretational maxim that courts "must give effect to the words used, making neither additions nor deletions from words chosen by the General Assembly."[441] The Commission has already considered and rejected this argument.[442] The Commission held that Rider RRS constitutes a financial limitation on shopping that would help stabilize rates. "Rider RRS would function as a financial restraint on complete reliance on the retail market for the pricing of retail electric generation service." [443] As the Commission correctly determined, there is no reason to read the word "physical" into this statute, and a general term like "limitation" necessarily includes subcategories that constitute different types of limitations.

Other intervenors claim that even if financial limitations on shopping are considered, Rider RRS nevertheless should not be considered a financial limitation on shopping since it does not completely eliminate a customer's ability to shop.[444] The intervenors argue that because the rider does not **prohibit** customers from shopping it should not be considered a **limitation** on shopping. This is incorrect. There is a difference between operating as an express prohibition on shopping or restriction on physical generation supply (which Rider RRS is not) and acting as a limitation on shopping (which Rider RRS does).[445] The Commission correctly identified this difference in its Order. Moreover, this alleged complete prohibition does not appear in the

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[441] *In re Columbus Southern Power Co.*, 138 Ohio St.3d 448, 2014-Ohio-462, 8 N.E.3d 863, ¶ 26.

[442] Order, p. 109.

[443] Order, p. 109.

[444] RESA AFR, p. 22; EPSA AFR, pp. 15-16; CMSD AFR, p. 9-10; NOPEC AFR, p. 11.

[445] Order, p. 109 (discussing difference between physical limitations on shopping and functioning as a financial restraint).

statute. The statute requires only that there be a "limitation," not a complete prohibition. The intervenors' arguments are unsupported.

OCC asserts that the Commission failed to cite record evidence supporting this portion of its Order.[446] This is not correct. The Commission expressly cited precedent from the *AEP ESP3* Order and the *Duke ESP III* Order. The Commission then applied the statute and the precedent to the facts of this proceeding, which it discussed in great detail earlier in the Order. In fact, in the very paragraph addressing this argument, the Commission referenced the design of Rider RRS, how Rider RRS impacts shopping customers, and the projected generation credit over the term of the ESP.[447] The Commission clearly cited record evidence supporting its decision, and arguments to the contrary should be rejected.

3. Rider RRS would have the effect of stabilizing or providing certainty regarding retail electric service.

Several intervenors argue that Rider RRS is not related to stabilizing rates because there is no evidence that Rider RRS would move in the opposite direction of the market.[448] This is not correct. The minor difference between quarterly updates and annual forecasts would not cause Rider RRS to act contrary to the direction of the market in a significant way. Moreover, this argument has already been considered and rejected by the Commission. "If market prices for energy, capacity and ancillary services rise, Rider RRS will operate to mitigate the increase in market prices."[449] This is consistent with prior Commission precedent.[450]

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[446] OCC/NOAC AFR, p. 33.

[447] Order, p. 109.

[448] NOPEC AFR, p. 14; CMSD AFR, pp. 14-15; EPSA AFR, p. 70-71.

[449] Order, p. 109.

[450] *AEP ESP3* Order, p. 21; *Duke ESP4* Order, p. 44

Other intervenors argue that since the Commission has not found conclusively that Rider RRS would stabilize rates in each quarter, it fails to meet the requirements of the statute.[451] As noted in the Order and 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.[452] As Rider RRS has this design, the intervenor arguments lack merit.

NOPEC, OMAEG, and EPSA argue that laddering, staggering, or CRES contracts are enough to protect customers from rate fluctuations.[453] This argument misses the point. The Companies agree that laddering and staggering can mitigate price changes over the short term, and that SSO prices are less volatile than hourly wholesale prices. However, that is not the relevant question. The relevant question is whether Rider RRS has an **additional** stabilizing effect over and above those methods. Of course it does. Rider RRS provides a longer-term stabilizing effect that is actually projected to reduce customer bills over time, in addition to smoothing them out. Moreover, Rider RRS provides this longer-term stabilizing effect to all customers, not just customers taking SSO service. Therefore, Rider RRS meets the statutory criteria.

CMSD argues that if Rider RRS is a charge in any given period, it would not provide "stability" since it would be increasing the total price paid by customers.[454] CMSD's argument reads the word "charge" entirely out of the statute. What Division (B)(2)(d) contemplates is that customers pay a charge in exchange for more stable rates. In each year Rider RRS is a charge,

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[451] EPSA AFR, p. 66; OCC AFR, p. 36; CMSD AFR, pp. 11-12.

[452] *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.

[453] NOPEC AFR, pp. 13-14; EPSA AFR, pp. 14-16, 67-70; OMAEG AFR, p. 25.

[454] CMSD AFR, pp. 13-14.

customers continue to receive the benefit of low energy prices while also receiving price protection, reliability and resource diversity. Therefore, Rider RRS can simultaneously be both a charge and provide rate stability for customers.

B. Rider RRS Is Authorized By R.C. 4928.143(B)(2)(i).

The Commission held that the Economic Stability Program, of which Rider RRS is part, qualifies as an economic development program, and therefore is qualified under R.C. 4928.143(B)(2)(i).[455] On rehearing, OCC and CMSD claim Rider RRS does not meet the requirements of the statute because the Plants are owned by an affiliate of the Companies, and the statute addresses only programs by the "electric distribution utility."[456] This argument evidences a misunderstanding of the Economic Stability Program. The Companies are proposing the ESP. The ESP contains Rider RRS, which is an economic development provision. Accordingly, Rider RRS is a program proposed by the Companies, which meets the R.C. 4928.143(B)(2)(i) requirement for involvement of the distribution utility. This is consistent with well-established Commission precedent from past ESP cases were economic development programs involving third parties have been approved.[457]

CMSD also argues that Rider RRS is not an economic development "program" and is instead a rate.[458] CMSD offers no authority or analysis to support its claim that economic development rates "could not have been what the legislature had in mind."[459] CMSD's position is not only unsupported, it flies in the face of economic development programs throughout Ohio.

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[455] Order, pp. 109-10.

[456] OCC/NOAC AFR, p. 38; CMSD AFR, p. 18.

[457] *See* Companies' Post Hearing Reply Brief, pp. 275-76.

[458] CMSD AFR, p. 18.

[459] CMSD AFR, p. 17.

Reduced tax rates are often used for economic development purposes. Indeed, even at the Commission, reduced rates are often used in reasonable arrangements to spur economic activity in the state. As shown through those well-established programs in Ohio, rate discounts or similar tools are often used to spur economic development.

NOPEC, Sierra Club, P4S and Dynegy argue that the Commission's decision is flawed because the Commission assumed that the Plants would close if Rider RRS were not approved.[460] As a preliminary matter, there is nothing in the Order supporting this claim, as the Commission never said it assumed the Plants would close without Rider RRS.[461] More importantly, there is no statutory requirement that economic development programs only be used to keep facilities operational.

There is similarly no statutory language that supports Sierra Club's claim that the statute only authorizes certain types of programs. Instead, the statute grants broad discretion to the Commission to approve any programs relating to "economic development, job retention, and energy efficiency." This language gives broad discretion to the Commission because economic development programs 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. The Companies previously provided an extensive list of representative programs.[462] As shown through this Commission precedent, the intervenors' reading of the statute is unduly restrictive.

Dynegy, EPSA, and RESA assert a similar argument, claiming that Rider RRS is not a traditional economic development program and that the Companies presented Rider RRS as a

[460] NOPEC AFR, p. 15; Sierra Club AFR, p. 17; P4S AFR, p. 5; Dynegy AFR, p. 13.

[461] Order, p. 110.

[462] Companies' Post Hearing Reply Brief, p. 275-76.

rate stability mechanism rather than an economic development rider.[463] Again, this interpretation is overly restrictive and not supported by the statute. The statute does not require the only benefit of qualified programs be economic development. Indeed, one would imagine that the most effective economic development programs would serve multiple goals, such as providing jobs, a tax base, and community involvement. The broad nature of this authority is shown through Commission precedent, as the Commission has approved a wide range of economic development riders in the past.[464] Moreover, this argument is also factually incorrect. The Companies have presented the substantial economic benefits associated with Rider RRS from the inception of this case through the testimony of witnesses Murley, Mikkelsen, and Cunningham (among others). There is ample evidence in the record supporting the Commission's decision.

C. Rider RRS Does Not Conflict With R.C. 4928.02(H).

Many intervenors argue that Rider RRS constitutes a subsidy to FES.[465] This argument has already been considered and rejected by the Commission.[466] Moreover, in light of the Proposal discussed in Company witness Mikkelsen's Rehearing Testimony, these arguments are now moot and the Commission need not substantively address them.

To the extent the Commission wants to address these moot arguments, the Companies' Post-Hearing Reply Brief, at pages 277-80, provides three reasons why intervenors' arguments fail. First, R.C. 4928.143(B)(2) provides a list of nine items which can be included in an ESP. Any of these nine items may be included in an ESP "[n]otwithstanding any other provision of

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[463] Dynegy AFR, p. 13; EPSA AFR, p. 18; RESA AFR, p. 21.

[464] Companies' Post Hearing Reply Brief, p. 275-76.

[465] OCC/NOAC AFR, pp. 39, 45; NOPEC AFR, p. 18; ELPC AFR, pp. 3-12; OMAEG AFR, pp. 26-30; RESA AFR, pp. 10-13, 22-25, 77-81; EPSA AFR, pp. 7-9, 19-22.

[466] Order, p. 110.

Title XLIX of the Revised Code . . . ."[467] Thus, the Commission may approve Rider RRS as a component of the Companies' Stipulated ESP IV under R.C. 4928.143(B) notwithstanding any alleged conflict with R.C. 4928.02. Second, the policies in R.C. 4928.02 are guidelines, not requirements. The Ohio Supreme Court has held that these guidelines are not mandates to the Commission to take any specific action.[468] Third, Rider RRS is not a subsidy to FES, so R.C. 4928.02(H) does not apply.[469]

D. Rider RRS Does Not Conflict With R.C. 4928.03 Or With Ohio's Transition To Market-Based Generation Service Under S.B. 3.

RESA and EPSA claim that Rider RRS violates R.C. 4928.03 because retail electric service is "competitive" and that the Commission erred by failing to expressly address this argument.[470] They claim Rider RRS "requires shopping customers to pay for the affiliated generation of FES" and therefore departs from the General Assembly's directive to promote competition. This argument is moot in light of the Proposal since there will no longer be any contract with FES.

To the extent the Commission addresses this claim, it was previously addressed in detail[471] and is factually incorrect. It is undisputed that the output from the Plants will not be used to provide generation to customers.[472] While Rider RRS is a generation-related charge, it is not competitive retail electric generation service. Indeed, witnesses sponsored by EPSA and

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[467] R.C. 4928.143(B).

[468] *In re Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 62.

[469] *See* Companies' Post Hearing Reply Brief, pp. 278-80.

[470] RESA AFR, p. 26; EPSA AFR, pp. 7-10, 22-23.

[471] *See* Companies' Post Hearing Reply Brief, pp. 280-82.

[472] Hearing Tr. Vol. I, pp. 37-38 (Mikkelsen Cross).

Exelon admitted as much.[473] Thus, this statute is irrelevant because Rider RRS does not conflict with its language.

This argument is also incorrect as a matter of law. Nothing in R.C. 4928.03 (a remnant from S.B. 3) supersedes or contradicts the provisions of R.C. 4928.143 (from S.B. 221). R.C. 4928.03 does not prohibit charges to stabilize generation service pricing, and therefore these claims are invalid as a matter of law.

E. Rider RRS Does Not Violate R.C. 4905.22.

Dynegy, EPSA, and RESA argue that Rider RRS violates R.C. 4905.22 as an "unreasonable" charge and that the Commission erred by failing to expressly address this argument.[474] In brief, these parties argue the Commission should have adopted additional limitations on Rider RRS,[475] should not have approved a contract with an affiliate,[476] and the failure to adopt the recommended alternations was unreasonable and a violation of the statute.

These arguments fail because nothing in R.C. 4905.22 applies to retail rate stabilization charges authorized under R.C. 4928.143(B)(2)(d). A retail rate stabilization charge may be included in an ESP "notwithstanding any other provision of Title XLIX of the Revised Code," including R.C. 4905.22.[477]

Leaving aside the legal flaws in this position, the intervenors are merely seeking to substitute their judgment for the Commission's as to the advantages of Rider RRS. The Commission determined that these charges are reasonable. While intervenors may not agree

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[473] Hearing Tr. XXVI, p. 5202 (Campbell Cross); Hearing Tr. XXVIII, p. 5620 (Kalt Cross).

[474] Dynegy AFR, pp. 16-19; RESA AFR, p. 29; EPSA AFR, pp. 25-26.

[475] Dynegy AFR, pp. 16-19.

[476] Dynegy AFR, pp. 16-19; RESA AFR, p. 29; EPSA AFR, pp. 25-26.

[477] R.C. 4928.143(B).

with that determination, the Commission is more than justified in finding that a charge is just and reasonable because it protects retail customers from market risk and is projected to provide hundreds of millions of dollars of credits to customers. As such, R.C. 4905.22 does not apply.

F. Rider RRS Does Not Violate R.C. 4928.38.

Several intervenors argue that Rider RRS violates R.C. 4928.38's prohibition on the recovery of transition costs.[478] The Commission has already considered and rejected this argument, finding that there is no evidence Rider RRS would collect costs not recoverable in the competitive market.[479] There is also no reason to address this argument again because the Companies' Proposal renders it moot.

To the extent the Commission addresses this argument, the Commission should again reject it. The Companies are not attempting to recover pre-2001 generation costs through Rider RRS. OCC/NOPEC's witness Rose admitted that none of the stranded costs that existed in 2001 are on the books today.[480] Instead, the Companies are attempting to provide retail price stability to their customers. Thus, Rider RRS does not violate R.C. 4928.38. The Commission should reject this argument as it did in the Order and in several prior decisions.[481]

OCC/NOAC argue that a recent Ohio Supreme Court decision involving AEP Ohio is applicable because the statute includes both transition costs and "any equivalent revenues."[482] In that case, AEP Ohio's RSR had two components: a deferral part that recovered capacity costs, and a nondeferral part that recovered sufficient revenue to maintain AEP's financial integrity

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[478] OCC/NOAC AFR, pp. 28-30; RESA AFR, pp. 89-90; EPSA AFR, pp. 83-84; P4S AFR, pp. 9-10.

[479] Order, p. 112.

[480] Hearing Tr. Vol. XXVI, p. 5391 (K. Rose Cross).

[481] 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).

[482] OCC/NOAC AFR, pp. 29-30 (citing *In re Application of Columbus S. Power Co.*, 2016-Ohio-1608).

using an annual revenue target of $826 million. The Court noted that the Commission specifically tied the RSR to transitioning AEP to the competitive market.[483] The Court determined that AEP could recover its actual capacity costs of approximately $189/MW-day, but not amounts in excess of its actual costs.[484] Thus, to the extent the nondeferral part of RRS recovered capacity costs, those excess amounts were "unlawful transition revenues."[485]

The AEP Ohio decision is not analogous for several reasons. The Commission tied AEP's RSR to transitioning more rapidly to market-based pricing. The Court did not address the cost-based portion of AEP Ohio's charge, but instead limited its decision to the nondeferral portion of the charge tied to transitioning AEP to market. In contrast, Rider RRS is a hedge, not a financial integrity charge to transition the Companies to the competitive market.

The AEP Ohio decision is also not analogous because AEP Ohio owned the generating plants used to provide SSO supply. As the Commission's decision was expressly based on transitioning AEP Ohio to the competitive market, the Court considered the charge "equivalent to" transition revenue. Here, that is not the factual situation. The Companies divested their generation assets years ago. Modified Rider RRS is not based on the actual performance of the Plants, and it does not transfer revenue to FES to recover Plant costs. Moreover, the Companies have at no time in Stipulated ESP IV asked to recover plant costs as a trade-off for transitioning SSO service to market-based pricing.

Finally, the Court determined that AEP Ohio had waived the basic legal argument that the "notwithstanding" language in R.C. 4928.143(B) renders R.C. 4928.38 irrelevant for

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483 *In re Application of Columbus S. Power Co.*, 2016-Ohio-1608, ¶ 23.

484 *In re Application of Columbus S. Power Co.*, 2016-Ohio-1608, ¶ 33.

485 *In re Application of Columbus S. Power Co.*, 2016-Ohio-1608, ¶ 32.

purposes of an ESP proceeding.[486] R.C. 4928.143(B) specifically states that its provisions apply "notwithstanding" any provision of the Revised Code except certain specified statutes. As R.C. 4928.38 is not one of those statutes, the Court's determination is highly relevant. Chief Justice O'Connor and Justice Lanzinger's partial dissent explained how relevant: "But in doing so, the majority ignores what could be significant language in the ESP statute, R.C. 4928.143(B), by relegating that language to a footnote and then ignoring it. Majority Opinion at fn. 3."[487] This language is significant because "the word 'notwithstanding' could render R.C. 4928.38 inapplicable if the revenues are recoverable under one of the many provisions of R.C. 4928.143(B)(2)."[488] Those Justices found that language so significant they recommended remand to the Commission on this issue even though the Commission did not rely on this language in its order and AEP Ohio did not make the argument.[489] As the Court did not address this essential statutory language, the AEP Ohio decision is not dispositive of the Companies' Application.

G. Rider RRS Does Not Violate R.C. 4928.20(K).

NOPEC reiterates its argument that the Commission violated R.C. 4928.20(K) since it failed to consider the impact of Rider RRS on large-scale governmental aggregation.[490] This

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[486] *In re Application of Columbus S. Power Co*., 2016-Ohio-1608, ¶ 38, fn. 3 ("The '[n]otwithstanding' provision can be read as creating an exception to the prohibition against transition revenue. But because the commission did not rely on this language in the case below, and no party appears to have raised the issue, we decline to consider it on appeal.")

[487] *In re Application of Columbus S. Power Co*., 2016-Ohio-1608, ¶ 74.

[488] *In re Application of Columbus S. Power Co*., 2016-Ohio-1608, ¶ 76.

[489] *In re Application of Columbus S. Power Co*., 2016-Ohio-1608, ¶ 79.

[490] NOPEC AFR, pp. 3-6.

argument is curious since NOPEC acknowledges that the Commission expressly addressed this argument in its Order.[491]

On a more detailed review, it does not appear that NOPEC is actually arguing that the Commission did not consider the impact of Rider RRS on government aggregation. Instead, NOPEC argues that it has previously negotiated good deals for customers, and, therefore, this proposal is not necessary to obtain a hedge for customers.[492] This argument was already briefed by the parties[493] and rejected by the Commission. In brief, NOPEC confuses a percent off PTC offer (which guarantees customers rates below a SSO rate which will fluctuate with the market) with a hedge against market price movements. The hedge against market price movements serves a different purpose for customers, one not covered by the NOPEC contract. The Commission recognized this in rejecting NOPEC's argument, and should not change that finding now.

H. Rider RRS Does Not Raise Any Code Of Conduct Issues.

Dynegy, RESA, and EPSA argued that Rider RRS may implicate R.C. 4928.17's corporate separation requirements.[494] These parties note that the Commission addressed this argument but did not expressly rule on it other than indirectly finding that Rider RRS was appropriate under Ohio law.

This argument has been previously briefed by the Companies[495] and addressed by the Commission,[496] so there is no need to reiterate these arguments again here. Moreover, this

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[491] Order, p. 102 (describing the NOPEC argument); *id.*, p. 110 (finding that Rider RRS is not anticompetitive and is consistent with state policy guidelines).

[492] NOPEC AFR, pp. 5-6. P4S makes a similar argument. *See* P4S AFR, pp. 2-3.

[493] Companies' Post Hearing Reply Brief, pp. 284-86.

[494] Dynegy AFR, pp. 14-16; RESA AFR, pp. 27-28; EPSA AFR, pp. 23-25.

[495] Companies' Post Hearing Reply Brief, pp. 113-16, 286-89.

argument is now moot under the Companies' Proposal. As there is no longer any interrelationship between FES and the Companies regarding Rider RRS, there is no further concern under R.C. 4928.17, and this argument should be rejected.

I. Rider RRS Does Not Violate The Uniform Depositary Act.

CMSD has reiterated its argument regarding the Ohio Uniform Depository Act ("OUDA"), arguing that though the Commission addressed this argument in the Order, the Commission did not explain its reasoning in sufficient detail to explain its position.[497]

CMSD claims that political subdivisions are prohibited by the OUDA from directly investing in hedging products. However, there is nothing in the OUDA which addresses, directly or indirectly, the Commission's authority to establish retail electric rates. To its credit, CMSD expressly acknowledges this in its brief. "CMSD does not intend to suggest that the OUDA controls Commission ratemaking decisions."[498] Instead, CMSD claims that the OUDA should be considered as a state policy and be generally considered by the Commission. The Commission has already done just that. The Order considered the OUDA claim along with other policy issues under R.C. 4928.02.[499] The Order concluded that Rider RRS was consistent with Ohio policy and rejected CMSD's claim. Because no new arguments or information have been presented, there is no reason for the Commission to change its conclusion.

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[496] Order, pp. 103, 105.

[497] CMSD AFR, pp. 26-28.

[498] CMSD AFR, p. 27.

[499] Order, p. 102.

J. Rider RRS Does Not Run Afoul Of Federal Law.

Several intervenors make claims that Rider RRS is somehow impacted by federal law issues.[500] Those arguments are all based on the assumption that there would be a PPA between the Companies and FES. The Commission has already addressed these unfounded arguments in detail.[501] Under the Companies' Proposal on rehearing there would be no such PPA, and so these arguments are moot. To the extent the Commission wishes to substantively address these arguments again, the Companies hereby incorporate their prior responses addressing these topics.[502]

K. PJM Does Not Have Exclusive Jurisdiction Over Reliability.

Dynegy reiterated its arguments that PJM has exclusive jurisdiction over reliability so it should not be an issue considered by the Commission.[503] This argument is moot in light of the Companies' Proposal. As the Commission is no longer being asked to opine as to the reliability benefits of specific plants it need not reach this issue.

This argument is also incorrect. As previously explained in detail,[504] PJM does not have the jurisdiction to direct generation construction. All it can do is indicate where there are overloads and identify a transmission solution.[505] On the other hand, the Commission has direct statutory direction requiring it to ensure reliable retail electric service for customers. "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

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[500] *See, e.g.*, CMSD AFR, pp. 21-25; OCC/NOAC AFR, pp. 40-43.

[501] Order, pp. 86-87, 112.

[502] Companies' Post Hearing Reply Brief, pp. 290-95.

[503] Dynegy AFR, p. 30.

[504] Companies' Post Hearing Reply Brief, pp. 193-95.

[505] Hearing Tr. Vol. XVI, p. 3329 (Phillips Cross).

electric service . . . ."[506] Finally, numerous intervenor witnesses admitted that the Commission has an interest in ensuring reliability.[507] In light of this clear statutory direction and the numerous intervenor admissions, there can be no dispute the Commission has authority to address reliability issues.

L. The Commission's Order Does Not Violate R.C. 4928.143(E).

NOPEC argues that the Commission erred by failing to comply with the R.C. 4928.143(E) requirement for a review of the ESP after four years because Riders RRS and DCR will continue for eight years regardless of the outcome of that review.[508] This is incorrect. The Order does not prejudge the results of the four-year review process in any way, and NOPEC cites no specific language in the Order which it claims is improper. In light of NOPEC's failure to identify any portion of the Order which is improper, its argument should be rejected.

In addition to being unsupported, NOPEC's argument is also incorrect. The Order does not violate the terms of this statute. The Commission instituted a rigorous review process for both Riders RRS and DCR, severability provisions, addressed capacity performance program issues, and expressly provided that Rider RRS would terminate if FirstEnergy's corporate headquarters moves.[509] Those provisions anticipated significant Commission oversight. The Order does not say the Commission will not conduct all appropriate statutory supervision over the ESP. In light of the extensive review procedures contained in the Order, it appears NOPEC

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[506] 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.").

[507] Companies' Post Hearing Reply Brief, p. 195.

[508] NOPEC AFR, p. 8.

[509] Order, pp. 89, 92, 97.

takes issue with the language of the statute itself. R.C. 4928.143(E) does not limit programs approved in an ESP to only four years. While NOPEC may wish that ESPs were limited to only a four-year term, that is not required by R.C. 4928.143(E). Instead, that statute only provides that the Commission will:

> "[D]etermine 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."

There is nothing in this language prohibiting the Commission from approving Riders like RRS and DCR, which will be in place for longer than four years. Accordingly, NOPEC's arguments lack statutory support.

M. The Terms Of Rider RRS Did Not Require A Heightened Standard Of Review.

ELPC and OMAEG argue that the Commission should have used a higher standard of review for Rider RRS since the rider involved a transaction with an affiliate of the Companies.[510] Neither of these parties cite any authority requiring the Commission to apply a heightened standard of review for this transaction. Instead, ELPC argues by analogy that Ohio's general policy supporting competition suggests a higher standard of review for affiliate transactions.[511] Similarly, OMAEG argues that because federal law supports a different standard for affiliate transactions, Ohio should also utilize a higher standard of review.[512] Each of these arguments is flawed because there is nothing in Ohio law which suggests there should be a different standard

[510] ELPC AFR, pp. 12-16; OMAEG AFR, pp. 30-31.

[511] ELPC AFR, pp. 14-16 (relying on 4928.02(A)).

[512] OMAEG AFR, pp. 30-31.

of review for Rider RRS than that already used by the Commission. However, the Commission need not reach this issue because these arguments are moot under the Companies' Proposal.

N. The Commission Used The Correct Standard of Review.

Sierra Club claims that the Commission used an incorrect standard of review.[513] Sierra Club offers no evidence or analysis suggesting any specific area where the Commission applied an incorrect standard of proof. Instead, Sierra Club generally argues that the burden of proof was on the Companies, and the Commission must not have correctly applied this burden of proof because the Commission did not reach the decision that Sierra Club would like. This is simply not the law. The Commission provided an incredibly detailed Order. While Sierra Club may disagree with portions of that Order, it does not mean the Commission applied the incorrect standard of review.

Sierra Club's mistake can be seen by the plain language of the Order itself, which expressly found that the Companies had the burden of proof: "Although we are mindful of the fact that FirstEnergy has the burden of proof in this proceeding. . . ."[514] As the Commission expressly stated that the Companies had the burden of proof, this assignment of error should be rejected.

O. Rider GDR Is Not Improper Single-Issue Ratemaking.

The Commission appropriately approved Rider GDR. In the Order, the Commission set Rider GDR initially at zero and provided that the Companies may file an application in a separate proceeding to recover costs under Rider GDR.[515] The Commission clarified that these costs "should be limited to Federal and state government mandates enacted after the filing date

[513] Sierra Club AFR, pp. 18-19.

[514] Order, p. 81.

[515] Order, p. 93.

of the application in this proceeding and that no generation or transmission related expenses will be eligible for recovery under Rider GDR."[516]

NOPEC repeats a series of arguments from its Initial Brief regarding the propriety of the Commission's approval of Rider GDR as a placeholder rider. The Commission has already rejected these arguments.[517] The Commission should deny rehearing for this reason alone.

In any event, all of NOPEC's arguments continue to fail. NOPEC argues that the Commission's approval of Rider GDR is unlawful because it is not authorized under R.C. 4928.143(B)(2).[518] NOPEC is incorrect. Rider GDR is authorized under the distribution provisions in R.C. 4928.143(B)(2)(h).

NOPEC argues that since the costs under Rider GDR will be set at zero and identified in the future, the Commission cannot review whether Rider GDR meets the statutory ESP v. MRO test.[519] In short, NOPEC disagrees with the Commission's approval of a placeholder rider set at zero as part of an ESP proceeding. NOPEC's arguments against placeholder riders, however, fall flat. The Commission's approval of Rider GDR as a placeholder rider set at zero is supported by both Commission precedent and the record evidence. The Commission has previously approved other placeholder riders set at zero as part of ESP proceedings.[520] And, contrary to NOPEC's argument, the ESP v. MRO test does not require the Commission to

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[516] Order, p. 93.

[517] Order, pp. 93, 110.

[518] NOPEC AFR, pp. 23-24; NOPEC Initial Brief, pp. 57-58.

[519] NOPEC AFR, p. 31; NOPEC Initial Brief, pp. 57-58.

[520] *AEP ESP3* Order, p. 94 (citing *AEP ESP2*, Opinion and Order (Aug. 8, 2012), pp. 24-25; *In re Duke Energy Ohio, Inc.*, Case No. 08-920-EL-SSO, et al., Opinion and Order (Dec, 17, 2008), p. 17; *In re Ohio Edison Co., The Cleveland Elec. Illuminating Co., and The Toledo Edison Co.*, Case No. 08-935-EL-SSO, et al., Second Opinion and Order (Mar. 25, 2009), p. 15).

quantify the impact of the rider.[521] R.C. 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. 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.

The Commission's consideration of Rider GDR at zero is reasonable and supported by the record. As Company witness Mikkelsen testified, there are no estimates for Rider GDR at this time, so there is no estimate to include in the test.[522] 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, such costs would reasonably be expected to be incurred and recovered whether under an ESP or an MRO.

Lastly, NOPEC repeats arguments that approval of Rider GDR is flawed because recovery of the costs is asymmetric.[523] OMAEG also repeats arguments regarding the Commission's ability to analyze whether the costs are prudent.[524] But these arguments are premature. As the Commission correctly pointed out in the Order, interested parties will have the opportunity to participate in a future proceeding in which the Commission will review costs

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[521] *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").

[522] Mikkelsen Direct, pp. 24-25.

[523] NOPEC AFR, p. 32.

[524] OMAEG AFR, p. 38.

to be recovered under Rider GDR.[525] Accordingly, the Commission should deny rehearing on these issues.

P. The Commission Did Not Unreasonably Fail To Address Intervenor Arguments That Allowing Rider ELR Customers To Opt Out Of The Companies' EE/PDR Portfolio Plans While Continuing To Receive Rider ELR Credits Violates R.C. 4928.6613.

ELPC argues again that Stipulated ESP IV violates R.C. 4928.6613 by permitting Rider ELR customers to opt out of the Companies' EE/PDR portfolio plans and continue to receive Rider ELR credits.[526] Without citing to any authority, ELPC argues that the Commission unreasonably did not address this issue because it did not determine whether this provision of the Stipulation is consistent with R.C. 4928.6613.[527] However, the Commission did expressly address this and found:

> FirstEnergy, IEU-Ohio and Nucor, in their reply briefs, respond to the Environmental Groups' argument that the Stipulated ESP IV violates R.C. 4928.6613, responding that 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, but rather from the Stipulated ESP IV itself.[528]

The Commission need not do anything more on rehearing.

However, if the Commission wishes to provide further clarification, ELPC is incorrect in suggesting that language in Section V.A.1.i.6. of the December 22, 2014 Stipulation is inconsistent with R.C. 4928.6613, which was enacted as part of S.B. 310 in 2014.[529] Rider ELR customers may opt-out of the Companies' EE/PDR Portfolio Plans and continue to receive Rider

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[525] Order, p. 110.

[526] *See* ELPC Initial Brief, pp. 58-59.

[527] ELPC AFR, pp. 23-24.

[528] Order, p. 107.

[529] ELPC AFR, p. 23.

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 R.C. 4928.143(B)(2)(i) – and were continued as authorized ESP components in the Companies' ESP II and ESP III.[530] The Rider ELR credits approved in ESP I pre-dated the Companies' first EE/PDR Portfolio Plan by approximately two years and, thus, necessarily arose from ESP I.[531] 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 R.C. 4928.143(B)(2)(i).[532] Because Rider ELR credits do not arise from the Companies' EE/PDR Portfolio Plan, the Stipulation does not authorize opt outs in violation of R.C. 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. For those reasons, and the fact that ELPC's arguments are not new,[533] the Commission should deny rehearing on this issue.

[530] 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, 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).

[531] 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.

[532] Case No. 12-1230-EL-SSO, Opinion and Order, pp. 35-36 (July 18, 2012).

[533] *See* Order, p. 106.

V. STIPULATED ESP IV IS MORE FAVORABLE IN THE AGGREGATE THAN THE EXPECTED RESULTS OF AN MRO.

EPSA claims that the Commission erred by considering the entire eight-year term of ESP IV in concluding that ESP IV is more favorable than the expected results of an MRO.[534] EPSA argues that because the ESP IV has an eight-year term, and R.C. 4928.143(E) contemplates a review of the ESP after four years, that the Commission is then required by law to only consider part of the ESP IV when reaching a determination under the MRO v. ESP test in R.C. 4928.143(C)(1). EPSA's argument is clearly wrong for several reasons.

First, EPSA wholly ignores R.C. 4928.143(C)(1), which is the statute that dictates how the ESP v. MRO test is required to be conducted under law. That provision requires that 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." It cannot be disputed that one of the "terms and conditions" of ESP IV is the term that it will be in effect. Nothing in R.C. 4928.143(C)(1) authorizes, or even suggests, that only the first half of the ESP be considered when the term is longer than three years. In fact, doing so would directly violate the "in the aggregate" provision of R.C. 4928.143(C)(1). No possible interpretation of "in the aggregate" could mean one-half. Such a suggestion by EPSA ignores the clear language of the statute.

Second, there is nothing in R.C. 4928.143(E), the only statute mentioned by EPSA, that could possibly be interpreted as legally requiring the Commission to only consider one-half of an

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[534] EPSA AFR, p. 76.

ESP longer than three years when initially approving the plan. R.C. 4928.143(E) is not ambiguous. It simply requires in pertinent part that:

> "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."

Nothing in Division (E) gives the Commission the discretion to ignore Division (C)(1) and only consider part of an ESP for purposes of the ESP v. MRO test as part of the Commission's initial approval of the plan. This language in the statute simply sets up a test to be conducted during the fourth year, and nothing more. EPSA's argument is wholly without merit and expressly ignores the mandates of R.C. 4928.143(C)(1), and therefore must be rejected.

A. The ESP v. MRO Test Properly Contemplates The Consideration Of Qualitative Factors.

NOPEC attempts to argue, against the plain language of R.C. 4928.143(C)(1) as well as both Commission and Ohio Supreme Court precedent, that qualitative factors may not be considered in the ESP v. MRO test. NOPEC's attempt is without merit and is simply wrong.[535] NOPEC again attempts to rely on "legislative history" of the statute.[536] This too is inappropriate,

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[535] At the outset of this discussion, it must be noted that since the Commission found Stipulated ESP IV to be over $300 million more favorable than an MRO on a quantitative basis, the Commission, while providing a detailed and proper discussion of the qualitative benefits that fully support the Commission's finding regarding the ESP v. MRO test in this proceeding, did not need to rely on qualitative benefits in this particular instance.

[536] NOPEC AFR, pp. 25-26. 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.")

since that section of its Initial Brief was struck by the Commission.[537] The Commission's ruling is correct that NOPEC's extensive reliance on the "legislative history" of R.C. 4928.143(C)(1) is wholly inappropriate.[538] Further, the Ohio Supreme Court has established that legislative history of a statute should not be considered unless the language of the statute is first determined to be ambiguous.[539] Here, NOPEC does not contend that the language in R.C. 4928.143(C)(1) is ambiguous. This failure eliminates the need to refer to any "legislative history" regarding this statute.[540] The Commission, moreover, has not found that the ESP v. MRO test under R.C. 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.[541]

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[537] Order, p. 37. For a more detailed discussion of this topic, see the Companies' Post Hearing Reply Brief, pp. 315-316.

[538] 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*, Opinion and Order, Case No. 06-786-TR-CVF, 2006 WL 3932766, at *1 (Nov. 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.").

[539] *Dunbar v. State*, 136 Ohio St.3d 181, 2013-Ohio-2163, ¶ 16 ("[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.").

[540] Even if the Commission were to consider NOPEC's improper discussion, 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.

[541] *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, p. 48 (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 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).

What's more, the interpretation of R.C. 4928.143(C)(1) suggested by NOPEC conflicts with the plain language of the statute.[542] NOPEC contends that the reference in R.C. 4928.143(C)(1) to "all other terms and conditions" refers only to pricing and cost considerations.[543] But the language of R.C. 4928.143 includes no such restriction. R.C. 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.[544]

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 Ohio Supreme Court has read R.C. 4928.143(C)(1) to say exactly that.

In *In re Application of Columbus S. Power Co.* ("*CSP I*"), the Ohio Supreme Court rejected a party's attempt to impose a limitation on the Commission's analysis under R.C. 4928.143(C)(1).[545] The Court held that comparing an ESP to an expected MRO "does not bind the commission to a strict price comparison."[546] The Court observed, "in evaluating the favorability of a plan, the statute [R.C. 4928.143(C)(1)] instructs the commission to consider 'pricing *and all other terms and conditions*.'"[547] As a result, the Court held that "the commission

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[542] OCC/NOAC also include a general proposition in its application for rehearing that the Commission may not consider qualitative benefits of an ESP in the ESP v. MRO test. For the same reasons set forth herein, OCC/NOAC's argument must be rejected as well.

[543] NOPEC AFR, pp. 27-28.

[544] R.C. 4928.143(C)(1) (emphasis added).

[545] *In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 402, 407, 2011-Ohio-958, 945 N.E.2d 501, ¶ 27.

[546] 128 Ohio St.3d at 407.

[547] 128 Ohio St.3d at 407 (emphasis in original).

must consider more than price in determining whether an electric security plan should be modified."[548]

NOPEC further presents an erroneous reading of another case, *In re Application of Columbus S. Power Co.* ("*CSP II*").[549] In that case, the Court held that an ESP could only include those items listed in R.C. 4928.143(B).[550] 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.[551] 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 R.C. 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 R.C. 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.[552]

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

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[548] 128 Ohio St.3d at 407 (emphasis added).

[549] *In re Application of Columbus S. Power Co.,* 128 Ohio St.3d 512, 2011-Ohio-1788, 945 N.E.2d 655 (2011).

[550] 128 Ohio St.3d at 520.

[551] NOPEC AFR, p. 27.

[552] *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.").

necessarily permits consideration of non-quantitative factors or, as labeled by the Commission, qualitative factors. Indeed, if the General Assembly had intended to limit the Commission's analysis under R.C. 4928.143(C)(1) to only costs, then it would have expressly said so.[553] 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. Accordingly, NOPEC's proposed interpretation of R.C. 4928.143(C)(1) conflicts with the plain meaning of the statute and must be rejected.

NOPEC then goes on to argue that even if qualitative benefits can be considered by the Commission, the specific qualitative benefits discussed in the Order may not be considered because they do not fall within the categories of R.C. 4928.143(B), notwithstanding that the benefits are wholly consistent with and supportive of the policy of the state in R.C. 4928.02.[554] This NOPEC argument falls equally flat. For example, it states that while the qualitative benefits of energy efficiency programs are consistent with R.C. 4928.02(M), they are not based on R.C. 4928.143(B).[555] This is simply wrong. R.C. 4928.143(B)(2)(i) specifically mentions "energy efficiency programs" as permissible in an ESP. The other examples provided by NOPEC are equally as wrong. They refer to the distribution rate freeze and multiple rate options as not being proper qualitative benefits,[556] but again R.C. 4928.143(B)(2)(h) specifically refers to "Provisions regarding the utility's distribution service," and R.C. 4928.143(B)(2)(g) specifically refers to

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[553] *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.").

[554] NOPEC AFR, pp. 35-36.

[555] NOPEC AFR, p. 36.

[556] NOPEC AFR, p. 36.

transmission service. NOPEC's final two examples relate to diverse generation and reducing generation emissions,[557] both of which directly relate to R.C. 4928.143(B)(1). Once again, NOPEC ignores the plain language of R.C. 4928.143, and thereby reaches a wrong conclusion. NOPEC's arguments in this regard must be rejected.

B. Stipulated ESP IV Is Quantitatively Superior To An MRO.

1. Rider RRS is a benefit to customers.

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.[558] 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.

The Commission relied upon the Companies' forecast, together with another proposal from another witness, to reach its determination that Rider RRS will be a $256 million benefit to customers over the life of the ESP IV. OMAEG contends that the Commission should not have relied upon the Companies' forecast because it is stale.[559] However, this was a highly visible and much discussed issue in the proceeding, and the Commission recognized the depth and quality of

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[557] NOPEC AFR, p. 36.

[558] This does not include additional revenue received from the PJM transitional capacity auctions. *See* Figure 5 on p. 112 of the Companies' Post Hearing Reply Brief (Lisowski Table named "Actual PJM Auction Results Compared To Filed Workpaper").

[559] OMAEG AFR, p. 65.

the Companies' forecast in determining it to be "reliable".[560] Such a conclusion is particularly reasonable given the eight-year term of the ESP IV. Further, as the Commission recognized, using the 2015 EIA Annual Energy Outlook Reference case actually increased prices in comparison to the similar report for 2014.[561] Therefore, if the Companies had updated their forecast, it would have resulted in higher prices, making Rider RRS more favorable for customers.[562]

OCC/NOAC and EPSA, in effect, argue that the Commission should have simply averaged the projections from other witnesses, in addition to the Companies' forecast and one projection from OCC/NOPEC witness Wilson,[563] without consideration of the validity of those other projections. OCC/NOAC and EPSA are wrong, and thankfully the Commission took the time to seriously consider the validity of the projections. Simply because OCC/NOAC and EPSA disagree with the merit of contrary testimony as determined by the Commission is not grounds for granting rehearing. OCC/NOAC and EPSA provide no rationale or explanation as to why the Commission erred by not relying upon projections it found unreliable or simply wrong.[564] OCC/NOAC's and EPSA's suggestion should be rejected.

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

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[560] Order, p. 85.

[561] Order, p. 81.

[562] Order, p. 81.

[563] OCC/NOAC AFR, pp. 49-50. EPSA AFR, pp. 82-83.

[564] *See* Order, pp. 82-85, for an extended discussion of other witnesses' projections and why they were not used.

proceeding.[565] OCC/NOAC, P4S and NOPEC nevertheless argue that Rider DCR should be included in the quantitative ESP v. MRO test.[566] 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.[567]

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.[568]

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 [R.C. 4928.143(C)(1)] clearly limits the Commission's analysis to the 'expected results' of R. C. 4928.142, and does not contemplate

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[565] *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.").

[566] OCC/NOAC AFR, pp. 51-52; P4S AFR, p. 7; NOPEC AFR, pp. 32-34.

[567] 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 Post-Hearing Brief, p. 17.

[568] Hearing Tr. Vol. XX, p. 3929 (Fanelli Cross).

consideration of the results of a distribution rate case."[569] But NOPEC fails to show that the Commission's analysis under R.C. 4928.143(C)(1) is so limited.

NOPEC is plainly wrong. R.C. 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.[570] 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 R.C. 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 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. The Commission 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.

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[569] NOPEC AFR, p. 34.

[570] R.C. 4928.143(C)(1).

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 support low income customers, as well as economic development and job retention activity in their service territories.[571] 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. 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.[572] In any event, similar funding commitments have been recognized by the Commission as quantitative benefits in the Companies' prior ESPs.[573] Therefore, these funding commitments are appropriately included as quantitative benefits of Stipulated ESP IV in the ESP v. MRO test.

NOPEC's arguments that Rider RRS, low income support, economic development, and job retention are not properly considered as quantitative benefits of ESP IV ignore the record and the law and must be rejected. As discussed more fully elsewhere, the Commission clearly determined, consistent with R.C. 4928.143(B)(2)(d) that Rider RRS meets at least both the "limitation on shopping" provision and the "bypassability" provision, consistent with their prior orders. Further, economic development and job retention are also specifically includable as part of an ESP under R.C. 4928.143(B)(2)(i), and therefore may be properly included in the

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[571] Companies' Initial Post Hearing Brief, pp. 102, 106-107.

[572] Hearing Tr. Vol. XXXVI, pp. 7735-7736 (Mikkelsen Cross).

[573] *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. 42 (Aug. 25, 2010).

quantitative aspect of the ESP v. MRO test. Finally, low income support is includable as part of an ESP under R.C. 4928.143(B)(2)(d) as providing "certainty regarding retail electric service." Assisting customers to help avoid disconnection of their electric service is clearly within the scope of this statutory provision. Such provisions have been considered quantitative benefits of all four of the Companies' ESP cases, including cases where NOPEC was a signatory. NOPEC's attack on support for the poorer members of our communities is, frankly, both surprising and disturbing.[574] For the foregoing reasons, NOPEC's arguments should be rejected.

4. Rider GDR was properly excluded from the ESP v. MRO test.

NOPEC and P4S object that the Commission did not assign a value to Rider GDR in the ESP v. MRO test when it approved Rider GDR as part of ESP IV.[575] Rider GDR was approved at a zero amount. The Commission properly recognized that Rider GDR was important to address unforeseen costs associated with governmental mandates during the eight year term of the distribution rate freeze as part of ESP IV. Whether any amounts will be included in Rider GDR is unknown at this time. What is known is that if the Companies ever propose any amounts for Rider GDR, such amounts will not be recoverable until after Commission approval. Thus, the Commission did not err in not assigning a value to Rider GDR.

C. Stipulated ESP IV Is Qualitatively Superior To An MRO.

OCC/NOAC's criticism of the Commission's determination that Stipulated ESP IV is qualitatively better than an MRO is misplaced.[576] The Companies have presented reams of evidence over months of hearings addressing the qualitative benefits of the ESP as compared to a

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[574] Equally surprising is OCC/NOAC's attack on the community agencies that administer low income funds for the Companies, suggesting they should be competitively bid to make the administration of the funds more "efficient". OCC AFR, p. 63. OCC also inappropriately relies upon Staff testimony, since Staff is now a Signatory Party.

[575] NOPEC AFR, p. 31; P4S AFR, pp. 6-7. *See* Order, p. 93.

[576] OCC/NOAC AFR, p. 49.

hypothetical MRO. These benefits include a wide array of factors found by the Commission to be qualitative benefits,[577] including:

- Rider RRS provides long-term rate stability.[578]
- Base distribution rate freeze provides stability to customers.[579]
- Supplier web portal and proposed changes to Supplier Tariffs and Electric Service Regulations support retail competition by removing barriers.[580]
- Continuation of Rider ELR provides economic development and job retention benefits to participating customers.[581]
- Continuation of Rider ELR provides benefits to all customers from a system reliability perspective.[582]
- Allowing Rider ELR customers to shop supports the competitive retail market.[583]
- Continuation of Automaker Credits provides economic development and job retention benefits to qualifying customers by encouraging increased production within the state.[584]

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[577] Order, pp. 118-20.

[578] Companies' Initial Post Hearing Brief, pp. 22-24. Strah Direct, pp. 7-11, Figure 1 (as amended by errata)).

[579] Companies' Initial Post Hearing 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).

[580] Companies' Initial Post Hearing Brief, pp. 35-36. Fanelli Direct, p. 9; Hearing Tr. Vol. XX, p. 3940 (Fanelli Cross).

[581] Companies' Initial Post Hearing Brief, p. 108. Mikkelsen Supp., pp. 11-12; Hearing Tr. Vol. II, p. 274 (Mikkelsen Cross).

[582] Companies' Initial Post Hearing Brief, p. 108. Mikkelsen Supp., pp. 11-12; Hearing Tr. Vol. II, p. 244 (Mikkelsen Cross); Tr. Vol. III, pp. 494-95 (Mikkelsen Cross).

[583] Companies' Initial Post Hearing Brief, p. 36. Mikkelsen Supp., pp. 11-12.

[584] Companies' Initial Post Hearing Brief, p. 148. Mikkelsen Supp., pp. 11-12; Hearing Tr. Vol. III, pp. 622-23 (Mikkelsen Cross).

- Slower phase-out of Rider EDR(d) will allow Rate GT customers to more gradually transition to market based pricing.[585]
- 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.[586]
- Rider NMB Pilot provides customer optionality, education, and an opportunity for savings and better aligns costs with costs causation.[587]
- Commercial HLF TOU rate provides eligible customers an opportunity to reduce their costs and learn about time-of-use rates.[588]
- Business case filing for grid modernization.[589]
- Environmental stewardship goal to reduce CO2 by at least 90% below 2005 levels by 2045.[590]
- Battery resource investment evaluation.[591]
- Robust energy efficiency offerings beginning in 2017, plus programs to support energy efficiency use by small businesses.[592]

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[585] Companies' Initial Post Hearing 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).

[586] Companies' Initial Post Hearing Brief, pp. 34, 104. Mikkelsen Supp., pp. 11-12.

[587] Companies' Initial Post Hearing Brief, pp. 34-35, 104. Mikkelsen Third Supp., p. 2.; Hearing Tr. Vol. II, p. 470; Hearing Tr. Vol. III, p. 642 (Mikkelsen Cross).

[588] Companies' Initial Post Hearing Brief, pp. 35, 104. Mikkelsen Fourth Supp., p. 2; Hearing Tr. Vol. III, p. 463 (Mikkelsen Cross).

[589] Companies' Initial Post Hearing Brief, p. 31. Mikkelsen Fifth Supp., p. 13; Third Supp. Stip., Section V.D.

[590] Companies' Initial Post Hearing Brief, p. 31. Mikkelsen Fifth Supp., p 13; Third Supp. Stip., Section V.E.1.

[591] Companies' Initial Post Hearing Brief, p. 31. Mikkelsen Fifth Supp., p. 13; Third Supp. Stip., Section V.E.2.

[592] Companies' Initial Post Hearing Brief, p. 31. Mikkelsen Fifth Supp., p 13; Third Supp. Stip. Section V.E.3 and V.G.4.b.

- Increased in-state renewable resources.[593]
- Commitment to file a case to transition to decoupled residential base distribution rates.[594]
- Amend the partial service tariffs and modify the Electric Service Regulations.[595]

In contrast, OCC/NOAC would have the Commission simply ignore all of these benefits.[596] OCC/NOAC's argument should be rejected.

VI. THE BENCH'S RULINGS WERE APPROPRIATE.

The Commission appropriately granted the Companies' motion to strike portions of NOPEC's Initial Brief that discussed the legislative history of 2007 Am.Sub.S.B. 221 ("S.B. 221") and attachments A-D, which contained copies of over 100 pages of legislative drafts of S.B. 221 and bill analyses.[597] The Commission found that NOPEC failed to introduce the information before the record closed.[598] The Commission explained:

> The Commission appreciates the efforts of the parties in this proceeding to provide a full record for our consideration, but new information should not be introduced after the closure of the record. . . . [R]egarding the motions to strike portions of NOPEC's initial and reply briefs, we find these motions should be granted on the basis that the disputed portions reference information outside of the record.[599]

Repeating its arguments from its memorandum *contra* the Companies' motion to strike, NOPEC argues that the Order is unlawful because R.C. 1.49 and *Griffith v. Cleveland*, 128 Ohio

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[593] Companies' Initial Post Hearing Brief, p. 32. Mikkelsen Fifth Supp., p. 13; Third Supp. Stip. Section V.E.4.

[594] Companies' Initial Post Hearing Brief, p. 32. Mikkelsen Fifth Supp., p 13; Third Supp. Stip. Section V.F.

[595] Companies' Initial Post Hearing Brief, p. 112. Mikkelsen Fifth Supp., p. 13; Third Supp. Stip. Section V.H.1, 2.

[596] OCC/NOAC AFR, p. 70.

[597] Order, p. 37.

[598] Order, p. 37.

[599] Order, p. 37.

St. 3d 35 (Ohio 2010), permit the Commission to consider the legislative history of S.B. 221.[600] But R.C. 1.49 and *Griffith* are inapplicable here. R.C. 1.49 provides that the court *may* consider legislative history if a statute is *ambiguous*. The Ohio Supreme Court's precedent regarding the rules of statutory interpretation requires that a court first find that a statute is ambiguous before it considers the legislative history of that statute.[601] Consistent with this rule, in *Griffith*, the court first found that the statutory provision at issue was ambiguous and then analyzed legislative history as part of its interpretation of that provision.[602]

NOPEC did not argue at the hearing or in its Initial Brief that R.C. 4928.143(C)(1) is ambiguous. NOPEC only raised the issue after the Companies pointed out the omission in their motion to strike. In any event, NOPEC fails to demonstrate that R.C. 4928.143(C)(1) is ambiguous. NOPEC argues that the ESP factors in R.C. 4928.143(B)(2) are cost-based and then concludes that the Commission's review of an ESP under R.C. 4928.143(C)(1) must be cost-based, *i.e.* consider only quantitative factors.[603] Yet the second proposition does not follow from the first. The plain language of R.C. 4928.143(C)(1) does not limit the Commission to reviewing only quantitative factors. R.C. 4928.143(C)(1) requires a review of "all other terms and conditions." Following this language, the Commission has repeatedly held that the plain language of R.C. 4928.143(C)(1) unambiguously allows for consideration of quantitative and qualitative benefits.[604]

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[600] NOPEC AFR, p. 39; *see also* NOPEC Mem. Contra Motion to Strike, pp. 3-4 (Mar. 14, 2016).

[601] *Dunbar v. State*, 136 Ohio St.3d 181, 186 (2013).

[602] *Griffith*, 128 Ohio St. 3d at 37.

[603] NOPEC AFR, pp. 37-38.

[604] *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*

Accordingly, NOPEC fails to show that the Commission's Order granting the Companies' motion to strike is unlawful. The bottom line is that the NOPEC did not introduce the 100 pages of draft bills and bill analyses into evidence at the hearing. Nor did NOPEC timely argue or show any ambiguity in R.C. 4928.143(C)(1) to open the door for any possible consideration of the legislative history of the statute. The Commission's order striking this material was reasonable.

VII. Conclusion

For the reasons set forth above, the Commission should reject the applications for rehearing filed by intervenors.

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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 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, pp. 73-77 (August 8, 2012).

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CERTIFICATE OF SERVICE

I certify that this Memorandum Contra Intervenor Applications for Rehearing was filed electronically through the Docketing Information System of the Public Utilities Commission of Ohio on this 12th day of May, 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