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 ESTABLISH A STANDARD SERVICE OFFER PURSUANT TO R.C. 4928.143 IN THE FORM OF AN ELECTRIC SECURITY PLAN.	**CASE NO. 23-301-EL-SSO**

OPINION AND ORDER

Entered in the Journal on May 15, 2024

I. SUMMARY

{¶ 1} The Commission finds that the Application for an electric security plan filed by Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company should be modified and approved, subject to the recommendations of Staff, except as otherwise ordered by the Commission.

II. HISTORY OF THE PROCEEDING

{¶ 2} Ohio Edison Company (Ohio Edison), The Cleveland Electric Illuminating Company (CEI), and The Toledo Edison Company (Toledo Edison) (collectively, FirstEnergy or the Companies) are electric distribution utilities (EDUs), as defined in R.C. 4928.01(A)(6), and public utilities, as defined under R.C. 4905.02. As such, the Companies are subject to the jurisdiction of this Commission.

{¶ 3} R.C. 4928.141 mandates that an EDU shall provide a standard service offer (SSO) of all competitive retail electric services necessary to maintain essential electric services to customers, including a firm supply of electric generation service, to all consumers within its certified territory. The SSO may be either a market rate offer in accordance with R.C. 4928.142 or an electric security plan (ESP) in accordance with R.C. 4928.143.

{¶ 4} Most recently, in Case No. 14-1297-EL-SSO, the Commission modified and approved, pursuant to the stipulations filed in that case, FirstEnergy's application for its fourth ESP (ESP IV) to commence on June 1, 2016, and continue through May 31, 2024, pursuant to R.C. 4928.143. *In re Ohio Edison Co.*, *The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case No. 14-1297-EL-SSO (*ESP IV Case*), Opinion and Order (Mar. 31, 2016); Fifth Entry on Rehearing (Oct. 12, 2016); Eighth Entry on Rehearing (Aug. 16, 2017).

{¶ 5} On April 5, 2023, FirstEnergy filed an application (Application) that, if approved, would establish the Companies' fifth ESP for a period to commence on June 1, 2024, and continue through May 31, 2032 (ESP V).

{¶ 6} A technical conference was held on May 10, 2023, to allow interested persons the opportunity to better understand the Companies' Application.

{¶ 7} By Entry issued July 19, 2023, the administrative law judge (ALJ) established an initial procedural schedule, which was extended on October 11, 2023.

{¶ 8} Local public hearings were conducted on September 7, 2023, in Cleveland; on September 14, 2023, in Toledo; and on September 26, 2023, in Akron.

{¶ 9} By Entry issued October 11, 2023, the following parties were granted intervention in this case: Ohio Energy Leadership Council (OELC), Ohio Energy Group (OEG), Northeast Ohio Public Energy Council (NOPEC), Ohio Partners for Affordable Energy (OPAE), Ohio Consumers' Counsel (OCC), Calpine Retail Holdings LLC (Calpine), Interstate Gas Supply (IGS), Citizens Coalition (CC) and Utilities for All (UFA), Northwest Ohio Aggregation Coalition (NOAC), Ohio Manufacturers' Association Energy Group (OMAEG), Walmart Inc. (Walmart), Nucor Steel Marion (Nucor), Utility Workers Union of America Local 126, One Energy Enterprises Inc. (One Energy), Constellation Energy Generation LLC and Constellation NewEnergy Inc. (together, Constellation), Ohio Hospital Association (OHA), Armada Power LLC (Armada), Nationwide Energy Partners, The Kroger Co. (Kroger), Citizens Utility Board of Ohio (CUB), Environmental Law and Policy

Center (ELPC), Retail Energy Supply Association (RESA), Enel North America Inc., Ohio Environmental Council (OEC), Utica East Ohio Midstream LLC, and collectively Direct Energy Business LLC, Direct Energy Services LLC, Reliant Energy Northeast LLC, Stream Ohio Gas and Electric LLC, and XOOM Energy Ohio LLC (together, NRG).[1]

{¶ 10} The hearing commenced on November 7, 2023, and concluded on December 6, 2023. Further, deadlines for initial and reply briefs were set for January 19, 2024, and February 9, 2024, respectively (Tr. Vol. XIV at 2644).

{¶ 11} On December 13, 2023, pursuant to Ohio Adm.Code 4901-1-12, FirstEnergy filed a motion for interim relief. The interim relief would authorize the Companies to conduct two auctions to maintain the Company's auction schedule as proposed in the ESP. On December 19, 2023, NOPEC filed a reply in support of FirstEnergy's motion. On December 20, 2023, NOAC, OMAEG, and OCC jointly filed a memorandum in support of FirstEnergy's motion and Staff filed a memorandum in support of the motion. The motion for interim relief was granted by the Commission on January 10, 2024, and two auctions were conducted as authorized by the Commission.

{¶ 12} Timely initial briefs were filed by the following parties: jointly by CC and UFA, NRG, One Energy, Armada, Walmart, IGS, Constellation, OCC, Nucor, FirstEnergy, OEG, ELPC, OPAE, Staff, CUB, OEC, OELC, RESA, OMAEG, Kroger, NOAC, and Staff. On January 22, 2024, Calpine filed a motion for leave to file a corrected initial brief, which will be addressed later in this Opinion and Order. These same parties also filed timely reply briefs on February 9, 2024.

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1 ChargePoint, Inc. filed a motion to intervene on May 10, 2023, and subsequently filed a notice to withdraw on September 15, 2023. Thus, its motion to intervene was never granted.

III. Discussion

A. Procedural Issues

1. Stay

{¶ 13} On December 6, 2023, together, OCC, OMAEG, and NOAC (moving parties) moved to stay the proceeding as to the Companies' delivery capital recovery rider (Rider DCR) until FirstEnergy's distribution rate case and Case Nos. 17-974-EL-UNC, 17-2474-EL-RDR, 20-1502-EL-UNC, and 20-1629-EL-RDR (collectively, the *FirstEnergy Investigation Cases*) are concluded. These moving parties state that because the former chairman of the Commission (Mr. Randazzo) was indicted on criminal charges, that criminal proceeding could impact the accounting of Rider DCR. The moving parties also assert that they are stymied because the *FirstEnergy Investigation Cases* are stayed, but this ESP V proceeding is moving forward. The moving parties assert that Rider DCR is related to the criminal indictment because cost misallocations have increased the Rider DCR revenue requirements, which appear to be the basis of one portion of the criminal complaint against Mr. Randazzo, citing *In re the 2020 Review of the Delivery Capital Recovery Rider of Ohio Edison Co., The Cleveland Electric Illum. Co., and The Toledo Edison Co.*, Case No. 20-1629-EL-RDR (*2020 DCR Case*), Blue Ridge Expanded Scope Audit (Aug. 3, 2021) at 19; *United States v. Randazzo*, Case No. 1:23-cr-00114, Indictment (Nov. 29, 2023) at 16-19. The moving parties also state that the Federal Energy Regulatory Commission (FERC) audited FirstEnergy, citing *In re: FirstEnergy Corp.*, Docket No. FA 19-1-000 (Feb. 4, 2022), and found several areas of noncompliance, which the parties assert could be related to Rider DCR. The moving parties advocate for the use of the six-part balancing test they say the Commission utilized in the *FirstEnergy Investigation Cases* to determine whether it was appropriate to stay those cases, citing *F.T.C. v. E.M.A. Nationwide, Inc.*, 767 F.3d 611 (6th Cir. 2014). The moving parties assert that, as to the first factor, there is overlap in issues between the criminal case and this proceeding due to similarities of the legal issues and subject matter. Noting that the second factor is the status of the criminal proceeding, the moving parties assert that a new criminal proceeding against Mr. Randazzo "appears to relate specifically to Rider DCR." Looking to the third factor, the moving parties assert that the interests of the courts and the Commission weigh in favor of staying consideration of Rider DCR because misallocation issues and witnesses are shared between this proceeding and the criminal case. As to the public interest factor, the moving parties argue that continued litigation of ESP V could interfere with the criminal investigation, and a limited stay of Rider DCR only would not harm customers. Looking to the private interests factors, the moving parties assert that the interests of FirstEnergy's customers weighs in favor of a stay to ensure fair and reasonable utility charges.

{¶ 14} On December 19, 2023, OEG filed a memorandum contra the motion for a stay. OEG emphasizes the speculative nature of the motion, noting that Rider DCR is not mentioned in the indictment. OEG encourages the Commission to set rates based on evidence rather than speculation. OEG describes DCR riders as allowing utilities to invest in distribution system reliability and notes that all Ohio investor-owned electric utilities have similar riders. OEG explains that the stay could harm customers if the existing Rider DCR continues because Staff proposes a $30 to $36 million Rider DCR rate decrease, which would not be implemented if that element of the case is stayed. If reapproval is completely stayed, OEG says that the Companies would incur an annual revenue reduction of $390 million, which could never be recovered in a future base rate case because base rates are set prospectively. OEG expresses concern that the Companies could terminate ESP V in lieu of ESP IV in that situation, which would be disruptive and call into question other ESP V programs. If the Commission grants the stay, at minimum OEG believes that the Companies would restrict new distribution investments, which it says would negatively affect reliability and customer service. OEG also explains that R.C. 4928.143(B)(2)(h) allows for distribution riders, so the Commission should not grant the request for a stay and should instead adopt Staff's recommendation of changing Rider DCR mechanics to reduce rates $30 to $36 million. OEG also questions the request to stay consideration until the *FirstEnergy Investigation Cases* are concluded, which OEG says amounts to an indefinite stay.

{¶ 15} On December 21, 2023, the Companies filed a memorandum contra the motion for a stay. FirstEnergy alleges that the indictment does not refer to any Commission proceedings or mention any ESP proceeding or rider. FirstEnergy states that it is complete speculation that Rider DCR is related to the indictment, so the six-part test is unnecessary. Additionally, the Companies contend that a stay of Rider DCR consideration would harm the Companies and would put the Companies' ability to continue investing in their distribution system at risk. FirstEnergy adds that Rider DCR is important for customers by offsetting system degradation, maintaining reliability, and promoting gradualism, so it should not be jeopardized due to the parties' unsubstantiated allegations.

{¶ 16} In response, the moving parties argue that ending Rider DCR on May 31, 2024, would not be unsustainable for the Companies, or in the alternative, the Commission could continue Rider DCR as-is until the *FirstEnergy Investigation Cases* conclude. The parties also contend that it is within the Commission's authority to stay consideration of Rider DCR, arguing that it would be consistent with the stay orders in the *FirstEnergy Investigation Cases*. The parties point to the Deferred Prosecution Agreement[2] (DPA) stating that a 2015 consulting agreement amendment was made in exchange for Mr. Randazzo's industrial group withdrawing its opposition to ESP IV. The moving parties assert that demonstrates a connection with Rider DCR because ESP IV included Rider DCR. The parties encourage the Commission to grant this stay to protect customers.

{¶ 17} We have already held that this proceeding is completely unrelated to Am. Sub. H.B. 6. *See FirstEnergy Investigation Cases*, Entry on Rehearing (Oct. 18, 2023) at ¶ 19. Furthermore, we have determined that delaying this proceeding "would be highly

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2 The Deferred Prosecution Agreement is between FirstEnergy Corp. and the U.S. Attorney for the Southern District of Ohio. *United States of America v. FirstEnergy Corp.*, Case: 1:21-cr-86, July 22, 2021, Doc. 3.

improper and may ultimately harm the very customers of FirstEnergy represented by OCC." *Id.* Although the moving parties state that the catalyst for their motion is Mr. Randazzo's criminal indictment, they ask for a stay of consideration of Rider DCR until the completion of FirstEnergy's base rate case and the *FirstEnergy Investigation Cases* - not the criminal case. The parties make various arguments about the connection between that criminal case and this proceeding, but the moving parties do not ask for a stay of this proceeding until the criminal case is concluded. Rather, they request to stay consideration of Rider DCR until the conclusion of other Commission proceedings, which further demonstrates that there is no clear connection between the criminal case and this proceeding. The moving parties suggest that the criminal case "could be" or "appear[s] to be" related to Rider DCR but provide no evidence of the connection beyond speculation. Continuation of the current Rider DCR could delay cost savings for customers, as Staff recommends a significant decrease in Rider DCR, and allowing Rider DCR to expire without a replacement could negatively affect reliability for customers. The tenuous connection between the criminal proceeding and Rider DCR does not outweigh the known harm of staying consideration of Rider DCR. We decline to stay our consideration of Rider DCR based on speculation.

2. AM. SUB. H.B. 6/DEFERRED PROSECUTION AGREEMENT

{¶ 18} Ohio Adm.Code 4901-1-15(F) provides that any party adversely affected by a procedural ruling who (1) elects not to take an interlocutory appeal from the ruling or (2) files an interlocutory appeal that is not certified by the ALJ may still raise the propriety of that ruling as an issue for the Commission's consideration by discussing the matter as a distinct issue in its initial brief prior to the issuance of the Commission's opinion and order.

{¶ 19} OMAEG argues that the ALJ incorrectly excluded evidence relating to Am. Sub. H.B. 6 and FirstEnergy's involvement, pursuant to Ohio Adm.Code 4901-1-15(F). OMAEG seeks to reverse the ALJ rulings that excluded (1) the DPA, (2) FirstEnergy's Form 10-K for the fiscal year ending December 31, 2022, and (3) the FERC Audit Report from

Docket No. FA19-1-000 (Tr. Vol. II at 236; Proffer NOAC Ex. 1; Tr. Vol. I at 108; Tr. Vol. II at 281-287; Proffer OCC Ex. 7). OMAEG asserts that this evidence includes important information about the costs associated with Am. Sub. H.B. 6 that have been or will be embedded in Riders DCR and AMI in the ESP V Application. OMAEG states that the facts of the DPA are not in dispute, so the document should have been admitted or included in the record through administrative notice (Proffer NOAC Ex. 1 at 8-9). As to the Form 10-K and FERC Audit Report, OMAEG states that these documents would have demonstrated a substantial accounting adjustment for FirstEnergy, demonstrating a lack of accuracy in the Companies' accounting practices, which could have called into question whether periodic rider updates will provide sufficient oversight (Tr. Vol. II at 279-280; Proffer OCC Ex. 6). OMAEG contends that FirstEnergy made payments to the Mr. Randazzo's client when Rider DCR was first created, citing *United States of America v. Samuel Randazzo*, Case No. 1:23-cr-114, Indictment (Nov. 29, 2023) at 17. OMAEG says Rider DCR is under investigation and an audit is underway to determine whether FirstEnergy violated its obligation to disclose "side agreements" during the ESP IV case, citing *2020 DCR Case*, Entry (Dec. 15, 2021). In addition to Rider DCR, OMAEG asserts that Rider AMI is also under investigation in the *2020 DCR Case*. OMAEG adds that the FERC Audit Report would demonstrate a significant accounting adjustment and other improper accounting (Tr. Vol. II at 281, 288; OCC Ex. 8; Proffer OCC Ex. 7 at 38). OMAEG asks that the Commission deny Rider DCR until costs have been reviewed and audited and to deny Rider AMI until the Companies' next base rate case or after the *FirstEnergy Investigation Cases* are resolved.

{¶ 20} NOAC asks that the Commission make its decision in this proceeding subject to being reopened if evidence in the *FirstEnergy Investigation Cases* would bear on the decision in this case. NOAC also preserves its rights to appeal the ALJ's decision to exclude the DPA.

{¶ 21} FirstEnergy responds that ESP V is completely unrelated to Am. Sub. H.B. 6, citing *FirstEnergy Investigation Cases*, Entry on Rehearing (Oct. 18, 2023) at ¶ 19.

{¶ 22} At hearing, the ALJ correctly determined that the DPA does not meet the standard for administrative notice because the facts are subject to reasonable dispute and are incomplete, which may cause confusion and prejudice because names have been redacted. Further, the ALJ noted that the DPA is irrelevant to the proceeding, and no charges authorized by Am. Sub. H.B. 6 are included in the Application. (Tr. Vol. II at 235-236.) As to the 10-K, the ALJ denied the request to take administrative notice because it is not the typical type of document the Commission takes administrative notice of, it is irrelevant to the ESP vs. market rate offer (MRO) test, and the party requesting administrative notice elicited no testimony about the impact of the Form 10-K on the Companies' Application in this proceeding (Tr. Vol. II at 276). As to the FERC Audit, the ALJ denied the request to take administrative notice because it is irrelevant to the ESP vs. MRO test. Specifically, as to allegations regarding accounting irregularities, the ALJ noted that accounting irregularities would be more likely discovered in an annual audit than in a base rate investigation several years later. The ALJ also denied the request because the witness was unable to authenticate or discuss the document. The ALJ noted that the parties would have the opportunity to discuss the $108 million accounting reclassification in the 2022 Rider DCR review[3]. (Tr. Vol. II at 286-87.)

{¶ 23} We find that the ALJ properly declined to take administrative notice of these documents at hearing. Turning first to the DPA, the parties have conducted and continue to conduct discovery in the *FirstEnergy Investigation Cases*, and the parties will have the opportunity to address issues relating to the DPA and Am. Sub. H.B. 6 in those proceedings. We have already determined that this Application is "completely unrelated to H.B. 6." *See FirstEnergy Investigation Cases*, Entry on Rehearing (Oct. 18, 2023) at ¶ 19. As correctly noted

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3 *In re Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case No. 22-892-EL-RDR, Audit Report (May 23, 2023) at 17 (where the auditor recommends reclassification of approximately $108 million of assets to Account 186, with the estimated impacts on the Rider DCR revenue requirements to be $(6,808,092) for CEI, $(6,444,769) for Ohio Edison, and $(3,498,947) for Toledo Edison, for a total Rider DCR revenue requirement impact of $(16,751,808).

by the ALJ, no charges authorized by Am. Sub. H.B. 6 are included in this Application. As to the FERC Audit and Form 10-K, the parties will have the opportunity to submit arguments about the approximately $108 million accounting reclassification in the 2022 Rider DCR review. We find each of these documents to be irrelevant to this proceeding. Accordingly, we affirm the ALJ's rulings declining to take administrative notice of the DPA, FERC Audit, and Form 10-K.

3. RESA's Motion to Strike

{¶ 24} In its initial brief, RESA notes that it moved to strike portions of FirstEnergy Witness Miller's testimony at hearing (Tr. Vol. V at 946-948). RESA asks the Commission to reverse the ALJ's ruling and strike the testimony that is based on unsupported energy and capacity price forecasts. In the alternative, RESA asks that we give the price forecasts no weight. RESA argues that the Commission has previously struck testimony of a witness acting as a pass-through of company information without having actual knowledge or expertise, citing *In re the Application of Duke Energy Ohio, Inc. for an Adjustment to Rider MGP Rates*, Case Nos. 14-375-GA-RDR, et al. (*Duke MGP Proceedings*), Opinion and Order (Apr. 20, 2022) at 19-20.

{¶ 25} FirstEnergy responds that the ALJ properly denied RESA's motion to disqualify Mr. Miller as an expert and to strike portions of his testimony (Tr. Vol. III at 654-655; Tr. Vol. IV at 870). FirstEnergy states that Mr. Miller has been involved with energy efficiency program development for 15 years and has education and experience consistent with others who have testified as experts (Tr. Vol. III at 636, 646, 654; Co. Ex. 5 at 1-3). The Companies add that Mr. Miller's analysis is based on publicly available and reliable data from the U.S. Energy Information Administration (Tr. Vol. III at 642, 646-647, 653-654).

{¶ 26} As correctly noted by the ALJ at hearing, the witness' "education and experience based upon his testimony is certainly consistent with the education and experience of many people who claim to be experts before the Commission," and he "has testified as to these matters at the Commission before" (Tr. Vol. III at 648, 654-655). As to RESA's argument that the witness was acting as a pass-through, we do not find that to be true merely because the actual calculations were performed by somebody else in the company not under his supervision. Mr. Miller testified that the information was compiled at his direction, and he is personally familiar with the calculations (Tr. Vol. III at 647). For these reasons, we find that the ALJ's ruling at the hearing was proper and decline to reverse that ruling.

4. MOTION TO FILE INSTANTER

{¶ 27} Initial post-hearing briefs were due on January 19, 2024. Calpine filed its initial post-hearing brief on Friday, January 19, 2024, albeit in the wrong case docket. Calpine filed its brief in Case No. 23-23-EL-SSO instead of this proceeding. Then on Monday, January 22, 2024, Calpine filed in this proceeding a motion for leave to file its corrected initial brief instanter. Calpine stated that the brief delay is not unduly prejudicial, as reply briefs are not due until February 9, 2024. No party filed a memorandum contra to the motion, so we find it appropriate to grant the motion, as we do not find that any party has been prejudiced by the mistake.

B. Summary of the Application and Public Testimony

{¶ 28} In its Application, FirstEnergy requests approval of an ESP that would begin June 1, 2024, and continue through May 31, 2032. As part of the ESP, FirstEnergy proposes to procure generation supply through a competitive bidding process (CBP). The Companies also suggest changes to the CBP that they say will increase supplier participation and reduce risk. As to reliability, FirstEnergy emphasizes its strong track record of delivering reliable service. FirstEnergy says the Application includes provisions that will allow it to maintain reliability and allow it to make a more resilient and reliable delivery system by continuing its capital investment riders, an enhanced vegetation management program and rider, and a plan to recover costs for storm damage repair. Next, the Companies propose a collection of energy efficiency and demand response (EE/PDR) programs that they say will help customers save money on electric bills. The Companies also propose continuing their demand response program as a resource to curtail load during emergency events. As for affordability, FirstEnergy states that its Application includes measures to mitigate bill impacts, such as cost caps, delayed cost recovery, and a phase-down of credits to balance rate impacts. The Companies also suggest the elimination of several inactive riders and tariff provisions. Additionally, FirstEnergy proposes to contribute $52 million of funds not recovered from customers to support low-income customers and electric vehicle programs. (Co. Ex. 1 at 1-4.)

{¶ 29} At the local public hearings held in September 2023, approximately 11 individuals expressed their views regarding FirstEnergy's ESP Application.[4] In addition to this testimony, numerous public comments were filed in these cases. The majority of the public testimony and filed comments raised opposition to FirstEnergy's Application. The primary concern among those testifying in opposition to the Application centered upon what they view as unreasonable rate increases anticipated to occur over the life of the ESP. Witnesses expressed concern that residential customers already struggling to meet financial obligations cannot withstand additional increases in the price of electricity. Numerous witnesses noted that recent inflation exacerbates the financial stress that new rate increases will put on struggling customers. Relatedly, some witnesses felt that consumers that cannot afford electricity will then suffer additional harms, such as medical issues, resulting from an inability to maintain reliable electric services in their residences. Witnesses also pointed to the record revenue and profits reportedly earned by FirstEnergy, especially in light of the allegations of corruption and bribery of public officials, finding it incongruous with requesting additional rate increases at this time. The City of Toledo filed as a public comment a resolution urging the Commission to deny any rate increases for FirstEnergy

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[4] Three of these individuals also presented testimony at the evidentiary hearing, in addition to their testimony at the public hearings (Tr. Vol. XIII at 2255-2271).

customers. Other topics mentioned by witnesses included a request for greater bill payment assistance from the Companies and competitive business disadvantages if rates increase. Other individuals testified on behalf of organizations and asked the Commission to allow the existing Non-Market Based Services Rider (Rider NMB) program to continue without changing the way those charges are billed, so that costs will not increase for those organizations. A few commentors requested that the Commission decline to reduce economic load response (ELR) program credits. Most public comments filed in the case docket largely mirrored those expressed at the local public hearings.

{¶ 30} The Commission will address the arguments in favor and in opposition to the Application. To the extent that an argument has not been explicitly addressed in this Opinion and Order, it has nonetheless been thoroughly considered, and rejected, by the Commission.

C. State Policy

{¶ 31} In reviewing an ESP application, the Commission takes into consideration the policy provisions of R.C. 4928.02 and "use[s] these policies as a guide in [its] implementation of Section 4828.143, Revised Code." *In re the Application of Ohio Edison Co., The Cleveland Electric Illum. Co., and The Toledo Edison Co. for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143,* Case No. 08-935-EL-SSO (*ESP I Case*), Opinion and Order (Dec. 19, 2008) at 12.

{¶ 32} FirstEnergy represents that ESP V advances several state policies. Specifically, FirstEnergy contends that the CBP ensures the availability of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service, produces unbundled and comparable retail electric service for customers, and will support the diversity of electricity and suppliers by encouraging supplier participation, in accordance with R.C. 4928.02(A), (B), and (C). The proposed riders promote the policies in R.C. 4928.02(A) and (E), argues the Companies, by enabling investments for the benefit of the distribution system and building in consumer safeguards like revenue caps, reconciliations, and annual audits. FirstEnergy asserts that Rider AMI also advances the state policies in R.C. 4928.02(D) and (O) by encouraging access for demand-side electric service and promoting customer choice with improved customer usage data. As for Riders NMB and ELR, the Companies represent that they will promote the policies in R.C. 4928.02(A) and (N) by providing customers with the ability to better manage Rider NMB costs, incentivizing demand response, and supporting economic development and job growth. FirstEnergy contends that the EE/PDR plan would advance state policies in R.C. 4928.02(A), (J), (L), (M), and (N) and R.C. 4905.70 by helping customers reduce their bills, protect at-risk populations, promote educational programs, reduce consumption, and make businesses more competitive through energy efficiency. Finally, the Companies submit that the stewardship commitments will promote state policies in R.C. 4928.02(L), (A), and (N) by protecting at-risk populations and facilitating conversion to electric vehicles. (Co. Ex. 2 at 13-14; Co. Ex. 5 at 8-9.) OMAEG contends that it is not possible to analyze whether ESP V would support state policies because FirstEnergy did not analyze the impacts of the upcoming base rate case or the second phase of its grid modernization initiative (Grid Mod II). *In re the Application of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case No. 22-704-EL-UNC, (*Grid Mod II Case*), Application (July 15, 2022).

{¶ 33} Numerous parties have submitted arguments that portions of FirstEnergy's proposal either support or undermine state policies. For instance, OMAEG argues that the ELR program is contrary to state policy because participation in the program is limited to only certain customers. OCC also propounds that Rider ELR violates state policy. CUB contends that the EE/PDR programs promote state policies by increasing efficiency and reducing demand, as well as educating small business owners regarding energy efficiency of their businesses. IGS and NRG argue that the EE/PDR program is inconsistent with Ohio energy policies. NRG asserts that implementing time-of-use rates for all SSO customers would support state policy. Constellation avers that the volumetric risk cap is consistent with Ohio's electric policy. OCC adds that auctions by customer class would be consistent with Ohio energy policy. OMAEG notes that the proposed riders do not support state policy because FirstEnergy is required to provide safe and reliable service if the riders are approved or not. Staff asserts that investments associated with the electric vehicle (EV) transition support the efficient use of the distribution system in accordance with state policy as set forth in R.C. 4928.02(A) and provide appropriate incentives pursuant to R.C. 4928.02(J) and (N), citing Staff Ex. 4 at 5; *In re the Commission's Investigation into Electric Vehicle Charging Service in the State*, Case No. 20-434-EL-COI, Finding & Order (July 1, 2020) at 2.

{¶ 34} The Commission finds that the ESP, as modified by the recommendations that have been adopted by the Commission, is consistent with the policies of the State of Ohio as codified in R.C. 4928.02. The ESP contains several provisions intended to promote reliability in accordance with R.C. 4928.02(A). Also consistent with R.C. 4928.02(A), the proposed ESP reforms and continues the CBP to obtain generation for SSO customers. The ESP, as modified, includes bill assistance and conservation programs targeted to low-income customers pursuant to R.C. 4928.02(L).

D. ESP Term

{¶ 35} *Eight Years.* The Companies propose an eight-year term for this ESP (Co. Ex. 2 at 2). FirstEnergy notes that R.C. 4928.143 contemplates terms longer than three years, and the Commission has previously approved ESP terms longer than six years, citing *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 20; *In re Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer*, Case Nos. 17-1263-EL-SSO, et al. (*Duke ESP IV Case*), Opinion and Order (Dec. 19, 2018) at 33. FirstEnergy also argues that an eight-year term would be subject to an annual Significantly Excessive Earnings Test (SEET) assessment and quadrennial review every four years, citing R.C. 4928.143(F). Further, FirstEnergy contends that if the Commission finds that the ESP fails certain tests, it can terminate the ESP, citing R.C. 4928.143(E). Pointing to the benefits of a longer ESP term, FirstEnergy explains that an eight-year term would provide enhanced rate certainty and stability. FirstEnergy also notes that its $52 million stewardship commitment is based on an eight-year ESP term, so reducing the term would also reduce the total dollar value of the commitment.

{¶ 36} *Six Years.* Staff states that the Commission generally approves ESPs for terms between three and six years. Staff explains that a shorter ESP is more responsive to changing market conditions, while a longer term provides stability for the utility and its customers. Balancing the benefits of both, Staff recommends a six-year term. (Staff Ex. 10 at 3-4.) OELC also advocates for a six-year term, noting that it would accord with Commission precedent of three- to six-year terms (Staff Ex. 10 at 3-4; Tr. Vol I at 173-174). These parties note that reducing the ESP term from eight to six years would decrease Rider DCR costs over the ESP term (Staff Ex. 8 at 5). OELC adds that a six-year term would better align the ESP with current market conditions (Staff Ex. 10 at 4; Tr. Vol. I at 173). OELC supports a six-year term, and Kroger asks that the Commission shorten the requested eight-year term by at least two years.

{¶ 37} *Four Years.* OEG proposes a four-year term for the ESP, noting that the Commission would need utility consent to amend an approved ESP (OEG Ex. 3 at 20). Thus, OEG contends that eight years is too long. OEG also notes that it does not object to Staff's proposed six-year term. OMAEG proposes a three- or four-year term to better align with Commission practice and account for changes in market conditions (Staff Ex. 10 at 3-4; Tr. Vol. I at 173-174; Tr. Vol. XIV at 2561). OCC argues that the ESP V term should be no longer than four years, and FirstEnergy should be required to file a base rate case at the end of that term.[5] OCC and OMAEG note that the Commission has recently approved a four-year ESP term for Ohio Power Company d/b/a AEP Ohio (AEP Ohio) and a three-year ESP for Dayton Power and Light Company d/b/a AES Ohio (AES Ohio), citing *In re the Application of Ohio Power Company for Authority to Establish a Standard Service Offer*, Case No. 23-23-EL-SSO, et al. (*AEP Ohio ESP V Case*), Stipulation and Recommendation (Sept. 6, 2023); *In re the*

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5 Staff states that it would not oppose a requirement for the Companies to come in for another base rate case before the end of ESP V, in addition to the 2024 base rate case (Tr. XIV at 2560).

Application of Dayton Power and Light Co. d/b/a AES Ohio, Case No. 22-900-EL-SSO, et al., (*AES Ohio ESP IV Case*) Opinion and Order (Aug. 9, 2023) at 24. OCC and OMAEG add that the ESP would be subject to a relaxed SEET test during the term of the ESP, citing R.C. 4928.143(F).

{¶ 38} We find that, upon considering the evidence in this case, a five-year term is the appropriate length for ESP V. We agree with Staff's assessment that the Commission typically approves ESPs for lengths between three- and six-years, albeit with some outliers (Staff Ex. 10 at 3-4). One such outlier is FirstEnergy's ESP IV, which was approved for an eight-year term. *ESP IV Case*, Opinion and Order (Mar. 31, 2016), at 20. Routinely approving ESP terms for one utility, FirstEnergy, that are longer than the ESP terms for other utilities would contravene our goal of consistency and equity. We agree with Staff's assessment that shorter ESP lengths better respond to changes in market conditions, while longer terms provide certainty and stability (Staff Ex. 10 at 4). To balance these competing goals and to stay consistent with the ESP terms for other utilities, we find that the appropriate term for ESP V is five years.

E. Stewardship Commitments

{¶ 39} FirstEnergy proposes to commit $52 million of shareholder funds to benefit customers (Co. Ex. 2 at 8). Of the $52 million, $20 million would be used for bill payment assistance programs, $16 million would be used for a new bill discount program for low-income senior citizens, and $16 million would be used for EV initiatives[6] (Co. Ex. 2 at 8-9;

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[6] Initially, the Companies committed that at least $12 million would be used for EV initiatives, and up to $4 million would be used for grid innovation investments. FirstEnergy then explained that it would not pursue the grid modernization project and would spend the full $16 million on the EV program. (Co. Ex. 2 at 8-9; Tr. I at 63-64.) Staff explains that the $4 million grid investment proposal was related to the U.S. Department of Energy Grid Innovation Program (GIP), but the Companies were not selected to receiving funding (Co. Ex. 2 at 6, 10). Staff recommends that if the Companies receive approval with future funding opportunities, the proposal to include $4 million to this project should be approved (Co. Ex. 2 at 7). Additionally, Staff recommends that expenses associated with the GIP project be excluded from

Tr. Vol. I at 63-64). If approved, these funds would be a binding regulatory commitment (Tr. Vol. I at 61).

{¶ 40} Staff generally supports these commitments by the Companies and makes additional recommendations that Staff believes will maximize the impact of these funds.

1. BILL ASSISTANCE

{¶ 41} FirstEnergy proposes to provide $2.5 million annually to assist customers of all three FirstEnergy companies[7] (Co. Ex. 2 at 8). The Companies state that they will use a competitive process to select the administrator for this program and any unused amount will increase the amount available in the next year (Co. Ex. 2 at 9).

{¶ 42} Staff supports this proposal but recommends changes based on the results of the current program. Staff recommends that FirstEnergy designate some funds to customers at risk of disconnection even if the customer does not qualify as low-income. Additionally, Staff suggests that the Companies expand eligibility for three emergency hardship funds administered by the Salvation Army. Staff advocates that the income limit should be 300 percent of the federal income guidelines rather than the 175 percent proposed by FirstEnergy. Another suggestion made by Staff is that the Companies should engage with customers at resource fairs and community events to educate customers on resources for assistance. Finally, Staff recommends that the Companies provide Staff with annual accounting for the program, which Staff says is helpful for evaluation and monitoring of the program. (Staff Ex. 7 at 10-13.)

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distribution rates. NRG opposes the grid innovation program, reasoning that storage is a generation asset that should not be owned by a distribution utility.

7 Previously, $1 million annually was available to all customers and $1.39 million annually was reserved for customers in the CEI territory.

{¶ 43} OPAE, OCC, UFA, and CC generally support FirstEnergy's proposal. OPAE states that approving the proposal to provide bill payment assistance to low-income families would be consistent with other SSO cases. OPAE adds that this program is consistent with state policy, citing R.C. 4928.02(L), by protecting at risk populations. OPAE encourages the Commission to consider increasing the amount available under this program. OCC suggests that FirstEnergy coordinate the new programs with the existing programs to optimize outcomes and to provide further details about the new programs (OCC Ex. 3 at 3). OCC also suggests that FirstEnergy report service disconnections at the zip-code level to help target the funds appropriately (OCC Ex. 3 at 9). UFA and CC disagree with using a competitive process to select the administrator for this program, noting that the current administrators have been successful and should continue their role. UFA and CC also ask that the customer advisory program continue in ESP V.

{¶ 44} FirstEnergy responds that they are open to feedback from Staff and other parties but ask (1) to retain the ability to make the final decision on program design and (2) that feedback does not impede the ability to meet the Companies' commitments. As to Staff's recommendation that unused funds for energy conservation and economic development are credited to ratepayers, FirstEnergy agrees to that recommendation, citing Staff Ex. 4 at 9.

2. SENIOR PROGRAM

{¶ 45} Through this program, FirstEnergy proposes committing $2 million per year to provide a discount on monthly bills for qualifying customers. The Companies explain that qualifying customers are at least 65 years old, have made a payment within 30 days, and are not in the Percentage of Income Payment Plan (PIPP) program.[8] FirstEnergy states

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8 FirstEnergy calls this program the "low-income senior citizen discount," but does not list income requirements as a factor to receive the discount (Co. Ex. 2 at 9).

that it will target spending $2 million per year for this program, and current estimates would set the discount at approximately $5 per month (Co. Ex. 2 at 9). The Companies state that any unused amount will increase the amount available in the next year (Co. Ex. 2 at 9).

{¶ 46} Staff notes concerns with this portion of the stewardship commitments, as the discount would not be tied to causation, need, or risk. Instead, Staff recommends that this portion of the stewardship funds be spent on seniors at risk of disconnection as bill assistance instead of as a bill credit for all seniors over the age of 65. Finally, Staff recommends that the Companies provide Staff with annual accounting for the program, which Staff says is helpful for evaluation and monitoring of the program. (Staff Ex. 7 at 12-13.) UFA and CC oppose this program as proposed and instead ask that the program be restructured so as to better support low-income seniors or to reallocate the money for other purposes.

{¶ 47} As with the bill payment assistance, FirstEnergy responds that they are open to feedback from Staff and other parties but ask (1) to retain the ability to make the final decision on program design and (2) that feedback does not impede the ability to meet the Companies' commitments.

3. ELECTRIC VEHICLE

{¶ 48} To facilitate conversion to electric vehicles, the Companies plan to support education efforts and provide financial assistance to customers who switch to EVs (Co. Ex. 2 at 9). FirstEnergy commits that any funds not expended on the EV program would be spent on the low-income programs to ensure the full $52 million is spent during ESP V (Co. Ex. 2 at 10).

{¶ 49} Staff states that these funds would include campaigns around the EV transition and benefits, financial assistance for customers to obtain government funding, educational toolkits, and financial assistance for customers to obtain fleet advisory services (Staff Ex. 4 at 4). Staff explains that the EV investments would be consistent with state policy in R.C. 4928.02(J) and (N) by incentivizing technologies and facilitating effectiveness in the global economy, citing *In re the Commission's Investigation into Electric Vehicle Charging Service in the State*, Case No. 20-434-EL-COI (*EV Case*), Finding and Order (July 1, 2020) at ¶ 31.

{¶ 50} Staff recommends that the Companies modify the program to limit activities to those directly related to providing distribution services and to add a requirement that the Companies file annual status updates in this proceeding to detail associated spending each year (Staff Ex. 4 at 6). RESA, IGS, and NRG agree with this recommendation. RESA and IGS argue that without this condition, the Commission has no jurisdiction over EV charging, citing *EV Case*, Finding and Order (July 1, 2020) at ¶ 27. IGS explains that there is sufficient competition in this space that it is subject to sufficient protection outside the realm of Commission regulation, citing *EV Case*, Finding and Order (July 1, 2020) at ¶¶ 27, 31, 32. As an alternative, RESA proposes that the Commission could refuse to consider the shareholder funds as part of this proceeding.

{¶ 51} NRG also notes that time-of-use rates would encourage off-peak EV charging, which could reduce stress on the grid. Additionally, NRG recommends that FirstEnergy publish capacity maps to provide a tool for locating sites for EV charger deployment. Staff responds that it does not oppose capacity maps but notes that this proposal should be subject to stakeholder discussion before possible future implementation.

{¶ 52} Separate from the stewardship commitments, Walmart asserts that the Companies' rates and tariffs disincentivize investment in public EV chargers because of the way fixed charges are calculated and billed (Walmart Ex. 1 at 13-14). Walmart suggests that FirstEnergy adopt an EV tariff targeted at public facing direct current fast charging (DCFC) chargers (Walmart Ex. 1 at 15). Walmart notes that Staff stated a preference to address EV rate design in a distribution rate case, but Walmart suggests the Commission approve an interim or pilot program now to provide the necessary information to consider in the next base rate case (Tr. Vol. XIII at 2333). Walmart argues that this stewardship commitment is not a substitute for EV rate design, adding that state policy supports and promotes rate standards to promote affordable EV charging, citing *In re the Commission's Investigation into the Implementation of the Federal Infrastructure Investment and Jobs Act's Electric Vehicle Charging PURPA Standard*, Finding and Order (Nov. 1, 2023) at ¶ 13. Thus, Walmart argues that its proposal is consistent with Ohio policy. In the alternative, Walmart asks the Commission to order the Companies to propose an EV rate design in their next base rate case. Staff responds that the Companies should meet with stakeholders to discuss this and other options to maximize program benefits.

4. COMMISSION CONCLUSION

{¶ 53} The Commission observes that the stewardship commitments proposed by FirstEnergy provide shareholder funding to benefit those in the FirstEnergy territories and are not funded by ratepayers (Co. Ex. 2 at 8). The $2.5 million per year for bill payment assistance will help low-income customers who may be struggling. However, Staff made several recommendations based on the results of the current program. As recommended by Staff, we find that some funds should be delegated to customers at risk of disconnection even if the customer does not qualify as low-income. We also agree with Staff that customers under 300 percent of the federal income guidelines should be eligible for bill assistance. Further, we find valuable Staff's suggestion that the Companies engage with customers at resource fairs and community events to educate customers on resources for assistance. Finally, the Companies should provide Staff with annual accounting for the program for monitoring purposes. (Staff Ex 7 at 10-12.)

{¶ 54} As proposed by FirstEnergy, the $2 million per year senior program would provide a modest discount to qualifying seniors based primarily on age rather than income or need. We observe that the Companies would require the following for discount eligibility: customers who are at least 65 years old, have made a payment in the last 30 days, and are not participating in the PIPP program (Co. Ex. 2 at 9). FirstEnergy did not include income or risk-of-disconnection requirements in their list of qualifications for this discount. We find that, although this program as proposed would provide some benefits to senior customers, the benefits would be even greater by implementing Staff's recommendations. Specifically, focusing these funds on seniors at risk of disconnection, as bill assistance will help maximize the impact of that money (Staff Ex. 7 at 13). Additionally, FirstEnergy should provide Staff with annual accounting for the program to allow Staff to evaluate and monitor the program.

{¶ 55} As to the $16 million shareholder funds proposed to be directed to EV efforts, we find that the EV investments would be consistent with state policy by incentivizing technologies that can adapt successfully to environmental mandates and facilitate effectiveness in the global economy. *See EV Case*, Finding and Order (July 1, 2020) at ¶ 31. Additionally, the Companies should limit activities to those directly related to providing distribution services, in accordance with Staff's recommendation (Staff Ex. 4 at 6). This condition will ameliorate the jurisdictional issues expressed by RESA and IGS. *See EV Case*, Finding and Order (July 1, 2020) at ¶ 27. As to NRG's recommendation that FirstEnergy publish capacity maps, we agree with Staff that this proposal should be subject to stakeholder discussion before possible future implementation. We observe that Walmart's proposal that FirstEnergy adopt an EV tariff targeted at public facing DCFC chargers is addressed in a recently filed stipulation in another proceeding wherein FirstEnergy committed to propose tariff revisions applicable to publicly available EV charging customers in its May 2024 base rate case. *Grid Mod II Case*, Stipulation (Apr. 12, 2024) at 27. Accordingly, we will consider Walmart's proposal as part of our consideration of that stipulation rather than in this proceeding. We also find that the Companies should file annual status updates in this proceeding to detail associated spending each year (Staff Ex. 4 at 6).

{¶ 56} FirstEnergy proposed $52 million in stewardship commitments to be spent over the term of ESP V, which FirstEnergy proposed to be eight years. We find that, because the Commission limited the term of ESP V to five years instead of the proposed eight years, we find it appropriate to prorate the stewardship commitments such that the Companies are committed to spend $32.5 million rather than the full $52 million. However, FirstEnergy is free to commit the full $52 million over the five-year ESP term if it so chooses.

F. Generation Riders

{¶ 57} The Companies are not proposing changes to approved riders related to SSO service costs. These include the Generation Service Rider (Rider GEN), Generation Cost Reconciliation Rider (Rider GCR), Alternative Energy Resource Rider (Rider AER), and Non-Distribution Uncollectible Rider (Rider NDU) (collectively, Generation Riders). Rider GEN annually recovers the Companies' purchase power expenses, which are reconciled in Rider GCR along with actual expenses. Rider NDU recovers non-distribution uncollectible expenses, while Rider AER covers compliance costs for alternative energy resources. Riders GCR, AER, and NDU undergo quarterly reconciliation and annual audits to ensure accurate expense recovery. FirstEnergy states that volumetric risk cap (VRC) procurement costs would be reconciled through Rider GCR, along with true-ups between capacity proxy price (CPP) and actual capacity prices. The Companies request continued authorization of these Generation Riders under existing terms and conditions.

{¶ 58} We find this proposal, with the exception of the VRC component, as explained further below, to be a reasonable and an appropriate continuation from the prior ESP.

G. Competitive Bidding Process

{¶ 59} FirstEnergy argues that its proposed CBP will allow for fair and competitive energy procurement. The Companies note that they propose to continue utilizing a descending clock auction format (Co. Ex. 6 at 28-30, 33), as well as continuing other CBP elements, such as a staggered and laddered schedule of procurements, a mix of products, and a slice of the system approach with each tranche as one percent of the total SSO load obligation (Tr. Vol. IV at 755, 783-784; Co. Ex. 6 at 20-21, 36). FirstEnergy asserts that its CBP procedures ensure a fair and competitive auction, including protecting confidential information, encouraging bidder participation, and holding bidder information sessions (Co. Ex. 6 at 18-20).

{¶ 60} Staff, RESA, and IGS support FirstEnergy's proposal to utilize this auction structure. Staff states that the auction structure is effective and has been utilized by each of the Ohio EDUs for many years (Staff Ex. 6 at 2). RESA notes that no party presented testimony opposing the continuation of the auction framework.

{¶ 61} Constellation asserts that the current CBP has weaknesses, which results in unnecessary risk premiums being built into pricing. Constellation asserts that with the recent large-scale customer migration from a government aggregator back to the SSO in the 2022-2023 season, those risks have increased dramatically, which are now priced into SSO rates (OCC Ex. 2 at 4; Constellation Ex. 11 at 12, 18; Tr. Vol. IV at 760-761). Specifically, Constellation points out that during the time of mass migration back to the SSO, the commercial SSO load increased more than 291 percent over the average, and the industrial SSO load increased more than 1,667 percent over the average (Constellation Ex. 11 at 14; OELC Ex. 10). Constellation asserts that the evidence of CBP risks is demonstrated by the fewer auction participants in recent auctions (FirstEnergy Ex. 6 at 9; Constellation Ex. 11 at 17). As compared to Ohio's auctions, Constellation contends that other state auctions have drawn more bidder interest due to more favorable procurement structures (Constellation Ex. 11 at 18). Constellation asserts that the risk premiums associated with the CBP will persist in ESP V if changes are not made (Tr. Vol. IV at 769; Tr. Vol. XI at 1951-52; Tr. Vol. XIII at 2358).

1. VOLUMETRIC RISK CAP

{¶ 62} FirstEnergy proposes a VRC on load migration back to SSO service, which sets initial benchmark levels based on daily Peak Load Contribution (PLC) per tranche. Suppliers' volumetric exposure would be capped at 20 MW above the benchmark. (Co. Ex.

6 at 6-7; Tr. Vol. IV at 741-742; Co. Ex. 4 at 3.) FirstEnergy states that the VRC will not affect customers' ability to shop and is expected to rarely be triggered, in the event of significant customer migration back to the SSO (Co. Ex. 6 at 9). FirstEnergy notes that VRC mechanisms have been successfully used in other jurisdictions (Co. Ex. 6 at 7-9).

{¶ 63} Rather than utilizing FirstEnergy's proposed 20 MW cap, Constellation proposes a lower 2-5 MW cap, which it states is approximately 15-40 percent of PLC tranche size. Constellation asserts that a 20 MW cap would mitigate only the most extreme risk. (Constellation Ex. 11 at 21, 23, 33.) In proposing the cap to use, Constellation reasons that it should be set at a level that allows some customer movement but also provides incentive against customers gaming the SSO rate against market prices (Constellation Ex. 11 at 20). Constellation argues that a VRC would respond to the Commission's policy interests.[9]

{¶ 64} FirstEnergy explains that the VRC would reduce SSO suppliers' load risk, which it believes would lower bid premiums and encourage competitive pricing for SSO customers (Co. Ex. 6 at 7). Constellation agrees and says load quantity is a major risk factor for suppliers, which would be mitigated with the VRC (FirstEnergy Ex. 6 at 8; Constellation Ex. 11 at 20; Tr. Vol. XII at 2104-05). As evidence that the VRC would lead to lower prices, Constellation explains that a VRC has been used successfully in other jurisdictions (Tr. Vol. IV at 763; Constellation Ex. 11 at 19; FirstEnergy Ex. 6 at 9). Constellation adds that Staff recommends reducing risk premiums in other contexts (Tr. Vol. XIV at 2470, 2493-2494), so for consistency the Commission should reduce the risk premiums in the SSO auctions by implementing the VRC. Constellation contends that the VRC would result in greater supplier participation and greater competition in the SSO auctions (Co. Ex. 6 at 6).

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9 See In re the Procurement of SSO Generation as Part of the Fourth Electric Security Plan for Customers of Ohio Edison Co., The Cleveland Electric Illum. Co., and The Toledo Edison Co., Case No. 16-776-EL-UNC et al. (ESP IV Auction Case), Entry (Jan. 3, 2023) at ¶ 3; In re the Proposed Modifications to the Electric Distribution Utilities' Standard Service Offer Procurement Auctions, Case No. 23-781-EL-UNC (Capacity Proxy Case), Entry (July 26, 2023); and AES Ohio ESP IV Case, Opinion and Order (August 9, 2023) at ¶ 247.

{¶ 65} Staff, IGS, OELC, and NRG oppose FirstEnergy's use of the VRC. The parties emphasize that if loads exceed the VRC cap, load would be supplied at real-time market prices (Co. Ex. 6 at 6-7). While it may lead to slightly lower SSO bid prices by reducing risk premiums, Staff, OELC, IGS, and NRG reason that the proposal would expose SSO customers to the risk of paying extraordinarily high market prices during periods of high demand. Specifically, IGS and OELC note that short-term market prices are volatile and can rise to almost 100 times that of forward market prices (IGS Ex. 1 at 11; Tr. Vol. IV at 728-730). NRG and IGS express concern that a known risk would be borne by customers, while the benefit of lower SSO pricing is speculative (Co. Ex. 6 at 8-9; Staff Ex. 6 at 3-4; Tr. Vol. IV at 776, 780). As to risk allocation, NRG and IGS argue that customers do not have the ability to manage the risk that the VRC would be triggered, whereas suppliers are more sophisticated and do have the ability to hedge prices (IGS Ex. 1 at 7-8, 11-12; Co. Ex. 6 at 8; Staff Ex. 6 at 3-4; Tr. Vol. XII at 2106). NRG reasons that risks have always existed and the volatility in the 2022-2023 season is not new. Rather than serving customers, IGS suggests that the VRC would appeal to SSO bidders who do not want to manage risk (Tr. Vol. XII at 2104). As for Constellation's proposal to lower the VRC threshold to 2-5 MW rather than 20 MW, Staff and OELC note that proposal would make it even more likely for customers to be faced with extraordinarily high prices (Tr. Vol. XI at 1917-18).

{¶ 66} Staff states that the Commission has recently signaled that it was not prepared to shift migration risk from suppliers to consumers, citing the *AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023) at ¶ 247. NRG and IGS assert that there is no evidence in the record that the proposed VRC would be a net benefit to SSO customers over the current process, so the Commission should reject it. Noting that FirstEnergy has not proposed a tariff mechanism to effectuate the VRC, OELC asserts that FirstEnergy has not sufficiently analyzed the impacts of its proposal (Tr. Vol. IV at 711).

{¶ 67} Constellation asserts that relying on data from the 2022-2023 season is improper because, had the VRC been in place, there would have been more supplier participation and lower clearing prices – in other words, the offsetting benefits of the VRC were not realized (Tr. Vol. XI at 1918; Tr. Vol. IV at 733, 757-758). Noting another reason that the data from the 2022-2023 season is misleading, Constellation explains there was no disincentive to switch back to the SSO, as there would be if the VRC were in place (Tr. Vol. XI at 1949; OELC Ex. 13).

{¶ 68} Constellation adds that the VRC would not harm customers because SSO customers will pay less due to reduced risk premiums in auction clearing prices. Constellation asserts that the VRC does not shift risk to customers because the migration risk already exists, and SSO customers already pay for that risk in SSO rates (Tr. Vol. IV at 706-707; Tr. Vol. XI at 1939). Constellation points out that when other parties argue that the VRC will result in unreasonable rates, they assume that the VRC will be triggered and that real-time market prices will be higher than the SSO prices, and those assumptions are without record support (Tr. Vol. IV at 706, 733; Tr. Vol. XI at 1918-1921, 1948-1949). To mitigate the concerns expressed about risk to customers, Constellation explains that if the VRC is exceeded, only the percent that has exceeded the VRC would be served at real-time market prices rather than the whole SSO load being subject to market prices (Tr. Vol. XI at 1946-48).

{¶ 69} IGS contends that the declining clock auction process functions to squeeze any unnecessary risk premiums out of SSO bids, as winning bidders have the lowest cost inputs and highest risk tolerance (IGS Ex. 1 at 7-8). Constellation disagrees, arguing that there is no evidence that risk premiums related to customer migration are "squeezed out" with the current auction process, and risk premiums have been higher recently than in the past (Constellation Ex. 11 at 11-16; Co. Ex. 6 at 8-9; Tr. Vol. IV at 710). Additionally, Constellation alleges that supplier participation in the auctions has dropped due to customer migration risk (Co. Ex. 6 at 9).

{¶ 70} Constellation asserts that the Commission's "minimum stay" provisions, which temporarily prevent government aggregators from re-enrolling customers that have been dropped to default service, are not sufficient to mitigate the risk borne by SSO suppliers, citing *In re App. of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co. for Approval of Tariff Amendments*, Case No. 22-1127-EL-ATA, et al., Finding and Order (Mar. 8, 2023) at ¶ 19. Constellation asserts that the minimum stay provision does not prevent customers from being dropped from aggregation en masse, which is the risk for default SSO suppliers (Constellation Ex. 11 at 13; Tr. Vol. XI at 1944).

{¶ 71} FirstEnergy proposes that it would manage excess load migration through an automated process by PJM Interconnection, LLC (PJM), with costs reconciled through the Companies' existing SSO mechanism (Co. Ex. 6 at 7). Constellation and RESA recommend that the load over the cap be supplied by the default service suppliers rather than directly by FirstEnergy. Constellation explains that there would be no benefit to FirstEnergy supplying the load, and it would be improper to house costs for serving the load in FirstEnergy's account (Constellation Ex. 11 at 24; Tr. Vol. IV at 695-696, 745-746, 770; Tr. Vol. XI at 1918-19). Additionally, Constellation expresses the concern that FirstEnergy is not permitted to provide competitive generation service to the SSO, pursuant to R.C. 4928.17 and 4928.02. Company Witness Lee testified that FirstEnergy would secure power above the VRC due to a need for manual calculations and ancillary services costs, but RESA challenges these reasons (Tr. Vol. IV at 746). Additionally, RESA points out that the calculation would be the same regardless of who supplies the electricity (Constellation Ex. 11 at 24). As for ancillary service costs, RESA contends that those costs are negligible for the load above the proposed VRC (Constellation Ex. 11 at 24; Tr. Vol. IV at 746). Thus, RESA concludes that there is no benefit for FirstEnergy to secure the power above the VRC, but there are potential harms, including the requirement for FirstEnergy to provide daily day-ahead bids and costs associated with the SSO load residing in PJM sub-accounts rather than FirstEnergy's account (Constellation Ex. 11 at 24; Co. Ex. 6 at 7). Staff is open to that option of the default service providers providing the load over the VRC, but Staff recommends that at least initially, FirstEnergy be responsible for procurement of the excess (Staff Ex. 6 at 5).

{¶ 72} Staff notes that the proposal's unusual calculation of PLC values raises issues, as it differs from PJM's fixed PLC system. Staff suggests that if a VRC were adopted, PLC values should be calculated such that only significant customer migration would trigger the cap and not just increased usage. If the Commission implements a VRC, Staff would make further recommendations, including transparency in daily PLC values on the auction website, resetting the cap for two-year products based on actual PLC at the start of the second year, and evaluation of alternative procurement strategies if the cap is exceeded. (Tr. Vol. IV at 771-72; Tr. Vol. XIII at 2375-76; Staff Ex. 6 at 6.) As to Staff's critique about the PLC calculation, Constellation notes that the PLC information is already gathered and published on FirstEnergy's CBP website (FirstEnergy Ex. 6 at 6-7; OELC Ex. 14; Tr. Vol. IV at 724-725).

{¶ 73} The Commission observes that FirstEnergy and Constellation advocate for a VRC, arguing that it would reduce risk premiums in SSO auction bids. Specifically, they mention the risk of large-scale customer migration that occurred in the 2022-2023 season introduced extra volatility for bidders such that those bidders either now do not participate in the auction or add in higher risk premiums to their SSO auction bids (Tr. Vol. IV at 706-707, 710; Tr. Vol. XI at 1939; Constellation Ex. 11 at 11-16; Co. Ex. 6 at 8-9). To assess the veracity of these claims, we first look to the clearing prices in recent years. The clearing prices for 12-month products were $68.11 in March 2022; $122.30 in October 2022; $97.70 in January 2023; $83.75 in March 2023; and $69.27 in February 2024. In March 2024, the clearing price for a 24-month product was $78.51. *See ESP IV Auction Case*, Finding and Order (Mar. 7, 2022) at ¶ 7; *ESP IV Auction Case*, Finding and Order (Oct. 5, 2022) at ¶ 7; *ESP IV Auction Case*, Finding and Order (Jan. 11, 2023) at ¶ 7; *ESP IV Auction Case*, Finding and Order (Mar. 22, 2023) at ¶ 7; *In re the Procurement of SSO Generation as Part of the Fifth Electric Security Plan for Customers of Ohio Edison Co., The Cleveland Electric Illum. Co., and The Toledo Edison Co.*, Case No. 24-133-EL-UNC (*ESP V Auction Case*), Finding and Order (Feb. 21, 2024) at ¶ 8; *ESP V Auction Case*, Finding and Order (Mar. 20, 2024) at ¶ 8. We observe that the auction clearing prices increased dramatically in late 2022 and early 2023. However, the February 2024 clearing price, $69.27, was similar to the clearing price in March 2022, $68.11, before the mass customer migration back to the SSO described by the parties. Although prices rose dramatically in late 2022 and early 2023, we are pleased that the clearing prices have been significantly lower in recent auctions.

{¶ 74} By looking closely at these recent SSO procurements, we see evidence that the risk premiums that FirstEnergy and Constellation express concerns about have not and will not remain high to the detriment of customers. As to Constellation's argument that supplier participation in the auctions has dropped due to customer migration risk, we note that the clearing price – the most important element for customers – has returned to more normal levels in the 2024 auctions. As we recently stated in another proceeding, we will continue to monitor the auctions and clearing prices so that we may implement mitigation measures that are commensurate to the circumstances at hand. *See AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at ¶ 82. One such measure the Commission recently undertook was preventing government aggregators from re-enrolling customers that have been dropped to the default service. *See In re App. of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co. for Approval of Tariff Amendments*, Case No. 22-1127-EL-ATA, et al., Finding and Order (Mar. 8, 2023) at ¶ 19. Another such measure was ordering the utilities to utilize a capacity proxy price to maintain auction schedules. *See Capacity Proxy Case*, Finding and Order (Dec. 13, 2023) at ¶32. In addition to these recent decisions, the Commission remains committed to undertaking other appropriate measures as circumstances demand.

{¶ 75} At this time, we do not find that implementing a VRC would be an appropriate response, given the risk that the VRC could impose on customers. As noted by Staff, IGS, OELC, and NRG, if the electric load ever exceeds the VRC cap, that excess load would be supplied at real-time market prices (Co. Ex. 6 at 6-7). Although FirstEnergy notes that the VRC would be rarely triggered, we note that if or when the VRC is triggered, real-time market prices are volatile and can be significantly higher than the SSO price (IGS Ex. 1 at 11; Tr. Vol. IV at 728-730). To put it simply, at this time we find that the known VRC risk of subjecting customers to volatile real-time market prices outweighs the possible reward of lower risk premiums built into the auction clearing prices.

{¶ 76} Additionally, we find that the SSO suppliers are better able to manage the risks inherent in the electric market than customers. Suppliers are sophisticated participants who can hire experts and analyze data and trends to predict future risk. Further, suppliers have tools that customers do not have, such as the ability to hedge prices. (IGS Ex. 1 at 7-8, 11-12; Co. Ex. 6 at 8; Staff Ex. 6 at 3-4; Tr. Vol. XII at 2106.) We also point out that customers may not know when the VRC has been triggered and that they are subject to real-time market pricing such that they may reduce their usage accordingly.

{¶ 77} For the reasons outlined above, even though VRCs have been implemented in some other jurisdictions, we do not find that a VRC would be appropriate in Ohio at this time. Furthermore, in the event that we find it appropriate to consider implementing a VRC in the future, the Commission would likely consider that mechanism for all EDUs in a single proceeding to promote consistency and fairness. Our conclusion to decline the VRC proposal is consistent with our recent decisions declining to shift risk from suppliers to customers. *See AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023) at ¶ 247; *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at ¶82.

2. CAPACITY PROXY PRICE

{¶ 78} The Companies propose a CPP mechanism to be used if there is no base residual auction (BRA) price available at the time of an SSO auction (Co. Ex. 6 at 11-13). FirstEnergy explains that the CPP would act as a proxy price, averaging the two most recent PJM capacity year values and would include a true-up mechanism. The Companies argue that the CPP would maintain auction schedules despite BRA uncertainty, which would benefit customers. The Companies contend that similar mechanisms in other PJM states have received positive feedback and align with the recent Commission decision in *Capacity Proxy Case*, Finding and Order (Dec. 13, 2023) at ¶32. FirstEnergy states that its proposal, which was developed with the SSO auction manager, provides certainty and fulfills the Commission's directive to establish a CPP mechanism, citing *Id.* at ¶35. (Co. Ex. 6 at 10-13; Co. Ex. 4 at 3.)

{¶ 79} Constellation, Staff, and OCC[10] support the CPP. These parties assert that establishing a CPP in ESP V would be consistent with the Commission's decision in the *Capacity Proxy Case*, Finding and Order (Dec. 13, 2023). Constellation asks that the Commission clarify that the CPP is a part of ESP V rather than merely relying on the *Capacity Proxy Case*, which could cause confusion. Constellation notes that the CPP will help mitigate some risk.

{¶ 80} IGS does not support the CPP and argues that it would expose customers to the risk of resettlement with new capacity prices after PJM has capacity auctions again. Noting that in the *Capacity Proxy Case* the Commission has already directed EDUs to implement a CPP if the actual price is not yet established, IGS asks that the Commission restrict the CPP mechanism to the short-term only until FERC finalizes its capacity market reform proceedings. IGS reasons that the CPP will become unnecessary when PJM's base residual auctions return to a normal schedule. (IGS Ex. 1 at 9; *Capacity Proxy Case*, Finding and Order (Dec. 13, 2023) at ¶35.) Responding to IGS' argument, Staff points out that the CPP will not be utilized if it is not needed at a later time, so there is no need for the Commission to limit its duration.

{¶ 81} In our recent decision in the *Capacity Proxy Case*, the Commission directed EDUs to utilize a CPP for years in which no actual capacity price has been established, including at least an annual true-up of the CPP. *Capacity Proxy Case,* Finding and Order (Dec. 13, 2023). We find that FirstEnergy's CPP proposal is consistent with that decision and should be implemented in ESP V. As to IGS' argument that it exposes customers to the risk of resettlement, we observe that risk is overshadowed by the more significant risk of delayed

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[10] We infer OCC's support, as OCC incorrectly asked the Commission to order FirstEnergy to establish a CPP mechanism (OCC Initial Br. at 11-12; OCC Ex. 2 at 4), whereas FirstEnergy had already proposed a CPP.

auction schedules. We decline to add an expiration date to the CPP, as the Commission can consider removing the CPP in the future if it is no longer needed.

3. SEPARATE AUCTIONS BY CLASS

{¶ 82} FirstEnergy did not propose separating SSO auctions by customer class in its Application or briefs, but intervenors Constellation and OCC did make such a proposal. The current auction process utilizes a slice of system approach, with one tranche supplying one percent of the aggregate load for all customer classes (Tr. Vol. IV at 755; Co. Ex. 6 at 20-21). Constellation argues that the slice of system construct creates risks for suppliers (Constellation Ex. 11 at 15). Specifically, Constellation contends that different customer classes have different load shapes, which is challenging for suppliers, and creates a risk premium shared by all customer classes. Constellation asserts that suppliers have tools to mitigate certain risks, but the overall SSO load volume is less predictable. (Constellation Ex. 11 at 15-16; IGS Ex. 1 at 7; Tr. Vol. IV at 764, 759.) Because the class-based auctions would allow suppliers to decrease their risk, Constellation argues that would translate to lower auction clearing prices (OCC Ex. 2 at 5). Constellation states that separate auctions by class would support the Commission's policy of promoting cost-causation principles. As to implementation, Constellation notes that FirstEnergy's auction manager has experience with class-based auction products (Constellation Ex. 1; Constellation Ex. 2; Constellation Ex. 11 at Attach. B; Tr. Vol. IV at 753, 768-69).

{¶ 83} From a customer perspective, Constellation asserts that class-based auctions would avoid one customer class subsidizing the risks of another class (Constellation Ex. 11 at 29-30). Constellation suggests separate auctions for residential, small commercial, and large commercial customer classes (Constellation Ex. 11 at 26). OCC submits that there should be a separate auction for residential customers, noting that separating the auctions may lead to lower cost outcomes for residential consumers (OCC Ex. 2 at 18). By holding the auction together for all customer classes, OCC argues that the lower-cost consumers effectively subsidize the service for higher-cost consumer classes (OCC Ex. 2 at 11). OCC adds that separating the auctions by class would be consistent with the state policies, citing R.C. 4928.02(A)-(D), (G)-(I), and (L).

{¶ 84} Staff, FirstEnergy, and IGS oppose the proposal to hold separate SSO auctions by customer class. Expressing concerns that separating products by customer class may not result in a lower price, Staff and IGS explain that mixing all the rate classes in a single product mitigates the risks that would be apparent for a single rate class. OELC reasons that the current process incentivizes bidders to limit risk premiums as much as possible, and the proposed class-based auction format does not guarantee cost efficiency or lower prices (Co. Ex. 6 at 33). In fact, IGS adds that OCC Witness Wilson, who supports the auctions by class, and Staff Witness Benedict testified that a residential customer class could result in higher SSO pricing at auction (OCC Ex. 2 at 16; Staff Ex. 6 at 9). FirstEnergy notes that no other Ohio EDU conducts SSO procurements by class. Staff, IGS, and FirstEnergy point out that the Commission recently declined to separate the auctions by class, citing the *AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023), at ¶ 247.

{¶ 85} Constellation argues that other jurisdictions conduct class-based auctions successfully, which Constellation asserts proves the effectiveness of this type of auction (Tr. Vol. IV at 753, 767-768; Constellation Exs. 1, 2, 4). OCC adds that it is common in other states for the residential class to have a separate auction or an auction combined with only small commercial customers (OCC Ex. 2 at 12). Constellation asserts that Ohio is an outlier in its current approach, as no other PJM jurisdiction procures load by combining large commercial and industrial customers with residential customers (Constellation Ex. 11 at 27; OCC Ex. 2 at 12-13). By comparing Ohio and Pennsylvania prices, Constellation argues that class-based auctions in Pennsylvania have produced lower auction clearing prices (Constellation Ex. 11 at 28).

{¶ 86} OELC, IGS, and FirstEnergy argue that separating the auctions by class could also result in some tranches being unserved (Tr. Vol. X at 1885; Co. Ex. 6 at 36). Constellation responds that the concern is mere speculation, and there is a contingency plan in the event that tranches are not secured at auction (FirstEnergy Ex. 6 at 36-38; Tr. Vol. IV at 790-91; Tr. Vol. XIII at 2377-78).

{¶ 87} The Commission appreciates the feedback from all parties regarding the possibility of restructuring auctions from a slice of the system approach to conducting separate auctions by class. However, we are not persuaded that separating the auctions by class would result in aggregate savings for customers (Co. Ex. 6 at 33). In fact, evidence was presented that separating the auctions by class could produce higher SSO pricing (OCC Ex. 2 at 16; Staff Ex. 6 at 9). Specifically, Staff testified that residential customers have more extreme peaks in usage and thus "can be more expensive to serve than a customer with a flatter load profile" (Staff Ex. 6 at 7). Thus, we do not find that separating the auctions by customer class would support state policies, as alleged by OCC. As to Constellation's arguments regarding the risks for suppliers in a slice of the system auction, we observe that bidders have successfully supplied the electric load under this system for many years. We have full faith in the ability of those suppliers to calculate risks as they place their bids at auction and to then utilize tools, such as price hedging, to minimize risk. The Commission recently considered this very issue and declined to adopt a class-based auction structure in another proceeding. *AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023), at ¶ 247. We add that, as with our consideration of the VRC above, if we do decide to explore the possibility of conducting auctions by consumer class in the future, the Commission would likely consider that mechanism for all EDUs in a single proceeding to promote consistency and fairness amongst EDUs.

4. ELIMINATING 36-MONTH PRODUCTS

{¶ 88} The Companies propose reducing the maximum contract term from 36 to 24 months in their CBP, reasoning that this change would align with bidder preferences, encourage competitive bidding, and lower prices for customers. Longer contracts pose higher risk due to future market forecasting, resulting in higher bid premiums. FirstEnergy reasons that reducing the maximum contract term to 24 months helps suppliers mitigate risk and lower premiums, benefiting customers. (Co. Ex. 6 at 10.) Staff does not oppose the proposal to eliminate 36-month products, noting that the change could increase volatility but also result in lower risk premiums in bids (Staff Ex. 6 at 5, 7). Constellation states that it does not oppose or support the elimination of the 36-month product.

{¶ 89} We find the proposal to eliminate 36-month products in the CBP to be a reasonable proposal to lower risk premiums and therefore reduce costs for consumers. The Commission observes that, although the Companies will no longer utilize 36-month products, 24-month products will still serve to mitigate volatility as compared to using only 12-month products (Tr. Vol. IV at 783-784; Co. Ex. 6 at 21).

5. Other Proposals

{¶ 90} The Companies propose five changes to their supplier collateral mechanisms that they say will reduce risk for customers and themselves. First, they introduce an Independent Credit Requirement per Tranche (ICRT), a fixed collateral per tranche declining over time, akin to Duke Energy Ohio, Inc. (Duke Energy Ohio) and AEP Ohio's structures. Second, FirstEnergy proposes modifications to the Mark-to-Market (MTM) collateral requirement to explicitly address margin calls due to load level changes in ESP V. Third, the Companies propose reducing maximum unsecured credit limits, which will still be tied to credit rating and net worth but will not affect the general availability of unsecured credit. Fourth, they propose to utilize the lowest credit rating, not the highest, in maximum credit limit calculation. As a final proposal, FirstEnergy aims to eliminate First Mortgage Bonds due to liquidity concerns. FirstEnergy contends that the proposed ICRT and MTM modifications protect against supplier default and energy market movements, while the other changes strengthen collateral requirements to further mitigate risk.

{¶ 91} The Companies also propose administrative changes to simplify the CBP, including adopting a single master supply agreement (MSA) per supplier, eliminating ink signatures and notarization, removing additional pre-bid security for bidders with foreign guarantors, easing restrictions on back-up bidding, and allowing flexibility in the auction schedule. These changes aim to streamline the process without customer impact, facilitating supplier participation. The Companies request the Commission's approval for their proposed CBP plan and enhancements without modification.

{¶ 92} Staff opposes the proposal to modify the credit-based tranche caps for bidders in the SSO auctions. Staff explains that the proposal would reduce bidding eligibility based on credit ratings, and Staff does not believe that the Companies have justified the proposal. Rather, Staff argues that the credit-based tranche caps should stay the same as ESP IV, which would allow for more robust and diverse participation in the SSO auctions.

{¶ 93} Constellation opposes the proposal to eliminate pre-bid collateral for bidders with foreign guarantors, noting that the security is needed because foreign currency values change over time. As to the proposals to adopt a single MSA and other streamlining proposals, Constellation supports those proposals. (Constellation Ex. 11 at 32.)

{¶ 94} We find the proposals by the Companies to be generally reasonable to help streamline the process and mitigate various risks. However, we adopt Staff’s recommendations, noting that the credit-based tranche caps should stay the same as ESP IV, which will permit greater participation in the auctions.

6. TIME-OF-USE RATE

{¶ 95} Direct Energy argues that all customers with an advanced meter should be added to the time-of-use rate as a default with the ability to opt out. Additionally, Direct Energy suggests a rate design that bills on-peak and off-peak rates for customers with an advanced meter (Tr. Vol. VIII at 1611-12). Direct Energy explains that Time-of-Day rate options in Rider GEN have been available to customers on an opt-in basis for several years (NRG Ex. 1 at 5; Case No. 20-50-EL-ATA). Arguing that time-varying rates are superior, Direct Energy asserts that these types of rates better align prices with costs and reduce peak demand (NRG Ex. 1 at 8, 10; Tr. Vol. XII at 2331). Direct Energy asserts that customers are less likely to opt in to a different type of rate, noting that only 144 residential customers and no commercial or industrial customers have opted in (NRG Ex. 1 at 6). Direct Energy argues that this change would benefit the distribution grid and improve reliability. Direct Energy adds that other jurisdictions have successfully implemented time-varying rates as the default (Direct Energy Ex. 1 at Ex. B).

{¶ 96} Staff responds that this proposal would be a dramatic change from the status quo, which would require a more holistic evaluation and input from all stakeholders. Staff adds that it would be problematic to implement this proposal now because not all customers have smart meters, so it would lead to unequal treatment. However, Staff does note that there are several options for customers seeking time varying rates, including Rider CPP, Rider RTP, Rider RCP, and Rider HLF. Staff suggests possible improvements, such as bill information detailing money savings or loss or providing a rate calculator for customers to estimate savings/costs associated with a time varying rate. Staff recommends that the Companies meet with interested parties within 90 days to discuss opportunities to improve rider design and that the Companies should file an application to update these riders within 120 days. (Staff Ex. 4 at 9, 12-13.)

{¶ 97} We do not find NRG's proposal to be appropriate at this time. Time varying rates could cause significant price shock depending on customer usage, and many customers are not fully educated about how a time varying rate would affect their costs or how to optimize their usage to save more on their bills under time-of-use rates. We acknowledge that few customers currently participate in time varying rate options and agree with Staff that the Companies should explore options to improve rider design, which could lead to greater participation. We also agree with Staff that further efforts are needed to educate consumers on the potential benefits of time varying rates and on how to maximize any savings from such rates. We believe that this approach could increase participation for customers who may benefit from the different rate design without moving large swaths of customers to a different rate design who may not be knowledgeable about it and whose bills could increase dramatically under time varying rates.

H. Rate of Return

{¶ 98} FirstEnergy's existing rate of return (ROR) is 8.48 percent, cost of debt is 6.54 percent, and return on equity (ROE) is 10.5 percent. *In re the Application of Ohio Edison Co., The Cleveland Electric Illum. Co., and The Toledo Edison Co for Authority to Increase Rates for Distribution Service*, Case No. 07-551-EL-AIR et al., Opinion and Order (Jan. 21, 2009) at 21-23. FirstEnergy seeks to continue utilizing these rates (Co. Ex. 3 at 3; OCC Ex. 5 at 3-4).

{¶ 99} NOAC and CUB assert that the continuation of FirstEnergy's 10.5 percent ROE is unreasonable. These parties add that the 10.5 percent rate was set 16 years ago, and the Companies did not present evidence that the rate is just and reasonable (OCC Ex. 5 at 4; Co. Ex. 3 at 3). As evidence that the rate is unreasonable, NOAC and CUB note that Staff Witness Healey stated that the rate is "stale," and OCC Witness Buckley testified that the ROR is not reflective of returns of electric utilities in recent years (Staff Ex. 10 at 5; OCC Ex. 5 at 3-4). CUB adds that capital investment riders, such as Rider DCR, which can lock in costs for years, should undergo a rate case rather than approving Rider DCR for the length of the ESP (Staff Ex. 10 at 8).[11] Specifically, CUB asks that the Commission decline to lock in rates without the full rate case analysis.

{¶ 100} OCC contends that the proposed ROR is too high because the ROE is unreasonably high (OCC Ex. 5 at 3). OCC contends that a fair ROE should be comparable to returns from similar investments; sufficient for the utility's financial integrity; and adequate to maintain the utility's credit and attract capital, citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Bluefield Water Works v. Public Service Comm.*, 262 U.S. 679 (1923). Looking to that guidance, OCC argues that an appropriate ROE for FirstEnergy would be

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11 This concern will be addressed later in the Opinion and Order.

9.22 percent rather than 10.5 percent. OCC adds that the average ROR for electric utilities nationwide is 6.82 percent over a six-month period in 2023. (OCC Ex. 5 at 7-8.) OCC says that, without reducing the ROE, FirstEnergy would be earning excessive profits until the Commission renders its decision in FirstEnergy's next rate case, to be filed in May 2024.

{¶ 101} FirstEnergy asserts that adjusting the ROR, ROE, or cost of debt in this ESP proceeding would go against Ohio Supreme Court and Commission precedent. FirstEnergy states that the Ohio Supreme Court and Commission have consistently rejected arguments that a ROR should be recalculated in between base rate cases. FirstEnergy states that the Commission determined it would use the ROR from the most recent base rate case rather than calculating a new ROR, citing *In re the Application of The East Ohio Gas Company dba Dominion Energy Ohio for Approval of an Alternative Form of Regulation*, Case No. 19-468-GA-ALT (*Dominion CEP Case*), Opinion and Order (Dec. 30, 2020) at ¶ 79. FirstEnergy further notes that when OCC appealed that decision, the Ohio Supreme Court affirmed the Commission's ruling, citing *In re Application of East Ohio Gas Co.*, 2023-Ohio-3289. FirstEnergy adds that OCC's methodology is inconsistent with the longstanding Commission practice to use traditional models in its analysis (OCC Ex. 5 at JPB-1; Tr. Vol. XI at 1973-74, 1962-63).

{¶ 102} It is the Commission's established practice not to recalculate a utility company's ROE and ROR outside of the company's base rate case. *See AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at ¶ 73; *Dominion CEP Case*, Opinion and Order (Dec. 30, 2020) at ¶ 79; *In re The East Ohio Gas Company d/b/a Dominion Energy Ohio*, Case No. 20-1634-GA-ALT, Opinion and Order (Apr. 20, 2022) at ¶ 54. This well-established approach has been affirmed by the Ohio Supreme Court. *In re Application of East Ohio Gas Co.*, 2023-Ohio-3289, ¶ 21. However, to ease concerns that these rates will be "locked in" for the duration of ESP V, we can confirm that the ROR and ROE will be adjusted for all riders when we determine what the new rates will be in the Companies' upcoming base rate case. For these reasons, we decline to adjust the Commission-approved ROR and ROE until the Companies' next base rate case.

I. Rider DCR

{¶ 103} The Companies assert that Rider DCR, as proposed, will help allow the timely cost recovery of investments and maintenance work that facilitate the Companies' ability to continue providing reliable electric service and meeting customers' reliability expectations, while at the same time offsetting degradation of plant-in-service (Co. Ex. 3 at 7). The Companies explain that Rider DCR provides an opportunity to earn a return of and on plant-in-service[12] associated with distribution, transmission, general, and intangible plant which was not included in the rate base from the Companies' last distribution rate case, plus associated taxes, using the most recent authorized ROR. Importantly, any capital additions that are recovered elsewhere in the Companies' rates are excluded from Rider DCR (Co. Ex. 3 at 3). The Commission first approved Rider DCR in the Companies' second ESP, making Rider DCR effective as of January 1, 2012. *In re the Application of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co. for Authority to Establish a Standard Service Offer*, Case No. 10-388-EL-SSO (*ESP II Case*), Opinion and Order (Aug. 25, 2010) at 11. Subsequently, the Commission reapproved and continued Rider DCR, with modifications, in its third and fourth ESPs. *In re the Application of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co. for Authority to Establish a Standard Service Offer*, Case No. 12-1230-EL-SSO (*ESP III Case*), Opinion and Order (Jul. 18, 2012) at 34, 56, Second Entry on Rehearing (Jan. 30, 2013) at 22-23; *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 25, 92-93. In those proceedings, the Companies aver that the Commission found that Rider DCR is authorized by R.C. 4928.143(B)(2)(h), which expressly permits an ESP to include provisions regarding "distribution infrastructure," further recognizing the various benefits associated with such riders, including supporting reliable electric service. *See ESP III Case*, Second Entry on Rehearing (Jan. 30, 2013) at 23, 56.

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[12] Plant in-service included in Rider DCR is offset by accumulated depreciation reserve, accumulated deferred income taxes and applicable excess deferred income taxes resulting from the Tax Cuts and Jobs Act.

{¶ 104} The Companies propose to continue Rider DCR through ESP V with a notable change. Since its inception, Rider DCR has been subject to annual revenue caps. The Companies' Application proposes that the amount of the annual increase in those caps will depend on the Companies' reliability performance results from the prior year and will be limited to increases of approximately 1.5 to 2.1 percent of current base distribution revenues (Co. Ex. 3 at 4; Staff Ex. 8 at 3; Tr. Vol. XIV at 2418). For purposes of the revenue cap determination, the Companies will rely on their individual Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI) results. As explained by FirstEnergy witness McMillen, if all six of the CAIDI and SAIFI reliability standards are met in a given year, the aggregate revenue cap increase in the next year will be $21 million;[13] if five of six are met in a given year, the aggregate revenue cap increase in the next year will be $19 million; if four of six are met, the aggregate revenue cap increase in the next year will be $17 million. (Co. Ex. 3 at 4-5.) However, if the Companies fail to meet at least four of the CAIDI or SAIFI standards, the aggregate revenue cap increase will be reduced to $15 million[14] (Co. Ex. 3 at 5).

{¶ 105} As noted above, FirstEnergy claims that many components of the existing Rider DCR will be carried over to ESP V. For instance, FirstEnergy notes that the individual company annual revenue caps will continue to be the following percentages of the aggregate revenue caps: Ohio Edison at 50 percent, CEI at 70 percent, and Toledo Edison at 30 percent. Further, consistent with its prior ESPs, FirstEnergy states that the revenue caps will continue

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13 The proposed annual aggregate revenue cap increases of $21 million that would apply if all six reliability standards are met are based on the Companies' actual revenue requirements. The Companies' aggregate revenue requirement, based on rate base values as of November 30, 2017, was $275 million and was $383 million based on rate base values as of November 30, 2022, which is an average annual increase of approximately $21 million over the five-year period. (Co. Ex. 3 at 5-6.)

14 The proposed reduced annual aggregate revenue cap increase of $15 million that would apply if the Companies fail to meet at least four of the reliability metrics is based on the average annual increases in depreciation and property tax expenses during 2017 and 2022. The Companies' depreciation and property tax expense increased from $474 million as of November 30, 2017, to $545 million as of November 30, 2022. (Co. Ex. 3 at 6.)

to be applied cumulatively from Rider DCR's inception. (Co. Ex. 3 at 5.) In addition to being subject to annual revenue caps, FirstEnergy also claims that Rider DCR will continue to be updated and reconciled quarterly and subject to annual audits conducted by an independent, third-party auditor selected by the Commission, the proceedings during which Staff and other stakeholders will be provided an opportunity to review the quarterly updates and actively participate in the annual audit proceedings (Co. Ex. 3 at 4). FirstEnergy argues that the quarterly updates and annual audits will continue transparency for customers, as well as provide a more in-depth evaluation of specific Rider DCR investments than what would occur in a base rate case, given their more focused scope of review. Relatedly, FirstEnergy claims that these updates and annual audits will afford parties a more regular opportunity to review and verify the reasonableness of Rider DCR investments, which may not occur if these investments were recovered through base rates. (Co. Ex. 3 at 6-8.) Finally, the Companies note that the Rider DCR mechanism results in reduced regulatory lag, better aligning the costs customers pay with the Companies actual distribution investments. Further, the audits described above may result in reconciliations, including the opportunity for refunds, or credits to customers, which the Companies opine would not be available if the Companies' distribution investments were solely recovered in base rates (Co. Ex. 3 at 7). Additionally, speaking to the annual revenue caps, FirstEnergy argues that Rider DCR, as proposed, is designed to mitigate bill impacts and promote gradualism in rates, continuing predictable and gradual rates through ESP V (Co. Ex. 3 at 4-6). *See also, ESP IV Case*, Fifth Entry on Rehearing (Oct. 12, 2016) at ¶¶249-50; *ESP III*, Second Entry on Rehearing (Jan. 30, 2013) at 22-23.

{¶ 106} Finally, the Companies contend that Rider DCR supports distribution investments to maintain safe and reliable service to customers as well as the Companies' continuing ability to meet customer expectations regarding reliability (Co. Ex. 9 at 13). Citing the testimony of FirstEnergy witness Richardson, the Companies argue they regularly invest in their distribution systems to prevent and limit the duration of outages due to system degradation, system growth, and demand, and expect to continue making capital investments during the term of ESP V at levels comparable to their historic investment levels (Co. Ex. 9 at 13). During the evidentiary hearing, the Companies noted that, while it will be challenging to meet their reliability standards going forward,[15] continued investment in and maintenance of their distribution system will be imperative to sustain that performance (Co. Ex. 9 at 4-5, 9; Tr. Vol. VII at 1380-81). The Companies assert that Rider DCR will help facilitate such investment in their distribution system, adding that the annual revenue caps will be directly tied to the Companies' reliability performance, committing the Companies to investments that will assist them will meeting their reliability metrics (Co. Ex. 3 at 4-5). Further, once their upcoming base rate case is approved, the Companies anticipate that the rate base and revenue caps for Rider DCR will be re-set to zero and that all applicable inputs for Rider DCR will be updated going forward. Accordingly, as Rider DCR is authorized by R.C. 4928.143, directly supports reliability of the Companies' distribution system, and includes important customer protections, the Companies contend that the Commission should approve Rider DCR as proposed, without modification.

{¶ 107} Staff agrees that Rider DCR should be continued, but alternatively suggests that the Commission approve the rider on an interim basis for the period June 1, 2024, through the effective date of the new base rates in the Companies' 2024 base rate case (Bridge Period), with any further continuation of Rider DCR to be addressed in that case. If FirstEnergy fails to file a base distribution rate case in May 2024, Rider DCR should be set to zero as of June 1, 2024 and not be increased for the duration of ESP V, which provides an added incentive to comply with the Commission's directive to file a rate case in May 2024. (Staff Ex. 10 at 9.) Staff notes that, at that time, stakeholders would have the opportunity to raise their arguments for, or against, the continuation of Rider DCR after the Bridge Period. In the event the Commission makes no ruling in that case to continue Rider DCR, Staff

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15 The Companies note that they face several challenges to meet reliability standards, including diverse service territories with varying geographic features, tree-caused outages, supply chain issues, and anticipated load growth (Co. Ex. 9 at 8-9).

proposes that Rider DCR be set to zero when those new base rates would become effective. (Staff Ex. 10 at 10-11.)

{¶ 108} Regardless if the Commission chooses to adopt Staff's initial recommendation to approve Rider DCR on an interim basis through the Bridge Period, Staff avers that several changes to the rider mechanism are necessary.[16] First, Staff argues that, consistent with all other Ohio EDUs' similar riders, the Companies should be allowed to recover only distribution plant investments in FERC Accounts 360-374, and should no longer be permitted to include transmission plant, general plant, intangible plant, or service company plant in the Rider DCR revenue requirement (Staff Ex. 8 at 5, 7-8; Staff Ex. 10 at 10-11). Specifically, citing testimony admitted at hearing, Staff claims that removing plant from other accounts would lower the current $390 million cap by about $51 million to a total of $339 million (Staff Ex. 10 at Attach. CH-1; Co. Ex. 3 at 4). Staff recommends that while the next rate case is pending, the cap could increase by $15 million to $21 million annually to account for new investments in FERC Accounts 360-374, tied to meeting reliability metrics as proposed by the Companies. Staff witness Healey also testified that, by eliminating these other types of investments from the period while the rate case remains pending, ratepayers could save $45 million or more as compared to ESP IV and $75 million or more as compared to the Companies' Application (Staff Ex. 10 at 11-12). Thus, in the first year of ESP V, Staff recommends an initial DCR cap of between $354 and $360 million,[17] which it claims represents a more reasonable recovery of reliability-focused capital investments.

{¶ 109} Similarly, Staff argues that the Companies should not be allowed to include projected plant-in-service in Rider DCR. Currently under ESP IV, Staff observes that the Companies can prematurely recover investments because they file quarterly updates to

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16 Staff ultimately supports 11 separate modifications to the current Rider DCR mechanism.

17 Staff notes its calculation is based on a starting point of $339 million, accounting for the removal of plant outside FERC Accounts 360-374, plus the $15-$21 million increase (Staff Ex. 10 at 10).

Rider DCR based on expected, rather than actual, plant investments. Staff asserts that there is no need to use expected plant investments, as quarterly updates already allow for near-immediate recovery and the Companies' investment projections have been inaccurate in the past, with Staff witness Mackey noting in the quarterly Rider DCR filings from October 2021 until January 2023 "the annual revenue requirement during each quarter was over-estimated by a combined $20.8 million, with all but one quarter over-estimated by at least $3 million" with the following quarter's error being even greater at $13.3 million. (Staff Ex. 8 at 8-9.) As such, Mr. Mackey recommends that the Commission reject FirstEnergy's proposal to use projected plant-in-service balances in calculating the revenue requirement for Rider DCR. Again, Staff notes that FirstEnergy's rider should be consistent with similar distribution riders that the Commission has approved for AEP Ohio, AES Ohio, and Duke Energy Ohio, which only recover actual, not projected, plant balances. (Staff Ex. 8 at 18.)

{¶ 110} As its next recommendation, Staff claims that FirstEnergy's cumulative approach to rolling over unused revenue cap amounts to the next year, or carrying overage to the next year, is unique from other electric utility capital recovery. In order to promote consistency among electric utilities, Staff suggests that this aspect of the rider should be eliminated, and the caps established for each year should be treated as "hard caps," not susceptible to fluctuation based on prior years' outcomes. (Staff Ex. 8 at 9-10.) Next, upon approval of rates in a base rate case, Staff also asserts that the Companies should be required to update Rider DCR with any inputs updated in the rate case, such as ROR or class allocations. As noted by Staff and several other parties in this proceeding, the inputs are currently tied to the Companies' 2007 base rate case (Staff Ex. 8 at 10). Additionally, Staff suggests that the Companies should be required to add a revenue true-up schedule to Rider DCR, as the only true-up currently utilized is to reconcile the prior filing's estimated revenue requirement with the actual revenue requirement in the filing, which is also consistent with other Ohio electric utilities (Staff Ex. 8 at 11-12). Next, Staff alleges that the current allocation and rate design for Rider DCR is unnecessarily convoluted and suggests that it should be simplified to be charged as a percentage of base distribution revenues (Staff

Ex. 8 at 12). Further, to ensure sufficient time for review, Staff recommends that the Companies be ordered to file their proposed Rider DCR rates at least 60 days prior to the effective date (Staff Ex. 8 at 12-13). If this timeframe is not honored, Staff suggests that the rider should consequently be set to zero three months after the effective date of the prior quarterly filing until the Companies are able to meet the imposed deadline on a future Rider DCR filing, with any foregone revenues being permanently excluded from recovery (Staff Ex. 8 at 13). Speaking on the timing of the required quarterly filings, Staff requests that the dates certain should be pushed back one month to accommodate the last filing as having a date certain of December 31st. According to Staff, this will simplify the annual review process as these filings would correspond with the Companies' FERC Form 1 filing, which uses plant balances through December 31st. (Staff Ex. 8 at 14.) According to Staff, when the Companies have historically exceeded their annual Rider DCR cap, they have reduced the revenue requirement for just one of the three Companies to get below the cap. Instead, Staff suggests that the Companies should be required to reduce each of the three Companies' revenue requirements proportionately. (Staff Ex. 8 at 15.) Rather than maintain the individual company annual revenue caps, as suggested by the Companies, Staff recommends that the individual company annual revenue caps be modified to more closely reflect the allocation of plant investments among the three Companies, equating to 60 percent for CEI, 65 percent for Ohio Edison, and 15 percent for Toledo Edison. Staff asserts its alternative caps would still provide the Companies with enough flexibility to spend on each of the three Companies as needed. (Co. Ex. 3 at 5; Staff Ex. 8 at 16.) Further, if the Companies make any changes to their capitalization policy, Staff suggests they should be required to notify Staff of the change and provide documentation and an explanation of the new or revised policy (Staff Ex. 8 at 16).

{¶ 111} Finally, if the Commission ultimately determines that Rider DCR should be approved beyond the Bridge Period, or for the duration of ESP V, then Staff suggests that the Commission should approve $15-21 million increases as annual caps for the full ESP V term, using Staff's starting point of $339 million. As noted by Staff witness Mackey, imposing Staff's recommended caps could save customers more than $300 million over six years as compared to the Companies' proposed caps. (Staff Ex. 8 at 2-5.)

{¶ 112} Despite FirstEnergy's claims to the contrary, OMAEG, OCC, and Kroger contend that FirstEnergy has not adequately demonstrated that a continuation or expansion of Rider DCR is just and reasonable. As such, these parties request that the Commission discontinue FirstEnergy's Rider DCR and, instead, require that prudently incurred distribution costs be recovered through base distribution rates. (OMAEG Ex. 1 at 22; OCC Ex. 1 at 20; Kroger Ex. 1 at 9.) As admitted by FirstEnergy witness Fanelli, OMAEG, Kroger, and OCC emphasize that it has been over 16 years since the Companies' last distribution rate case was filed (Tr. Vol. I at 176; Co. Ex. 2 at 5; OMAEG Ex. 1 at 14; Kroger Ex. 1 at 8; Staff Ex. 10 at 5). As such, OMAEG, Kroger, and OCC argue that continuing collection of incremental distribution costs and incremental increases to distribution rates, absent a review of those costs through a distribution rate case, is not reasonable or prudent (OMAEG Ex. 1 at 14; OCC Ex. 1 at 20). *In re the Application of Columbus S. Power Co.*, Case Nos. 08-917-EL-SSO, et al., Opinion and Order (Mar. 18, 2009) at 32. OMAEG, OCC, and Kroger maintain that Rider DCR essentially equates to impermissible single-issue ratemaking and that the kinds of costs being recovered through Rider DCR can, and should, instead be recovered through base rates because they are base distribution costs (OMAEG Ex. 1 at 13; Kroger Ex. 1 at 8; OCC Ex. 1 at 16, 19, 32; Co. Ex. 3 at 5; Tr. Vol. II at 391). According to OMAEG, FirstEnergy even acknowledged that "the costs in Rider DCR would be recoverable even if the rider was not effective." (Co. Ex. 3 at 8). As such, OMAEG, Kroger, and OCC argue that the Commission should require that base distribution costs only be recovered through base distribution rates because rate case filings take into consideration both FirstEnergy's costs and its revenues to determine whether FirstEnergy needs to collect additional funds from customers to provide its services (OMAEG Ex. 1 at 14; OCC Ex. 1 at 18-19; Kroger Ex. 1 at 8-9). With an imminent rate case application, OCC, OMAEG, and Kroger allege that proceeding will be the more appropriate forum to determine the appropriate level of capital investment recovery (OMAEG Ex. 1 at 14; OCC Ex. 1 at 13, 19-20; Tr. Vol. XIV at 2613).

{¶ 113} OMAEG also contends that FirstEnergy has failed to demonstrate that Rider DCR is statutorily permissible to be included in ESP V. OMAEG notes that the Supreme Court of Ohio has previously held that R.C. 4928.143(B)(2) allows an ESP to include only "any of the following" provisions enumerated, not "any provision" that the utility might devise. *See In re the Application of Columbus S. Power Co., et al.*, 128 Ohio St.3d 512, 520, 947 N.E.2d 655 (2011) (internal quotations omitted). While R.C. 4928.143(B)(2)(h) states that an ESP may provide for or include "provisions regarding . . . incentive ratemaking," OMAEG asserts that Rider DCR cannot qualify as such. In discussing incentive ratemaking, the Court has previously determined that "incentive ratemaking uses rewards and penalties that link utility revenues to various standards or goals." "[I]f the commission awards [a utility] money up front with no meaningful conditions attached," then it cannot be considered an "incentive." *In re the Application of Ohio Edison Co., Cleveland Electric Illum. Co., and Toledo Edison Co.*, 157 Ohio St.3d 73, 2019-Ohio-2401, 131 N.E.3d 906 at ¶¶17, 19. According to OMAEG, allowing FirstEnergy's Rider DCR to guarantee an amount collected from customers, which would increase every year by at least $15 million, would not qualify as an "incentive" given that there are no penalties associated with FirstEnergy's ability to achieve various standards or goals. Contrarily, since FirstEnergy has been consistently meeting its reliability performance standards for over a decade, OMAEG argues Rider DCR is essentially an award of an additional $21 million annually that will not change FirstEnergy's practices moving forward. As such, OMAEG contends does not fall within any of the categories enumerated in R.C. 4928.143(B)(2) and, thus, cannot be incorporated in the ESP.

{¶ 114} Further, OMAEG, OCC, and Kroger assert that EDU and customer expectations about the EDU's distribution system must be aligned if the Commission is to include, for instance, a distribution investment rider in an ESP, pursuant to R.C. 4928.143(B)(2)(h). Despite this requirement, OMAEG claims that FirstEnergy did not sufficiently demonstrate that its expectations and the expectations of its customers are aligned as it relates to the reliability of the distribution system. OMAEG and Kroger cite FirstEnergy witness Richardson's testimony, in which she recognized that the Companies' distribution system is currently reliable, and the Companies have consistently met or exceeded Commission-approved reliability standards. In fact, these parties state that, since 2010, FirstEnergy has never failed to meet its reliability performance standards for two consecutive years. (Co. Ex. 9 at 2, 8; Staff Ex. 5 at 4; Tr. Vol. VII at 1378-79.) However, according to OMAEG, no FirstEnergy witness provided evidence that the customer surveys conducted during 2021 specifically addressed whether customers agree with Rider DCR and whether additional charges imposed for improved reliability are warranted or whether customers are satisfied with the cost to serve them (Tr. Vol. VII at 1371-85). OMAEG and Kroger argue that additional investments for improved reliability, absent research supporting the necessity of such investments as suggested by OCC witness Meyer, are not prudently incurred costs and should not be recoverable from ratepayers (OCC Ex. 1 at 20).[18] As a result, OMAEG, Kroger, and OCC claim there is a disconnect between the Companies' and customers' expectations that cannot be remedied without further research. Therefore, OMAEG, Kroger, and OCC assert Rider DCR is unable to satisfy the statutory requirement contained in R.C. 4928.143(B)(2)(h) and should be rejected accordingly.

{¶ 115} Finally, OMAEG and OCC claim that FirstEnergy has failed to demonstrate the need for Rider DCR, let alone annual revenue cap increases of up to $21 million. As noted during the evidentiary hearing, FirstEnergy spends approximately $400 million[19] each year on its distribution system and, again, has been successfully meeting its reliability standards for over a decade (Co. Ex. 3 at 4; Co. Ex. 9 at 8; Tr. Vol. VII at 1380). OMAEG and OCC also note that FirstEnergy witness Richardson conceded that, even if Rider DCR is not extended for another eight years, FirstEnergy is still expected to meet its reliability

18 OCC witness Meyer "recommend[s] that the Commission perform an extensive review of the necessity for this special infrastructure mechanism and determine if Rider DCR should continue for the entire ESP V planning horizon. A cost benefit analysis should be required of FirstEnergy to continue Rider DCR," but "Rider DCR should not become a permanent rider for FirstEnergy."

19 This amount only includes amounts recovered through Rider DCR and does not include expenditures on grid modernization, vegetation management, or storm restoration.

standards (Tr. Vol. VII at 1380). OMAEG and OCC add that FirstEnergy witness McMillen agreed that, even without Rider DCR, FirstEnergy is still required to provide adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service (Tr. Vol. II at 406). Furthermore, OCC claims it is unjust and unreasonable to link the amounts of the annual revenue increases to enhanced reliability performance because FirstEnergy cannot prove that any reliability improvements stem from increased Rider DCR spending. As noted above, OCC, Kroger, and OMAEG contend the Companies would not be harmed through the discontinuation of Rider DCR, as these costs are recoverable through base rates (Co. Ex. 3 at 3, 5, 8; Tr. Vol. II at 391, 409; Tr. Vol. XIV at 2618). OMAEG and Kroger assert that, while the exact amount of each annual revenue cap increase depends on whether the FirstEnergy utilities meet their reliability metrics, even if all three utilities fail to meet their reliability metrics, the Application proposes to guarantee an annual revenue cap increase of $15 million, resulting in the collection of at least $510 million from customers in the eighth year of ESP V (Tr. Vol. I at 73; Tr. Vol. II at 392-93; Co. Ex. 3 at 5). OCC also emphasizes that the $21 million annual increase is also higher than the $15 million annual increase historically allowed by the Commission. *ESP II Case*, Opinion and Order (Aug. 25, 2010); *ESP III Case*, Opinion and Order (July 18, 2012); *ESP IV Case*, Fifth Entry on Rehearing (Oct. 12, 2016). According to OMAEG and Kroger, the increase in revenue caps, as well as the extension of Rider DCR for another eight-year term, could result in charges to customers totaling up to $3.876 billion over the term of ESP V (Staff Ex. 8 at 5; Tr. Vol. XIV at 2442, 2564). Moreover, OMAEG reiterates that FirstEnergy has not justified a $15–$21 million annual revenue cap increase, given that the Companies have admitted that they "have had a strong history of meeting, and in many cases exceeding, their reliability performance standards." (Co. Ex. 9 at 2; Staff Ex. 5 at 4; Tr. Vol. I at 178; Tr. Vol. VII at 1378-79). OCC also claims FirstEnergy's Rider DCR proposal is unjust and unreasonable because FirstEnergy failed to include a depreciation offset, which would allow FirstEnergy to earn excess profits for Rider DCR spending based on a level of plant investment that is overstated (OCC Ex. 1 at 32-33). Moreover, OCC argues that the Commission has approved such a depreciation offset in certain capital expense rider cases. *In re the Application of Duke Energy*

Ohio, Inc., Case No. 19-791-GA-ALT, Opinion and Order (Apr. 21, 2021). According to OCC, this offset would protect consumers by calculating the revenue requirement based on the same type of approach used in a traditional distribution base rate case (OCC Ex. 1 at 33).

{¶ 116} Based on the evidence and testimony presented, OMAEG, OCC, and Kroger assert that Rider DCR, as proposed, does not meet statutory requirements, and includes unnecessary, unreasonable, and imprudent rate increases for customers. Therefore, these parties request that the Commission reject the proposed Rider DCR and require FirstEnergy to file a base distribution rate case when and if it requests to collect additional funds from customers for distribution investments (OMAEG Ex. 1 at 14). Alternatively, if the Commission does not reject Rider DCR as proposed by OMAEG, Kroger, and OCC, these parties suggest that, at a minimum, the Commission should modify Rider DCR in accordance with Staff's proposed modifications, which significantly decrease the costs passed on to customers and collected through Rider DCR. Additionally, OCC suggests that, if the Commission approves any annual revenue increases for Rider DCR, the level of annual increase should be the same as what has traditionally been approved, or $15 million annually.

{¶ 117} Though it advocates for the elimination of several riders, including Rider DCR, Walmart alternatively supports Staff's proposal for Rider DCR and approve recovery only for the Bridge Period. NOAC also advocates for the elimination of Rider DCR, and at the very least, a reduction in the yearly increases in the annual revenue cap, agreeing with parties that argued that FirstEnergy will need to meet its reliability standards even without the existence of Rider DCR.

{¶ 118} As to the generalized argument that the Commission should defer ruling on the Companies' distribution riders, including Rider DCR, beyond the Bridge Period until the 2024 base rate case, the Companies respond by noting that there is no Commission precedent to support, nor statutory authority to authorize, modifying an ESP application in such a way (Tr. Vol. XIV at 2616). R.C. 4928.143I(1). Instead, the Companies observe that the Commission has successfully adjudicated ESPs notwithstanding pending or upcoming base rate case applications. *See, e.g., ESP I Case*, Opinion and Order (Dec. 19, 2008) at 35. Further, the Companies note that approving Rider DCR for less than the full term of the ESP would diminish the benefits associated with ESP V and would ultimately result in rate uncertainty for ratepayers (Tr. Vol. XIV at 2615). FirstEnergy also notes that it would have to evaluate the impact of this modification and whether it would need to exercise its statutory right to withdraw the ESP. R.C. 4928.143I(2)(a). The Companies again argue that, despite parties insisting that the base rate case would be the most appropriate forum to consider these riders, there are many notable benefits associated with the proposed rider mechanisms, including, but not limited to: a reduction in regulatory lag in the recovery of distribution investments which enables proactive management of the distribution system; more frequent and thorough reviews by Staff and the Commission;[20] and, given that many of the distribution riders, including Rider DCR, will employ rate caps, the promotion of rate certainty, stability, and predictability (Tr. Vol. I at 104; Tr. Vol. III at 562-63; Tr. Vol. XIII at 2219; Tr. Vol. XIV at 2400, 2409-10, 2604-05). FirstEnergy notes that Staff witness Healey admitted that he could not identify any type of review of the Companies' investments in a rate case that would not be completed as part of the routine annual rider audits (Tr. Vol. XIV at 2611). Moreover, the Companies acknowledge that the applicable inputs for certain riders, such as ROE, cost of debt, capital structure, depreciation rates, revenue requirement allocations, etc., will be updated and reset in the 2024 base rate case.

{¶ 119} In response to Staff's suggested modifications, the Companies argue that Staff's recommendations for additional penalties if the Companies fail to make timely filings should also be rejected as they are unnecessary, as well as excessive in nature. Additionally, the Companies contend that discontinuing the rollover effect currently utilized in Rider DCR overlooks the purpose of the cap, which is to provide a fixed limit on the amounts that

20 The Companies also note that interested stakeholders are permitted to participate in audit proceedings, including through filing comments and issuing discovery (Tr. XIV at 2604-05).

can be recovered under Rider DCR on a cumulative basis, adding that the caps are not amounts the Companies are guaranteed to collect. As such, FirstEnergy emphasizes that the Companies will not be able to recover more than the sum of the annual cap increases over the term of ESP V. (Tr. Vol. I at 90, 94.) *ESP III Case*, Opinion and Order (July 18, 2012) at 34. The Companies also oppose numerous recommendations to modify the treatment of property and income taxes in Rider DCR, noting that the recommendations are inconsistent with the Companies' most recent base rate case and Rider DCR filings. Finally, FirstEnergy asserts that reducing the aggregate annual revenue caps for Rider DCR by $51 million throughout the Bridge Period by limiting Rider DCR to only include FERC Accounts 360-374 should be rejected. The Companies claim this proposal would eliminate nearly 15 percent of their Rider DCR revenue, or $51 million annually, and such a significant reduction in the currently authorized cost recovery contradicts Rider DCR's long-established terms and conditions (Staff Ex. 8 at 5; Staff Ex. 10 at 9-10; Tr. Vol. XIV at 2396, 2403, 2428-29, 2622). *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 93; *see also In re the Quadrennial Review Required by R.C. 4928.143(E) for the Electric Security Plans of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case No. 20-1476- EL-UNC, et al. (*Global Settlement Case*), Opinion and Order (Dec. 1, 2021). In fact, FirstEnergy notes that Staff acknowledges that there have been no changes to the costs eligible for inclusion in Rider DCR since it was originally approved (Tr. Vol. XIV at 2395). In addition, FirstEnergy asserts the proposed modification would discontinue the Companies' ability to recover those costs even though there has been no finding that the costs are unreasonable in the 12 annual audit proceedings that have occurred since Rider DCR's inception (Staff Ex. 8 at 7). The Companies argue that the costs of these investments support the provision of distribution service, noting that Staff agreed that these investments include, among other things, transmission voltage transformers and wires, line shops, garages, buildings where distribution employees work, service vehicles, information technology systems, and other essential parts of the distribution system (Tr. Vol. XIII at 2227-29; Tr. Vol. XIV at 2402-2406). Despite the reasonableness of these costs, FirstEnergy alleges that the proposed modification will prevent the Companies from having an opportunity to recover these costs during the Bridge Period, due to Commission-approved base distribution rate freezes, which predate Rider DCR. *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 92. Further, the Companies note that the decision in the *Global Settlement Case* addressed any concerns related to excessive earnings resulting from ESP IV and provided $306 million in benefits to the Companies' customers, including $210 million in rate reductions over the period December 31, 2021 through December 31, 2025, continuing well beyond ESP IV's expiration and into the Bridge Period. The Companies aver the settlement in that case balanced these benefits with other interests, including continuing Rider DCR in its current form. The Companies suggest an additional elimination of $51 million in annual cost recovery over the 2024-2025 time period, with no opportunity for the Companies to recover their costs in the interim, would disrupt the balanced compromise adopted in the *Global Settlement Case*. Finally, the Companies allege that the immediate reduction of $51 million in recovery per year would challenge their ability to continue investing in their distribution system to support the provision of reliable electric service (Co. Ex. 9 at 10-12). While recognizing Staff's objective to align capital investment recovery riders among Ohio EDUs, FirstEnergy notes that the above factors should be considered to determine the timeframe in which this goal should materialize. Nonetheless, FirstEnergy notes that there are other differences among the Ohio EDUs' ESPs, as well as other material differences that may justify treating them differently, such as FirstEnergy's base rate freeze that has been in effect since 2009 (Tr. Vol. XIV at 2414, 2425). *ESP I Case*, Second Opinion and Order (Mar. 25, 2009) at 11; *ESP II Case*, Opinion and Order (Aug. 25, 2010) at 25; *ESP III Case*, Opinion and Order (July 18, 2012); *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 92.

{¶ 120} As an alternative, the Companies suggest limiting Rider DCR to FERC Accounts 360-374 only after the effective date of new base distribution rates, with the Companies continuing to include the costs of investments outside of those FERC accounts in Rider DCR through the Bridge Period. Further, the Companies suggest that the balances of those accounts could remain frozen at May 31, 2024 levels so there is no growth beyond the ESP IV term. This alternative approach would allow the Companies to continue recovering the costs of these investments, subject to annual audits and applicable revenue caps, until they can be included in base distribution rates. After those new base distribution rates would go into effect, the Companies would then reset Rider DCR to zero and, thereafter, would only include FERC Accounts 360-374, consistent with other utilities, with annual revenue cap increases of $15 million to $21 million for the remaining ESP V term.

{¶ 121} Initially, the Commission notes that, although the new leadership of FirstEnergy Corp. understands the need for increased transparency and accountability, the Companies have gone far too long without a base distribution rate case, which allows for a comprehensive view of the Companies' rates. This delay is solely the responsibility of the Companies, who agreed to rate case stay-out provisions in each of their prior ESPs. Since the filing of FirstEnergy's last rate case in 2007, each of the other EDUs in this state have filed at least two base distribution rate cases.

{¶ 122} Moreover, we agree with the testimony of Staff witness Healey, who stated that "riders should not become the primary form of cost recovery for utilities to the exclusion of base distribution rate cases" (Staff Ex. 10 at 7). Therefore, pursuant to our policy that the major electric and natural gas utilities should have regular, periodic rate cases, we have implemented rate case directives, with appropriate enforcement mechanisms, for these utilities. *AES ESP IV Case*, Opinion and Order (Aug. 9, 2023) (utility directed to file new rate case by December 31, 2025); *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) (utility directed to file new rate case by June 1, 2026); *In re Columbia Gas of Ohio, Inc.*, Case No. 21-637-GA-AIR (*Columbia Rate Case*), Opinion and Order (Jan. 26, 2023) at ¶95 (utility directed to file new rate case by September 1, 2027); *In re Vectren Energy Delivery*, Case No. 18-298-GA-AIR, Opinion and Order (Aug. 28, 2019) (utility directed to file new rate case by December 31, 2024); *Duke ESP IV Case*, Opinion and Order (Dec. 19, 2018) (utility directed to file new rate case by May 31, 2023). We find that FirstEnergy's ESP V should include a similar appropriate directive. Accordingly, we will modify the proposed ESP V and direct FirstEnergy, as a term or condition of ESP V, to file a distribution rate case no later than May

31, 2028, in addition to the distribution rate case currently required to be filed by May 31, 2024 (Tr. Vol. XIV at 2560).

{¶ 123} Further, we agree with the testimony of Staff witness Healey that, as long as distribution rate cases are filed in a regular, periodic manner, adjustable rate clauses (riders) can prove to be beneficial to customers and in the public interest. Mr. Healey testified that allowing cost recovery through a rider can give the utility an added incentive to make investments that are beneficial to customers and the grid, such as investments targeting reliability improvements (Staff Ex. 10 at 5-6). Moreover, the recovery of investments through riders helps reduce the regulatory lag associated with the recovery of investment through distribution base rate cases; OCC witness Collins agreed that by avoiding regulatory lag, distribution riders encourage investments by the utility to proactively address reliability (Tr. Vol. XIII at 2219). Mr. Healey also testified that riders can promote gradualism in rate increases, providing for more frequent but smaller rate increases (Staff Ex. 10 at 6-7).

{¶ 124} We also note that Staff witness Healey testified that riders can be used to provide benefits between rate cases by giving customers dollar-for-dollar reductions if the utility's costs decrease or providing credits to customers that might otherwise be unavailable (Staff Ex. 10 at 6-7). OCC witness Collins conceded that this is an appropriate use of riders (Tr. Vol. XIII at 2214-2216).

{¶ 125} In addition, the Commission rejects OCC's claim that riders in general receive less regulatory scrutiny. OCC refers to no evidence in support of this claim. The riders approved in this ESP in general will be subject to periodic audits by the Staff or a third-party auditor on behalf of Staff. There is no evidence that these audits provide less regulatory scrutiny than a distribution rate case; OCC witness Collins conceded that, even in the absence of a rate case, utilities are still at risk of disallowance for costs recovered through riders if such riders are subject to regular update and reconciliation. Mr. Collins also agreed that reconciliations which include refunds ensure that utilities only recover amounts actually invested, preventing over-recovery from customers. (Tr. Vol. XIII at 2220). In fact, the periodic audits of riders routinely result in disallowances and adjustments, which in some cases, can be substantial. *See In re Application of The Dayton Power and Light Co.*, Case Nos. 12-3062-EL-RDR et al., Opinion and Order (Dec. 17, 2014) at 13-14 (reduction in recovery of storm damage expenses from $37 million to $22.3 million); *In re Application of Duke Energy Ohio, Inc.*, Case No. 09-1946-EL-RDR, Opinion and Order (Jan. 11, 2011) at 23-24, aff'd, 131 Ohio St.3d 487, 2012-Ohio-1509 (reduction in recovery of storm damage expenses from $28.4 million to $14.1 million).

{¶ 126} Accordingly, we are not persuaded by the recommendations by OCC, OMAEG and Kroger that we should reject the continuation of existing riders or establishment of new riders under the proposed ESP V.

{¶ 127} Turning to the arguments specifically pertaining to Rider DCR, the Commission finds that Rider DCR is statutorily authorized through R.C. 4928.143(B)(2)(h), which expressly permits single issue ratemaking as part of an ESP. We note that Rider DCR was first approved by the Commission in FirstEnergy's ESP II and has been in effect since January 1, 2012. *ESP II Case*, Opinion and Order (Aug. 25, 2010) at 11; *ESP III Case*, Opinion and Order (July 18, 2012) at 34; *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 111. Rider DCR ensures that the Companies can make necessary investments in the distribution infrastructure to maintain reliability by reducing the regulatory lag for recovery of those investments. *ESP III Case*, Second Entry on Rehearing (Jan. 30, 2013) at 23; *ESP IV Case*, Fifth Entry on Rehearing (Oct. 12, 2016) at ¶250. Further, we find OMAEG's reliance on *Ohio Edison* is misplaced, as that decision was premised on FirstEnergy's Distribution Modernization Rider, which is wholly separate and distinct from Rider DCR. *Ohio Edison*, 157 Ohio St.3d 73, 77, 2019-Ohio-2401, 131 N.E.3d 906. Rather than receiving funds regardless if any capital investment is made, the Companies are only authorized through Rider DCR to recover capital investments that are actually made and are subsequently subject to rigorous annual audits by Staff to confirm customers only pay for actual investments in used and useful property, similar to the other Ohio EDUs' capital investment riders. *See In re the Application of Duke Energy Ohio, Inc.*, Case No. 14-181-EL-SSO, Opinion and Order (Apr. 2, 2015) at 178; *In re the Application of Duke Energy Ohio Inc., for an Increase in Electric Distribution Rates*, Case No. 17-32-EL-AIR, Opinion and Order (Dec. 19, 2018) at ¶294. Rider DCR is also expressly subject to refund if the Commission determines a disallowance should be made in the underlying audit proceedings. Further, as emphasized by both Staff and FirstEnergy, Rider DCR does include an incentive component, as the annual Rider DCR cap decreases by up to $6 million per year, depending on FirstEnergy's reliability performance. With the potential reduction of funds collected through Rider DCR, the Companies will have an added incentive to meet their reliability performance metrics. We also note that we agree with Staff that customer reliability expectations are aligned with the Companies' performance and the Companies are placing sufficient emphasis on reliability, consistent with the statute (Staff Ex. 5 at 6).[21] Notably, no party, including OMAEG, has offered any Commission or Supreme Court of Ohio precedent that has found a capital investment rider like Rider DCR is unlawful under the governing statute, including the *Ohio Edison* decision discussed above. Thus, Rider DCR, as proposed by both the Companies and Staff, is lawful under R.C. 4928.143(B)(2)(h).

{¶ 128} Relatedly, the Commission is not persuaded by claims by OCC, OMAEG, and Kroger that costs under Rider DCR fail to receive proper scrutiny or less scrutiny than would otherwise be available in a rate case. These distribution investments are necessary to maintain distribution reliability at current levels. *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 93. As we have stated previously, Rider DCR is subjected to annual audits which require the Companies to demonstrate what they spent and why the recovery sought is not unreasonable. *ESP III Case*, Opinion and Order (Jul. 18, 2012) at 34; *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 111. As noted by the Companies, the Commission has been

[21] The record evidence demonstrates that the Companies have all met their SAIFI for the last five years and have generally met their CAIDI over the same period. Specifically, Ohio Edison exceeded the CAIDI standard in 2019, and CEI exceeded CAIDI in 2022. Additionally, Staff asserts that CEI and Toledo Edison are projected to miss their CAIDI standards in 2023. (Co. Ex. 9 at 5; Tr. VII at 1381.)

conducting such audits annually since the inception of Rider DCR. Thus, all parties have had, and will continue to have, a full and fair opportunity to raise any issues regarding distribution investments to be recovered under Rider DCR during the audit process. We additionally note that, in these Rider DCR audit proceedings, the burden is on the Companies to demonstrate that its expenditures are incremental, prudent, and consistent with the Commission's orders, rules, and Ohio statutes.

{¶ 129} Further, in ESP IV, the Commission specifically observed that in light of the proposed distribution rate freeze, it is necessary and appropriate to continue the existing Rider DCR mechanism, which allows the Companies to recover reasonable investments in plant in service, which were not included in the rate base of the Companies' last distribution rate case. *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 93. However, once new base rates are in effect, the Commission agrees with Staff that these expenses should be zeroed out and the Commission will be able to evaluate, on a more holistic basis, "the Companies' expense, revenues, rate of return, and potentially all those factors and others could inform the Commission's decision on the level of DCR that it believes is appropriate" (Tr. Vol. XIV at 2613; Staff Ex. 10 at 5-6). As such, the Commission will approve the rider on an interim basis for the Bridge Period, with any further continuation of Rider DCR to be addressed in upcoming rate case. We, however, do agree that Staff's recommendation to zero out Rider DCR in the event the Companies fail to file their base rate application by May 31, 2024 is unduly excessive. The Commission has significant discretion in imposing a variety of penalties in the event a utility company fails to abide by one of our directives, including, but not limited to, our ability to assess forfeitures under R.C. 4905.54.

{¶ 130} As to what costs will remain permissible under Rider DCR through the Bridge Period while the rate case application remains pending, the Commission also agrees with Staff's recommendation to no longer allow investments outside of FERC Accounts 360-374 (Staff Ex. 8 at 5, 7-8; Staff Ex. 10 at 10-11; OCC Ex. 1 at 2-23). Both Staff and FirstEnergy agree that the elimination of these investments in Rider DCR will result in a $51 million reduction from the current cap of $390 million to a total of $339 million (Staff Ex. 10 at Attach.

CH-1; Co. Ex. 3 at 4). Notably, Staff witness Healey testified that, by removing these other types of investments from the period while the rate case remains pending, ratepayers could save $45 million or more as compared to ESP IV and $75 million or more as compared to the Companies' Application (Staff Ex. 10 at 11-12). This change would amount to considerable savings for FirstEnergy's customers and will further align FirstEnergy's recovery of distribution-related expenses with those of other Ohio EDUs. (OCC Ex. 1 at 2-23 Staff Ex. 8 at 8-9, 18). *See, e.g., AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023) at ¶77; *Duke ESP IV Case*, Opinion and Order (Dec. 19, 2018) at ¶114; *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at 35. Further, while the upcoming rate case is pending, the Commission also finds reasonable to allow the cap to increase by $15 million to $21 million annually to account for new investments in FERC Accounts 360-374, tied to whether FirstEnergy fails to meet its reliability metrics as proposed by the Companies in its Application. While the Companies raised various concerns regarding the "elimination" of the $51 million through the Bridge Period, we note the Companies are required to "furnish necessary and adequate service and facilities," as well as meet their Commission-approved reliability metrics. R.C. 4905.22; Ohio Adm.Code 4901:1-10-10. Accelerated recovery of these types of expenses should not dictate whether they are made. The Companies will have the opportunity to demonstrate what they believe to be an appropriate revenue requirement for Rider DCR it the upcoming rate case, which will provide a more comprehensive and holistic basis for our analysis. *ESP IV Case*, Eighth Entry on Rehearing at 39 (Aug. 16, 2017) (where the Commission agreed "with Staff … that it is sound regulatory practice to conduct regular distribution rate cases"). Additionally, we agree that the Commission was in no way bound by the *ESP IV Case* or *Global Settlement Case* regarding the existence or underlying terms for Rider DCR going forward in ESP V. Indeed, no such terms were contemplated in either of those proceedings. In any event, the Commission has previously indicated that proposed or anticipated terms reached in a settlement to be raised in subsequent Commission proceeding have no bearing on the Commission's decision in that subsequent proceeding. *Duke MGP Proceedings,* Opinion and Order (Apr. 20, 2022) at ¶¶ 121, 126. The Companies' Application for ESP V was not filed until April 5, 2023, and is currently pending before us. It is in the context of this Application that we have evaluated the record evidence presented to determine the appropriate rate caps and other terms that should apply to Rider DCR through ESP V. Moreover, as noted above, it is FirstEnergy's burden to demonstrate its Application is reasonable. Based on the record evidence, we find Staff's recommendation to allow the Rider DCR mechanism to recover up to $360 million in charges in the first year of ESP V to be reasonable. While that amount may be less than what is currently collected under ESP IV, that fact alone does not make our finding unreasonable or contradictory to prior Commission decisions. Thus, in the first year of ESP V, we adopt Staff's suggested initial DCR cap of between $354 and $360 million.

{¶ 131} Similarly, the Commission also finds Staff's recommendation to disallow the Companies from including projected plant-in-service in Rider DCR to be appropriate. We agree that the current requirement to file quarterly updates, which the Companies are proposing to continue through ESP V, dispels the need to utilize expected plant investments (Staff Ex. 8 at 8-9). Further, the Commission finds that utilizing actual plant-in-service will also help eliminate inaccurate projections that have resulted in over-estimated revenue requirements in the past, reducing the need for unnecessary fluctuations in rates through reconciliation (Staff Ex. 8 at 8-9). Again, the Commission notes that it is reasonable to attempt to achieve consistency between Ohio EDUs, when possible, and similar distribution riders that the Commission has approved for AEP Ohio, AES Ohio, and Duke Energy Ohio only recover actual plant balances (Staff Ex. 8 at 18). Noting another opportunity for further consistency between the capital investment riders of FirstEnergy and the other Ohio EDUs, Staff has suggested that FirstEnergy's cumulative approach utilized with the Rider DCR revenue caps should also be modified (Staff Ex. 8 at 9-10). *See, e.g., AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at 35; *AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023) at ¶ 77. OCC, OMAEG, and Kroger note their support for this modification, and we agree that it should be adopted at this time (OCC Ex. 1 at 27). Moreover, the Companies should be required to add a revenue true-up schedule to Rider DCR, as suggested by Staff, which is also consistent with other Ohio electric utilities (Staff Ex. 8 at 11-12). FirstEnergy has not provided any basis for why these three particular issues should not be treated uniformly between the EDUs.

{¶ 132} Finally, the Commission agrees with several of the rate design and filing requirements proposed by Staff witness Mackey, including charging Rider DCR as a percentage of distribution revenues and modifying the sub-caps for each of the Companies to more accurately reflect the allocation of plant investments among them[22] (Staff Ex. 8 at 12-16). However, while Staff suggests that the rider should be set to zero and foregone revenues be precluded from recovery in the event the new 60-day timeframe for the Companies' updated Rider DCR rates is not adhered to, this would be overly punitive. Though we believe the Companies will follow the new timeframe adopted in this Order, we quickly note that, in the event Staff does not believe they have had sufficient time to review the filing due to the untimeliness of the Companies, Staff may still request that the new rates be suspended until it is ready to complete its review. Accordingly, the Companies' Rider DCR proposal should be approved, as modified herein.

J. Rider AMI

{¶ 133} The Companies propose to continue Rider AMI for the term of ESP V to continue supporting the Companies' grid modernization initiatives. According to the Companies, Rider AMI currently recovers costs associated with the Ohio Site Deployment of the Smart Grid Modernization Initiative in Case No. 09-1820-EL-ATA (Ohio Site Deployment), as well as the costs of the Companies' first phase of their grid modernization business plan, approved in Case No. 16-481-EL-UNC, et al. (Grid Mod I). The Companies propose to continue Rider AMI, under its current terms and conditions, for the term of ESP V. As such, the Companies propose that, unless otherwise directed by the Commission, cost

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22 Staff witness Mackey recommends the following caps: 60 percent for CEI, 65 percent for Ohio Edison, and 15 percent for Toledo Edison.

recovery for Grid Mod I through Rider AMI will continue, consistent with current Commission authorization. Further, FirstEnergy notes that Rider AMI would also be used to recover costs of additional approved grid modernization programs. (Co. Ex. 3 at 9.) Finally, FirstEnergy also commits to Rider AMI being subject to quarterly updates and reconciliation as well as annual audits by Staff, consistent with the audit process approved in ESP IV and Grid Mod I (Co. Ex. 3 at 10).

{¶ 134} The Companies argue that Rider AMI directly supports the Companies' investments in grid modernization programs, which have been designed to support enhanced reliability of the Companies' distribution system (Co. Ex. 9 at 13). FirstEnergy also asserts that, in approving Rider AMI in ESP IV, the Commission recognized its value, finding that Rider AMI is supported by Ohio policy and is consistent with "efforts to make the grid more reliable and cost effective for customers." *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 96. The Companies note that R.C. 4928.143(B)(2)(h) provides that an ESP may include "provisions regarding distribution infrastructure and modernization incentives," adding that Rider AMI clearly falls within this permissible category as it supports investments that make more granular usage data available to customers and market participants, encouraging cost-effective, timely, and efficient access to such data and promoting customer choice (Co. Ex. 3 at 10).

{¶ 135} In addition to supporting reliability and modernization of its distribution system, the Companies also aver that Rider AMI includes consumer protections and benefits. Similar to the arguments for Rider DCR, FirstEnergy notes that Rider AMI supports enhanced transparency to customers, the Commission, and other interested parties through quarterly updates and annual audits, in the latter of which the Companies are required to demonstrate that the investments included in recovery are both prudent and used and useful (Co. Ex. 3 at 10). *See In re the Application of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case No. 16-481-EL-UNC, et al. (*Grid Mod I Case*), Opinion and Order (July 17, 2019) at ¶ 91. Reiterating many of the same points it made for Rider DCR, FirstEnergy argues that the current Rider AMI mechanism will allow for a more timely review of investments than may otherwise occur if these costs were recovered in base rates, will allow for a more focused audit specifically aimed to review the costs included in Rider AMI, and will better align costs customers pay with the Companies' investments through quarterly updates, fostering gradualism (Co. Ex. 3 at 10). Accordingly, as Rider AMI is expressly authorized under R.C. 4928.143, includes important customer protections, and supports increased reliability of the Companies' distribution system, the Companies request that the Commission approve the continuation of Rider AMI without modification.

{¶ 136} Staff agrees with continuing Rider AMI with various modifications.[23] First, similar to its recommendation for Rider DCR, Staff asserts the Companies should be required to eliminate the use of projected plant-in-service and expenses from the rider, which would arguably increase accuracy and align Rider AMI with similar riders approved for other utilities (Staff Ex. 8 at 18). Next, Staff argues that the Companies should not be allowed to recover any additional costs associated with the Ohio Site Deployment in Rider AMI and should remove the "Provisions" section from the tariff, as the Commission only approved recovery of such costs through June 1, 2019 (Staff Ex. 8 at 18-19). Third, upon approval of new rates in the Companies' upcoming rate case, Staff asserts that the Companies should not be allowed to recover Ohio Site Deployment or Grid Mod I plant-in-service or expenses in Rider AMI, contending that they have had sufficient time to complete these investments and are, in fact, no longer making Grid Mod I capital investments (Staff Ex. 8 at 19). Further, to provide Staff sufficient time for review, Staff also recommends that the Companies should be required to file each quarterly Rider AMI filing at least 60 days in advance of the effective date of the tariff, similar to its recommendation for Rider DCR (Staff Ex. 8 at 20). Finally, Staff suggests that the annual audit of Rider AMI may be completed by a third-party auditor, with the costs of such audit paid for by the Companies but eligible for recovery in the rider (Staff Ex. 8 at 21).

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[23] Overall, Staff suggests seven separate modifications to the Companies' proposal pertaining to Rider AMI.

{¶ 137} OMAEG and OCC support Staff's recommendation that costs related to Grid Mod I and the Ohio Site Deployment should be rolled into FirstEnergy's base rates in the upcoming rate case (Staff Ex. 10 at 12; Staff Ex. 8 at 19; OCC Ex. 1 at 38; Tr. Vol. II at 412, 416, 433-34; Tr. Vol. XIV at 2437). OMAEG emphasizes that the Companies plan to collect, in aggregate, "approximately $450 million . . . through Rider AMI through the next five years," which does include the projected Grid Mod II costs (Tr. Vol. II at 423-24; OMAEG Ex. 8). However, in the 11 years between 2011 and 2022, OMAEG claims FirstEnergy only collected $369,632,768 from customers for Grid Mod I and Ohio Site Deployment-related costs (RESA Ex. 8; Tr. Vol. II at 386-88). As to Staff's recommendation regarding Ohio Site Deployment costs, OMAEG supports this modification, arguing that Staff has routinely opposed the collection of these costs since 2019 and the Commission recently determined that the capital portion of the Ohio Site Deployment costs should not be recovered through Rider AMI (Tr. Vol. XIV at 2437-38, 2444, 2448; Staff Ex. 8 at 18).

{¶ 138} Noting another inconsistency between Riders DCR and AMI, OCC also takes issue with the fact that FirstEnergy's Rider AMI proposal lacks revenue caps for spending, which could lead to excessive Rider AMI spending (OCC Ex. 1 at 10, 38-39). In addition to the noted internal inconsistency of the proposal, OCC adds that the lack of revenue caps is also inconsistent with Commission precedent for other riders for the collection of capital costs from customers. *AES Ohio ESP IV Case*, Opinion & Order (Aug. 9, 2023) at ¶ 77; *Duke ESP IV Case*, Opinion and Order (Dec. 19, 2018); *In re the Application of Ohio Power Co. for Authority to Establish an SSO,* Case No. 16-1852-EL-SSO, et al. (*AEP Ohio ESP IV Case*), Opinion and Order (Apr. 25, 2018). Citing the testimony of its witness, Mr. Meyer, OCC also argues that FirstEnergy failed to provide compelling arguments why collecting the cost of replacing customer meters through Rider AMI is necessary (OCC Ex. 1 at 38). Finally, OCC argues that Rider AMI is unjust and unreasonable and contrary to R.C. 4909.15(A), as it allows FirstEnergy to continue earning a return on and of stranded grid modernization equipment even after the equipment is removed from service. *In re Application of Suburban Natural Gas Co.*, 166 Ohio St.3d 176, 2021-Ohio-3224, 184 N.E.3d 44. OCC claims the meters and associated equipment removed from service are not providing service because they have been replaced, and thus are not "used and useful," and, consequently, should be prohibited to recover under R.C. 4909.15(A). (OCC Ex. 1 at 39-40.)

{¶ 139} Although it advocates for the elimination of several riders, including Rider AMI, Walmart alternatively suggests incorporating Staff's proposal for Rider DCR and only approving recovery of Rider AMI costs for the Bridge Period. Walmart also notes that Staff witness Healey stated that Rider AMI would also be considered in the upcoming base rate case (Staff Ex. 10 at 12-13). Walmart believes that it would be appropriate to place safeguards similar to those proposed by Staff for Rider DCR.

{¶ 140} In response to the various modifications related to Rider AMI, the Companies find Staff's proposal to eliminate the use of projected plant from Rider AMI is reasonable but suggest rejecting all other recommendations to modify Rider AMI. For instance, contrary to OCC's claim that Rider AMI is not subject to revenue caps, FirstEnergy notes that the Companies *Grid Mod I Case* established caps on capital and O&M expense recovery,[24] which the Companies are not proposing to alter or eliminate. *Grid Mod I Case*, Opinion and Order (July 17, 2019) at ¶¶32, 92, 97, 118. Relatedly, the Companies state that the Commission also authorized recovery through Rider AMI of the costs associated with the net book value of retired meters in Grid Mod I. *Grid Mod I Case*, Opinion and Order (July 17, 2019) at ¶¶71, 93. Although it does not respond to Staff's recommendation that FirstEnergy should not be able to recover any additional costs associated with the Ohio Site Deployment through Rider AMI, FirstEnergy does contest not being able to recover Grid Mod I costs through Rider AMI, unless and until the Commission authorizes their recovery through base rates, consistent with the authority granted in ESP IV. *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 23.

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24 The recovery of capital costs and incremental O&M expense is capped at $516 million and $139 million, respectively.

{¶ 141} The Commission finds that Rider AMI should be approved, as modified by Staff's recommendations. Consistent with our adoption of a similar recommendation for Rider DCR, the Commission finds that the Companies should be required to eliminate the use of projected plant-in-service and expenses from Rider AMI, which would align Rider AMI with similar riders approved for other utilities (Staff Ex. 8 at 18). *AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023); *Duke ESP IV Case*, Opinion and Order (Dec. 19, 2018); *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024). Staff also contends that the Companies should not be allowed to recover any additional costs associated with the Ohio Site Deployment, as the Commission only authorized recovery of such costs through June 1, 2019 (Staff Ex. 8 at 18-19). *In re the Application of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case No. 09-1820-EL-ATA. We agree. The Commission recently issued a decision relating to the 2017 and 2018 annual reviews of Rider AMI. *In re the Application of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case Nos. 16-2166-EL-RDR, et al., (*2017/2018 Rider AMI Review*) Finding and Order (Nov. 16, 2023). While the Commission did not opine on costs beyond June 1, 2019 in that proceeding, as that date went beyond the scope of the years under review, we did discuss at length the history behind the Ohio Site Deployment pilot program and emphasized the significance of the Commission's prior decisions related to that program. Specifically, the Commission found that the Companies' last application for authority to recover costs related to the program appeared to be limited to the O&M costs associated with ongoing data collection for an additional four-year collection period, ending June 1, 2019. *2017/2018 Rider AMI Review*, Finding and Order (Nov. 16, 2023) at ¶38. A reading of the decision in the *2017/2018 Rider AMI Review* would undoubtedly result in the same outcome regarding expenses incurred beyond the June 1, 2019 deadline. Relatedly, Staff also argues that, upon approval of new rates in the Companies' upcoming rate case, the Companies should not be allowed to recover Ohio Site Deployment or Grid Mod I plant-in-service or expenses in Rider AMI (Staff Ex. 8 at 19). This is a reasonable suggestion, given our discussion above relating to the benefits of a holistic analysis in rate case proceedings, and we emphasize that the Companies will still be able to recover these otherwise recoverable costs through base rates at that time. Further, we also find Staff's request for the Companies to file each quarterly Rider AMI filing at least 60 days in advance of the effective date of the tariff, similar to its recommendation for Rider DCR, to be reasonable (Staff Ex. 8 at 20).

{¶ 142} As discussed above, the ROR and ROE will be adjusted for all riders when we determine what the new rates will be in the Companies' upcoming base rate case; however, the Companies should continue to utilize those approved in its most recent base rate case until that time, consistent with long-standing Commission precedent (Staff Ex. 8 at 21). *See, e.g., AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at ¶75; *Dominion CEP Case*, Opinion and Order (Dec. 30, 2020) at ¶¶ 68-69, Second Entry on Rehearing (Feb. 23, 2020) at ¶20; *In re Application of East Ohio Gas Co.*, 2023-Ohio-3289 (Sept. 20, 2023); *In re Columbia Gas of Ohio, Inc.*, Case No. 17-2202-GA-ALT, Opinion and Order (Nov. 28, 2018) at 16; *In re Ohio Power Company's Implementation of the Tax Cuts and Jobs Act of 2017*, Case No. 18-1007-EL-UNC et al., Finding and Order (Oct. 3, 2018).

{¶ 143} Finally, we note that the Companies have filed an application that is currently pending before the Commission for Grid Mod II. *Grid Mod II Case*, Application (July 15, 2022). That case is currently set for hearing, in which all interested parties will be able to participate and raise their respective arguments related to the Companies' application and the joint stipulation filed in that proceeding. *Grid Mod II Case*, Joint Stipulation (Apr. 12, 2024).

K. Rider SCR

{¶ 144} FirstEnergy proposes to continue its current storm cost deferral mechanism and implement Rider SCR, a new rider, to recover major storm costs. FirstEnergy asserts that Rider SCR is authorized pursuant to R.C. 4928.143 and will support storm restoration efforts and be consistent with other EDUs' storm riders, citing *AEP Ohio ESP IV Case*, Opinion and Order (Apr. 25, 2018), *Duke ESP IV Case*, Opinion and Order (Dec. 19, 2018), *AES Ohio ESP IV Case,* Opinion and Order (Aug. 9, 2023). The Companies state that Rider

SCR would be used to recover from or return to customers the deferral amount, which would mitigate the regulatory lag (Co. Ex. 7 at 4). The Companies explain that Rider SCR will provide enhanced transparency with annual updates and audits that would allow for more immediate customer refunds, if due (Co. Ex. 7 at 7). Other benefits include insulation from rate shock due to annual rate caps, according to FirstEnergy (Co. Ex. 7 at 5-6).

{¶ 145} Kroger asks the Commission to reject Rider SCR because the costs can be recovered through base distribution rates (Co. Ex. 3 at 20, 22; Tr. Vol. II at 391, 443, 445; Tr. Vol. VI at 1279; Kroger Ex. 1 at 4; OCC Ex. 1 at 11-12). OMAEG and Kroger suggest that Rider SCR is not needed to ensure reliability because the Companies have been consistently meeting and exceeding their reliability metrics (Tr. Vol. I at 178; Tr. Vol. VII at 1378-79; Co. Ex. 9 at 2, 8-9). OMAEG adds that Rider SCR costs are more appropriately addressed in a rate case (OCC Ex. 1 at 15). OCC notes that the Pennsylvania Public Utilities Commission rejected a similar storm rider because storm damage can be included in base rate cases or for abnormal expenses with deferred accounting and subsequent recovery in base rate filings, citing *In re FirstEnergy and GPU Merger Savings Remand Proceeding*, Case No. R-00061366, et al., Opinion and Recommended Decision, 2006 Pa. PUC LEXIS 116 (Oct. 31, 2006) at 315-316. Staff responds that although some storm costs should be recovered through base rates, Staff supports the use of riders for recovery of some incremental storm costs above the baseline included in base rates.

{¶ 146} OCC argues that Rider SCR, and riders in general, can harm consumers because OCC claims that the charges to consumers receive less regulatory scrutiny. OCC and Kroger allege that utilities benefit from the decline in legacy rate base, and riders can reduce a company's incentive to control costs (OCC Ex. 1 at 9-10). Kroger also notes that these charges should be holistically examined in a base rate case before costs are recovered through Rider SCR. OMAEG adds that allowing Rider SCR would reduce FirstEnergy's incentive to control costs, which would be detrimental to customers (OCC Ex. 1 at 12). NOAC asserts that multiple accounts would make it possible to double charge expenses or choose the account with the best economic advantage, which makes the expenses difficult to audit. Specifically, NOAC contends that Rider SCR and Rider VMC would include similar expenses. (Staff Ex. 2 at 7-8.)

{¶ 147} NOAC suggests that Rider SCR be eliminated, which it argues would improve accountability and auditability. OMAEG claims that, because Rider SCR does not incentivize any new behavior from FirstEnergy, Rider SCR does not meet any category in R.C. 4928.143(B)(2) and cannot lawfully be implemented in ESP V. Kroger agrees, arguing that Rider SCR does not provide an incentive to the Companies because Kroger alleges that FirstEnergy's behaviors and practices will not change in response to the payments. OCC adds that FirstEnergy has an excess of riders, so the Commission should not approve new Rider SCR (OCC Ex. 1 at 10-11). If the Commission approves Rider SCR, Kroger, OMAEG, and OCC ask that it be approved subject to Staff's recommendations (Staff Ex. 10 at 30; Staff Ex. 2).

{¶ 148} As to the argument that Rider SCR would be unlawful under R.C. 4928.143(B)(2), Staff explains that argument is inconsistent with the language of the statute and Commission precedent. Specifically, Staff asserts that, while OMAEG singles out the "incentive ratemaking" provision of the statute, there is no requirement that riders can be approved only if they constitute incentive ratemaking, citing *In re the Application of Columbus S. Power Co. and Ohio Power Co. for Authority to Establish a Standard Service Offer*, Case Nos. 11-346-EL-SSO, et al., *In re the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer*, Case Nos. 14-841-EL-SSO, et al. (*Duke ESP III Case*); *In re the Application of The Dayton Power and Light Co. for Authority to Recover Certain Storm-Related Service Restoration Costs*, Case Nos. 12-3062-EL-RDR, et al.

{¶ 149} Consistent with its arguments regarding Rider DCR, Kroger represents that approving Rider SCR constitutes inappropriate single-issue ratemaking, which is contrary to long-standing Commission precedent and policy (Kroger Ex. 1 at 4). OMAEG adds that Rider SCR will be collecting storm-related expenses that could otherwise be recovered through base rates, so Rider SCR constitutes single-issue ratemaking (Co. Ex. 3 at 22; Co. Ex.

7 at 7; Tr. Vol. I at 101; Tr. Vol. II at 445; Tr. Vol. VI at 1279; OMAEG Ex. 1 at 13-15; Kroger Ex. 1 at 9-11; OCC Ex. 1 at 16). In response, Staff notes that R.C. 4928.143(B)(2)(h) allows an ESP to include "provisions regarding single issue ratemaking."

{¶ 150} The Commission finds that the Companies proposal to establish Ride SCR should be adopted, subject to the Staff recommendations discussed below. The evidence in the record demonstrates that Rider SCR will facilitate the timely recovery of storm damage expenses resulting from "major events." Further, Staff witness Borer testified that major events are "highly unpredictable" and "have the potential to cause significant financial harm to a utility" (Staff Ex. 2 at 9-10). As FirstEnergy notes, each of the other EDUs in this state have a similar storm damage recovery mechanism although Staff witness Borer also notes that the other EDUs storm damage rider are limited to "major events" (Tr. Vol., XIII at 2218-2219; Staff Ex 2 at 6-7).

{¶ 151} As noted above, we reject OCC's baseless assertion that riders are subject to less regulatory scrutiny. Rider SCR will be subject to periodic audits by the Staff or a third-party auditor on behalf of Staff. OCC witness Collins conceded that, even in the absence of a rate case, utilities are still at risk of disallowance for costs recovered through riders if such riders are subject to regular update and reconciliation. Mr. Collins also agreed that reconciliations which include refunds ensure that utilities only recover amounts actually invested, preventing over-recovery from customers. (Tr. Vol. XIII at 2220.) In fact, the periodic audits of riders routinely result in disallowances and adjustments, which, in cases involving storm damage recover riders, have been substantial. See *In re Application of The Dayton Power and Light Co.,* Case Nos. 12-3062-EL-RDR et al., Opinion and Order (Dec. 17, 2014) at 13-14 (reduction in recovery of storm damage expenses from $37 million to $22.3 million); *In re Application of Duke Energy Ohio, Inc.,* Case No. 09-1946-EL-RDR, Opinion and Order (Jan. 11, 2011) at 23-24, aff'd, 131 Ohio St.3d 487, 2012-Ohio-1509 (reduction in recovery of storm damage expenses from $28.4 million to $14.1 million).

{¶ 152} Nonetheless, in order to ensure that refunds of Rider SCR be available to customers, we direct FirstEnergy to modify its tariff for Rider SCR, and as well as all new riders authorized under this ESP, to include the language "to the extent permitted by law" in the tariff language providing that Rider SCR be subject to reconciliation, including refunds, as the result of audits conducted by Staff. This is consistent with our decision enunciated in *In re the Application of Dayton Power and Light Co.,* Case No. 08-1094-EL-SSO, Fifth Entry on Rehearing (June 16, 2021) at ¶ 64.

{¶ 153} We also reject Kroger's claim that approval of Rider SCR would result in improper single-issue ratemaking. We do not disagree with Kroger that Rider SCR will result in single issue ratemaking; however, more importantly, we agree with Staff that single issue ratemaking is specifically authorized for distribution provisions in an ESP. Further, we believe that OMAEG is conflating "incentive ratemaking" with "single issue ratemaking," both of which are independently authorized by R.C. 4928.143. R.C. 4928.143(B)(2)(h) states that an ESP may include:

> Provisions 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. * * * As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

The plain language of the statute demonstrates that single issue ratemaking and incentive ratemaking are specifically and independently authorized by the statute. Moreover, the Commission finds that uncontroverted evidence in the record demonstrates that expectations of customers and the EDUs are aligned, as required by R.C. 4928.143(B)(2)(h) (Staff Ex. 5).

1. QUALIFYING STORM DEFINITION

{¶ 154} FirstEnergy's proposed definition of major storms is a storm "anticipated to last longer than 12 hours (using local only crews), including the time to pre-stage personnel for the event" (Co. Ex. 7 at 3). FirstEnergy argues that this definition is appropriate because the Commission has approved this definition for deferral purposes for 14 years, citing *In re the Application of Ohio Edison Co., The Cleveland Illum. Co., and The Toledo Edison Co. for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices, and for Tariff Approvals*, Case No. 07-551-EL-AIR, et al. (*2007 Rate Case*), Opinion and Order (Jan. 21, 2009) at 42-43. FirstEnergy states that in accordance with the stipulation in that proceeding, Staff and the Companies agreed that FirstEnergy could defer expenses from "major storms" with the same definition FirstEnergy proposes for Rider SCR (Co. Ex. 7 at 3). FirstEnergy notes that the Commission approved this definition in ESP III and ESP IV. *ESP III Case*, Opinion and Order (July 18, 2012); *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 77-78, 93, 113. Further, FirstEnergy represents that there is no requirement to utilize the Ohio Adm.Code definition of "major event" for recovery of major storm expenses in the Ohio Revised Code or the Ohio Adm.Code (Tr. Vol. XII at 2180-2181). FirstEnergy points out that storms that do not qualify as a "major event" are also capable of damaging the distribution system. The Companies add that Staff did not consider the financial impact on the Companies if Rider SCR were limited to "major events" (Tr. Vol. XIII at 2182).

{¶ 155} Staff recommends that Rider SCR include only prudently-incurred expenses related to storms that are "major events" as defined by Ohio Adm.Code 4901:1-10-01(T), which would be consistent with storm riders in place for other Ohio EDUs (Staff Ex. 2 at 6-

7). Staff and OCC argue that FirstEnergy's proposed definition would be too vague and could be subject to manipulation or lead to double recovery if routine maintenance occurred around the same time as the storm (Staff Ex. 2 at 7-8). The number of eligible storms could increase by more than 300 percent if the Commission adopts FirstEnergy's definition for storm recovery as compared to Staff's definition, say Staff, OCC, and OMAEG (Staff Ex. 2 at 8-9). Under Staff's proposal, recovery from non-major events would be recovered through base distribution rates (Staff Ex. 2 at 9-10). OCC also states that FirstEnergy's definition would be inconsistent with the existing storm riders in place for other utilities (Staff Ex. 2 at 6-7).

{¶ 156} The Commission finds that Staff's recommendations regarding limiting recovery under Rider SCR to "major events" and the definition of "major events" should be adopted. We are persuaded by the testimony of Staff witness Borror that this recommendation will make Rider SCR, which, again, is a new rider, consistent with the storm damage recovery riders for the other EDUs in this state. Further, Staff's recommendation relies upon the existing defining of "major events" contained in Ohio Adm.Code 4901-1:1-10-01(T). (Staff Ex. 2 at 6-7.) We are not persuaded by the Companies argument that we had previously approved use of a different definition for "major events" in *ESP III* and *ESP IV*. In both of those cases, the Commission approved each stipulation as a package, recognizing that the individual terms and conditions of a stipulation are the product of compromises among the signatory parties. Therefore, the individual terms and conditions of an approved stipulation, in isolation, are of limited precedential value.

2. RIDER CAPS

{¶ 157} FirstEnergy proposes the following annual caps: $16 million for OE, $17 million for CEI, and $2 million for TE (Co. Ex. 7 at 5). As for FirstEnergy's proposed annual recovery caps, Staff states that those caps would be unnecessary if Rider SCR is limited to include recovery of major events, and Kroger supports Staff's position. Kroger and OMAEG challenge FirstEnergy's proposed "soft caps" that would allow revenue carryover from year to year as improper.

{¶ 158} The Commission will adopt Staff's recommendation that there be no annual caps on the recovery of storm damage costs under Rider SCR (Staff Ex. 2 at 10), until the effective date of new rates in FirstEnergy's forthcoming distribution rate case. We do not direct a different outcome on this issue in the distribution rate case; the Commission believes that the parties to the distribution rate case should have the ability to revisit the amount and nature of any annual recovery caps, as well as other terms and conditions regarding Rider SCR, in the distribution rate case.

3. EXISTING DEFERRED BALANCE

{¶ 159} FirstEnergy proposes that the current storm balance would be amortized in Rider SCR over a period of five years (Co. Ex. 7 at 6). Staff recommends that the Commission not allow recovery of the currently deferred balance in this proceeding, as proposed by FirstEnergy. Rather, Staff submits that recovery of the deferral balance should be considered in the next rate case or another proceeding (Staff Ex. 2 at 18). Staff proposes this method so that it may evaluate all aspects of the deferral, including the recovery period (Staff Ex. 2 at 19-20). NOAC supports Staff's proposal to audit the deferred storm costs before allowing recovery. Kroger avers that the fourteen years of deferred storm related costs should not be recovered through Rider SCR and should instead be recovered through base rates (Tr. Vol. VI at 1277-78; Co. Ex. 7 at 2; OCC Ex. 1 at 12, 16). As proposed by FirstEnergy, Kroger and OMAEG explain that customers would pay $35 million each year in actual storm expenses and approximately $29.5 million per year for five years to account for the storm cost deferrals (Tr. Vol. I at 75; Co. Ex. 2 at SFL-3; Staff Ex. 10 at 30; Co. Ex. 7 at 2, JL-1; Tr. Vol. VI at 1277-78; Tr. Vol XIII at 2184; Staff Ex. 2 at 17). In its reply brief, FirstEnergy states that it does not object to the recommendation to wait to recover the deferred balance until after the balance has been subject to audit.

{¶ 160} The Commission finds that Staff's recommendation on this issue should be adopted. The existing storm damage deferrals will not be recovered through Rider SCR but will be subject to potential recovery in FirstEnergy's forthcoming distribution rate case.

4. Other Staff Recommendations

{¶ 161} Next, Staff recommends that Rider SCR should not include costs for straight-time, or non-overtime, labor so as to avoid double recovery (Staff Ex. 2 at 12-13). Staff explains that straight-time labor could be recovered in base rates, and this recommendation would be in line with other Ohio EDU's storm riders (Staff Ex. 2 at 13, fn. 8). If the Companies provide mutual assistance with straight-time labor outside the Companies' service territory, Staff recommends that those labor costs should be credited to Rider SCR (Staff Ex. 2 at 14). Staff reasons that would prevent the Companies from being paid twice – through base rates and through mutual assistance payments from the other utility. In response, FirstEnergy states that it only seeks to recover incremental costs and would agree to work with Staff in the annual Rider SCR audits so that Staff can determine that only incremental costs are included in the storm deferral. The Commission finds that Staff's recommendation on this issue should be adopted.

{¶ 162} Staff further submits that there should be no carrying charges applied to major event expenses incurred during ESP V because there would be minimal regulatory lag associated with the recovery of storm costs (Staff Ex. 2 at 16). NOAC asks the Commission to disallow any further interest or carrying charges on the deferred balance because the delay to perform the audit is caused by the Companies. FirstEnergy asks the Commission to allow carrying charges for major storm expenses incurred during ESP V, claiming that regulatory lag would be mitigated but not eliminated, and there are financing costs associated with that spending. Although we disagree with NOAC that the Companies necessarily are responsible for any delays in auditing these expenses, the Commission is not persuaded that carrying charges should be authorized. We agree with Staff that carrying charges should not be necessary because there should be minimal regulatory lag associated with the recovery of storm damage expenses (Staff Ex. 2 at 16). However, nothing precludes the Companies from seeking carrying charges, on a case-by-case basis, where extraordinary circumstances result in an unforeseen delay in the recovery of storm damage expenses.

{¶ 163} Staff also proposes that instead of the annual audit process proposed by FirstEnergy, the Companies should make a single filing in August of each year that includes actual costs for the prior June 1 through May 31 period. Staff further explains that the rates would go into effect automatically after 60 days, subject to the Commission determining otherwise, and the audit would occur in the same proceeding (Staff Ex. 2 at 15).

{¶ 164} As for the existing deferral mechanism, the Companies explain that mechanism is already in place to compare actual storm damage expenses with the test year levels in base distribution rates, and the difference is deferred (Co. Ex. 7 at 3). FirstEnergy seeks to continue this deferral mechanism that has already been approved in ESP IV. Staff recommends that the existing deferral authority cease with ESP V, as the Companies would be able to recover through Rider SCR (Staff Ex. 2 at 7). The Commission agrees with Staff. The existing deferral authority will cease at the conclusion of ESP IV; however, nothing precludes the Companies from seeking to extend that authority in the upcoming distribution rate case.

L. Vegetation Management Program and Rider VMC

{¶ 165} The Companies propose a new rider, Rider VMC, to support their current vegetation management practices, as well as a new Enhanced Vegetation Management Program (EVM Program), to help promote the provision of safe and reliable service to customers. As proposed by the Companies, Rider VMC will recover incremental vegetation management operations and maintenance (O&M) expenses compared to the baseline levels recovered in base distribution rates (Co. Ex. 3 at 19). Additionally, the Application notes that total vegetation management O&M expense recovered through Rider VMC will be capped at $759.8 million for the entire eight-year term of ESP V (Co. Ex. 3 at 21; Co. Ex. 8).

Similar to other riders, the Companies note that Rider VMC will also be subject to annual regulatory update, audit, and reconciliation, including but not limited to increases or customer refunds, based upon audit results (Co. Ex. 3 at 21).

{¶ 166} As proposed, the Companies assert that Rider VMC will foster proactive vegetation management practices and reliability by mitigating regulatory lag in the Companies' recovery of vegetation management O&M expense and supporting the Companies' proposed EVM Program (Co. Ex. 3 at 19). Since 2014, the Companies have experienced an increase in tree-caused outages of 104 percent, as well as significant increases in SAIFI (Co. Ex. 8 at 6). Due to this significant increase, the Companies note that they began a review in 2019 to determine the cause and discovered that most of the tree-caused outages in the Companies' territories were attributable to off-right-of-way (off-ROW) trees, making up approximately 80 percent of the identified outages (Co. Ex. 8 at 7). According to the Companies, the EVM Program will address the Companies' most frequent cause of outages and improve reliability for all customers by expanding the scope of priority tree identification and removal, focusing on removing on- and off-corridor trees, removing overhang, and controlling brush in the distribution clearing zone more proactively. (Co. Ex. 8 at 9.) FirstEnergy claims this program will also lead to significant reliability improvement, estimating a six to seven percent estimated reduction in the Companies' average SAIFI and CAIDI standards (Co. Ex. 8 at 13). The Companies also argue that the EVM Program is estimated to provide cost savings to customers from reliability improvements of $963 million nominally, or $574 million on a net present value, over the next ten years (Co. Ex. 8 at 15). Given these benefits, the Companies argue that Rider VMC clearly falls within the provisions of an ESP authorized under R.C. 4928.143(B)(2)(h), further adding that the Commission has authorized similar vegetation management cost recovery riders as part of other Ohio EDUs' ESPs. *See, e.g., AEP Ohio ESP IV Case*, Opinion and Order (Apr. 25, 2018) at ¶196; *In re the Application of Duke Energy Ohio, Inc.,* Case No. 17-1263-EL-SSO, et al., Opinion and Order (Dec. 19, 2018) at ¶290; *AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023) at ¶184.

{¶ 167} The Companies also aver that the benefits associated with Rider VMC are not limited to improvement in reliability. As with Riders DCR and AMI, the Companies assert that Rider VMC provides customer protections unique to rider mechanisms, including: aligning recovery of vegetation management expenses with the work being conducted; providing enhanced transparency to customers through annual updates, annual audits, and reconciliation; allowing for more timely review of these specific expenses than what might otherwise occur in a base rate case; and mitigating bill impacts and promoting gradualism in rates (Co. Ex. 3 at 21-22). The Companies add that recovery under Rider VMC will also be subject to an overall cap, limiting the amount of costs recovered from customers over ESP V's term and allowing for more predictable rates. With the base rate case to be filed in May 2024, FirstEnergy also notes that further rate mitigation may occur when the inputs resulting from that case are updated (Co. Ex. 3 at 19). The Companies also suggest its EVM Program will create safer conditions for employees and subcontractors, as well as the general public, by reducing the density of brush surrounding the Companies' facilities, making them easier and safer to access and control (Co. Ex. 8 at 8, 13-14). Further, FirstEnergy claims the EVM Program will positively impact the local environment, through maintenance of the right-of-way in an ecologically beneficial manner that will support various insects, animals, birds, and other wildlife (Co. Ex. 8 at 16). Finally, FirstEnergy maintains that the EVM Program will create long-term cost savings for customers, noting that the Companies' vegetation management costs are expected to decrease by 21 percent, or $22 million, in year five of ESP V, and by another 24 percent, or $22 million, in year nine (Co. Ex. 8 at 8, 14). Beginning in that same year, the Companies claim that the EVM Program is also expected reduce storm O&M expenses by an estimated $2 to $3 million per year (Co. Ex. 8 at 14). Arguing that Rider VMC is expressly authorized under R.C. 4928.143(B)(2)(h), will provide substantial benefits to customers, including supporting implementation of the proposed EVM Program, FirstEnergy requests that Rider VMC, and the associated EVM Program, be approved by the Commission as proposed.

{¶ 168} Staff agrees that the Companies should be allowed to recover some vegetation management costs through Rider VMC; however, Staff advocates that such recovery should be capped at an amount sufficient for the Companies to meet their regulatory requirements—an average of about $26 million per year—to be subject to adjustment after the next base rate case. As such, Staff supports approval of Rider VMC caps equal to the following amounts for years one through six, respectively: $22.1 million; $23.7 million, $25.3 million, $26.9 million, $28.6 million, and $30.4 million[25] (Staff Ex. 1 at 6; Co. Ex. 3 at Attach. BSM-4; Co. Ex. 8 at 12). Staff notes its proposal is based on a review of the Companies' recent historical vegetation management spending and reliability performance, further arguing that, if adopted, the proposal would result in a significant reduction in overall charges for customers, noting a $425 million difference between its proposal and that of the Companies.[26] Staff notes that the caps should be reset in the upcoming rate case, where a new baseline will be set based on a holistic view of vegetation management spending (Tr. Vol. XI at 2067). Similar to other riders, Staff also recommends that rates for Rider VMC become effective 60 days after filing, as the deadline proposed by FirstEnergy does not provide sufficient time for Staff to identify issues that may prompt the Commission to suspend the updated rates. Finally, Staff recommends that no carrying charges be applied to Rider VMC rates, as the rider is updated annually and would go into effect 60 days after filing under Staff's proposal. (Staff Ex. 1 at 8.)

{¶ 169} Initially, OCC once again argues that FirstEnergy's reliance on riders decreases its incentive to control and manage its costs. As noted by OCC witness Meyer, FirstEnergy has an average of 54 riders and nine tariff provisions for each of its Ohio utilities and proposes to add three additional new riders in ESP V, one of which being Rider VMC.

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[25] Staff notes that these caps are in addition to the $29.6 million currently recovered under base rates.

[26] If Staff's proposal is adopted, the Companies could charge ratepayers up to $334.6 million over a six-year period through base rates and Rider VMC, compared to the Companies' proposal of $759.8 million over an eight-year ESP term (Co. Ex. 8 at 12; Staff Ex. 1 at 6).

OCC asserts that, simply given the number of FirstEnergy's existing riders, it would be unjust and unreasonable for the Commission to approve FirstEnergy's proposed new riders for storm restoration costs and for vegetation management costs. (OCC Ex. 1 at 9-11.)

{¶ 170} Additionally, OCC, OMAEG, Kroger, OELC, and NOAC argue that FirstEnergy has failed to demonstrate a need for Rider VMC, as it could collect the costs for any enhanced vegetation management program in the upcoming base rate case (OCC Ex. 1 at 15-16, 18-19; OMAEG Ex. 1 at 10, 17; Kroger Ex. 1 at 4, 10; Tr. Vol. XIV at 2618). These parties note that the costs FirstEnergy seeks to recover through Rider VMC would be recoverable through base rates even if the rider was not in effect and, as such, should be rejected (Co. Ex. 3 at 22; Co. Ex. 7 at 7; Tr. Vol. I at 101; Tr. Vol. II at 445; Tr. Vol. VI at 1279). OMAEG notes that Staff already indicated that Rider VMC would necessarily be affected by the upcoming rate case (Staff Ex. 1 at 7; Staff Ex. 10 at 12-13; Tr. Vol. XI at 2067). OMAEG also claims that because this rider does not qualify as an "incentive" under R.C. 4928.143(B)(2)(h), it cannot lawfully be included in ESP V. Accordingly, OCC, OMAEG, Kroger, OELC, and NOAC suggest that these costs be included in the upcoming base rate case (OCC Ex. 1 at 16).

{¶ 171} OMAEG, Kroger, and OELC also question whether Rider VMC is required to improve reliability, as FirstEnergy has been consistently meeting or exceeding its reliability metrics the last decade (Tr. Vol. I at 178; Tr. Vol. II at 1378-79; Co. Ex. 9 at 4-5, 8-9). Moreover, these parties point to FirstEnergy witness Standish's testimony, in which he stated that FirstEnergy is already currently satisfying all applicable regulatory requirements with respect to its existing vegetation management plan (Co. Ex. 8 at 11). OMAEG and Kroger add that FirstEnergy witness Standish further admitted that, without Rider VMC, FirstEnergy would probably not implement the EVM program, indicating that the program is not necessary for FirstEnergy to continue providing safe, reliable, and non-discriminatory electric service (Tr. Vol. VI at 1315). OMAEG contends that FirstEnergy will still need to comply with state law and provide safe and reliable electric service, regardless if the rider is approved (Tr. Vol. VI at 1310). Further, OELC argues that the Rider VMC proposal seeks excessive reliability improvements at ratepayers' expense, noting that FirstEnergy's reliability performance is already aligned with customer expectations and, in fact FirstEnergy's "SAIFI standards and performance thereunder exceed (i.e. are lower than) customer expectations" and FirstEnergy's "CAIDI standards and performance thereunder are also well within the range of customer expectations[.]" (Co. Ex. 9 at 5-7).

{¶ 172} Finally, OMAEG and OELC agree that the Commission should not authorize FirstEnergy's proposed Rider VMC, citing the significant increase of vegetation management costs (Co. Ex. 8 at 11-12). According to OMAEG, FirstEnergy currently spends about $45 million each year on vegetation management costs, recovering approximately $30 million through base rates (Co. Ex. 3 at 19-20; Co. Ex. 8 at 3; Staff Ex. 1 at 5; OMAEG Ex. 1 at 15; Kroger Ex. 1 at 9; Tr. Vol. II at 443). Further, over the past three years, OMAEG notes FirstEnergy spent between $28.8–$55.4 million on vegetation management O&M expenses (OCC Ex. 16 at Attach. 1; Tr. Vol. VI at 1333). OMAEG warns that adopting the Companies' proposal would equate to collecting about $95 million each year, representing an increased spend of $47-$50 million per year (Co. Ex. 3 at 20; Co. Ex. 8 at 12; Staff Ex. 1 at 5; OMAEG Ex. 1 at 15; Kroger Ex. 1 at 10; Tr. Vol. II at 444; Tr. Vol. VI at 1333). In fact, Kroger and OMAEG observe that the additional $759.8 million the Companies seek to collect during the proposed eight-year term of ESP V represents a nearly 316 percent increase of the current baseline level (Kroger Ex. 1 at 10). Further, OCC claims Rider VMC is also unjust and unreasonable because it does not contain any proposal to pass through to consumers the apparent cost savings generated by the rider. According to OCC witness Meyer, allowing FirstEnergy to collect incremental vegetation management expenses through Rider VMC, as compared to a baseline level established in in a base rate case, would unfairly benefit FirstEnergy by reducing regulatory lag for vegetation management expenses. (OCC Ex. 1 at 16.) In addition, OCC notes that the EVM Program would generate significant cost savings as compared to FirstEnergy's normal vegetation management costs; however, none of these savings are proposed to be returned to customers (OCC Ex. 1 at 17-18; Co. Ex. 8 at Attach. STS-3). Accordingly, OMAEG, OCC, Kroger, and OELC contend that, even if

FirstEnergy required additional funds beyond those collected through base rates, FirstEnergy has failed to meet its burden to demonstrate that the amount proposed annually is not only necessary, but just and reasonable (OMAEG Ex. 1 at 18; Kroger Ex. 1 at 10-11; OCC Ex. 1 at 18-19). Alternatively, if the Commission does approve Rider VMC, Kroger and OMAEG support Staff's recommendations to reduce the recovery amounts, revisit the caps in the base rate case, shorten the recovery period to up to six years, and exclude carrying charges (Co. Ex. 9 at 2, 8; Tr. Vol. I at 178; Tr. Vol. VII at 1378-79; Staff Ex. 1 at 6, 8; Staff Ex. 5 at 4; Kroger Ex. 1 at 5.) (Staff Ex. 1 at 6.)

{¶ 173} Overall, the Companies argue that the parties opposing the EVM Program fail to acknowledge that the program will reduce the Companies' vegetation management costs, the savings of which will flow to customers through lower Rider VMC rates (Tr. Vol. XIII at 2238-39). Although Staff suggests lower annual Rider VMC caps, the Companies reiterate that the significant benefits associated with the EVM Program will not be realized if the Commission adopts Staff's proposal; however, the Companies note they would not object to Staff's reduced cap proposal if the Companies were not prohibited from seeking to implement the EVM Program and recover the associated costs elsewhere, for instance, in base rates. Relatedly, the Companies urge the Commission to deny Staff's proposal eliminate carrying charges through Rider VMC recovery, noting that such a limitation would deny them an opportunity to earn adequate compensation for the costs incurred, noting that, in the event the Companies over-recovered, customers would be credited for the associated carrying costs, as well. With respect to OCC's argument that a base rate case would enable parties to establish performance standards for the Companies' vegetation management practices, the Companies contend that the Commission's rules already require the Companies and other EDUs to develop minimum performance standards for distribution circuit performance. Ohio Adm.Code 4901:1-10-11. Additionally, the Companies note that they are required to submit annual system improvement plan reports to Staff that contain timetables and performance standards related to vegetation management, as well as other distribution system reliability data. Ohio Adm.Code 4901:1-

10-26 and -27. Further, the Companies note that they also frequently collaborate with Staff's Service Monitoring and Enforcement Department on the Companies' vegetation management plan and vegetation management cycles to ensure the Companies are on track with the established plan (Tr. Vol. XI at 2061-62). As such, the Companies argue that a rate case is unnecessary to establish or hold the Companies accountable for meeting their distribution circuit performance standards. The Companies also reiterate their earlier arguments regarding various parties' suggestions to defer ruling on the distribution rider proposals until the 2024 base rate case, noting that Rider VMC is authorized under R.C. 4928.143 and should be approved, as proposed.

{¶ 174} The Commission finds that Rider VMC should be approved, subject to the recommendations of Staff. We note the testimony of Staff witness Messenger, who testified in support of Rider VMC. Ms. Messenger stated that, based upon Staff's review of the Companies' recent historical vegetation management spending and reliability performance, the cost estimates for completing minimum regulatory work are reasonable estimates for required vegetation management spending during the term of the ESP (Staff Ex. 1 at 7). We also find the testimony of Staff witness Healey to be persuasive and relevant to this issue; Mr. Healey testified that allowing cost recovery through a rider can give the utility an added incentive to make investments that are beneficial to customers and the grid, including investment targeting reliability improvements (Staff Ex. 10 at 6). Finally, we note again that the uncontroverted testimony of Staff witness Nicodemus establishes that the interests of the Companies and their customers are aligned as provided by R.C. 4928.143(B)(2)(h) (Staff Ex. 5).

{¶ 175} Further, similar to our approval of Rider SCR, in order to ensure that refunds of Rider VMC be available to customers, we direct FirstEnergy to modify its tariff for Rider VMC to include the language "to the extent permitted by law" in the tariff language providing that Rider SCR be subject to reconciliation, including refunds, as the result of audits conducted by Staff.

{¶ 176} Staff witness Messenger also testified that any caps on the Rider VMC that are set in this proceeding should be revisited in FirstEnergy's upcoming distribution rate case to account for any change in the baseline for vegetation management spending (Staff Ex. 1 at 7). We agree with this recommendation; accordingly, we will modify the proposed ESP to set the caps for year one of the ESP at $22.1 million and for year two at $23.7 million. Caps for the remaining three years of the ESP should be established in the upcoming distribution rate case.

{¶ 177} We reject the positions advanced by OMAEG, Kroger, and OELC that Rider VMC is not required to improve reliability, as the Companies have been consistently meeting or exceeding its reliability metrics the last decade (Tr. Vol. I at 178; Tr. Vol. II at 1378-79; Co. Ex. 9 at 4-5, 8-9). The evidence in the record demonstrates that the Companies are routinely meeting their reliability standards. However, it would be short-sighted to deny the Companies are valuable tool to maintain or improve reliability simply because the Companies have, thus far, met their reliability standards, particularly when the record is clear that vegetation management costs have significantly increased (Co. Ex. 8 at 11-12).

M. Rider ELR

{¶ 178} The Companies propose to continue their current Rider ELR program, subject to several modifications intended to improve the efficiency and affordability of the program. According to the Companies, Rider ELR is a tariff-based interruptible program designed to support demand response and economic development throughout the Companies' service territories, which was originally authorized in ESP I and continued, with modification, in subsequent ESPs. *ESP I Case*, Second Opinion and Order (Mar. 25, 2009); *ESP II Case*, Opinion and Order (Aug. 25, 2010) at 37; *ESP III Case*, Opinion and Order (July 18, 2012) at 37; *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 94. FirstEnergy witness McMillen explained in his testimony that customers participating in Rider ELR commit their curtailable load to the Companies and are then subject to emergency curtailment events called by either the Companies or PJM. As an incentive, Rider ELR participants currently have the opportunity to earn credits of ten dollars per kW of curtailable load per month.[27] Additionally, Rider ELR participants cannot participate in any other load curtailment or demand response program, including those offered by PJM. (Co. Ex. 3 at 11.) For ESP V, the Companies propose to continue Rider ELR, subject to two primary modifications. First, the Companies will no longer require Rider ELR customers to commit their demand response capabilities to the Companies, instead requiring them to participate in PJM demand response programs through a curtailment service provider (CSP) of their choice. Second, through the ESP V term, the Companies propose reductions in the Rider ELR credits, in which the credits would be reduced to $5.00 in the first year, and would be reduced by $0.50 every year thereafter for the duration of ESP V, equating to $1.50 beginning on June 1, 2031, the last year of proposed ESP V. (Co. Ex. 3 at 12.) Additionally, the Companies propose modifications to the Rider ELR tariff to: (1) remove provisions related to emergency curtailment events called by PJM, and (2) revise the penalty tariff provision to be consistent with the Commission’s directive in another case (Co. Ex. 3 at 14-15). According to the Companies, its proposed modifications will not diminish Rider ELR's potential to provide its noted benefits; rather, FirstEnergy opines that its Rider ELR proposals appropriately balance support for valuable demand response and economic development with rate impacts to participating and non-participating customers.

{¶ 179} FirstEnergy, OEG, OELC, and Nucor also profess the numerous benefits derived from the ELR program, specifically those related to increased reliability and economic development. As Nucor Witness Dr. Goins testified, “[a]lthough Rider ELR has undergone modifications in earlier ESP cases, the credit and the rate’s other core elements have been in place since FirstEnergy’s first ESP was approved, resulting in a stable, long-

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27 As noted by the Companies, this $10 per kW incentive credit is earned under two separate provisions: (1) five dollars per kW of curtailable load per month under Rider ELR, recovered through the Companies’ Demand Side Management and Energy Efficiency Rider (Rider DSE1); and (2) five dollars per kW of curtailable load per month of the Companies Economic Development Rider (Rider EDR) provision (b), recovered via Rider EDR(e) (referred to collectively as Rider ELR credits).

term, and reliable source of interruptible capacity for the FirstEnergy utilities for well over a decade." (Nucor Ex. 1 at 7). OEG and OELC emphasize the importance of the ELR program during Winter Storm Elliott, where interruptible customers were curtailed for long durations on December 23, 2022 and December 24, 2022, in order to avoid rolling blackouts (OEG Ex. 3 at 6; OELC Ex. 32 at 47-48). During the December 24, 2022 event, OEG notes that all 24 business participating in Rider ELR were asked to curtail their load for 236 hours, or 9.8 hours per customer, adding that all 24 business were able to do so (OELC Ex. 32 at 44-46). Further, as a result of those critical curtailments, OEG, and Nucor note that FirstEnergy received approximately $11.4 million in payments from PJM, a portion of which flowed back to customers. As such, OEG, OELC, and Nucor argue that the ability to curtail load in emergency events where there exists the possibility that demand could exceed supply in PJM remains a critical tool to protect the reliability of the distribution system. (OELC EX. 32 at 44-45; Nucor Ex. 1 at 7-9.) OEG, OELC, and Nucor add that these interruptible resources have become even more critical recently in the midst of the accelerated retirement of dispatchable generation and legacy resources, noting reliability concerns stemmed from changes to the generation resource mix and forecasted load growth (OEG Ex. 3 at 7; OELC Ex. 32 at 51; Nucor Ex. 1 at 8). For instance, OEG notes that, as of April 30, 2023, PJM's interconnection queue had 183,279 MW of generation projects awaiting approval for interconnection, comprised of the following: 53,871 MW of storage projects, 74,300 MW of solar projects, 18,945 MW of wind projects, 30,016 MW of hybrid projects, 5,518 MW of natural gas projects, and the remaining 629 MW of "other projects." OEG points out that almost 97 percent of the projects in PJM's interconnection queue are associated with renewable energy facilities. (OEG Ex. 3 at 8-9.) OEG argues that FERC, the North American Reliability Corporation, the U.S. Environmental Protection Agency, and the U.S. Department of Energy have all emphasized the need to maintain the reliability of the power grid as dispatchable thermal generation is retired in favor of the intermittent renewable generation (OEG Ex. 3 at 8, 10, 12). OEG adds that both the Commission and Staff have also expressed this noted concern, emphasizing the importance of maintaining existing resources at the state level to support the reliability of the grid, such as interruptible rate programs (OEG Ex. 3 at 11-12, Attach. KMM-8). OEG claims that states, through interruptible programs, have the ability to protect reliability of the grid by establishing resources in furtherance of that objective, beyond the scope of protection that can be offered by PJM (OEG Ex. 3 at 14-15; OELC Ex. 32 at 48). Moreover, OEG asserts that there are several obstacles for PJM programs to provide enough incentive to effectively mitigate the current reliability concerns, including the recent trend of lower capacity prices that may dissuade large industrial manufacturers to curtail their operations, and the risk of higher capacity performance penalties that could discourage large energy users from participating (OEG Ex. 3 at 15; OELC Ex. 32 at 48). In fact, OEG notes this is not speculation, as there has been a decline in participation in PJM demand response programs over recent years (OEG Ex. 3 at 15-16). OEG claims that the preservation of retail interruptible load programs will allow the Commission to design programs that encourage Ohio's large energy users to promote grid reliability.

{¶ 180} OEG and Nucor also maintain that the Companies' interruptible rate program promotes economic development within Ohio by helping ensure that Ohio's electric rates are competitive and by encouraging capital investment within the state. Noting that electric energy is a major operating cost for large, energy-intensive industrial customers, Nucor witness Goins noted that "low, stable electricity prices are vital for their continued operation in Ohio" adding that "Rider ELR helps such customers lower their electricity costs if they are willing to accept lower-quality curtailable service." (Nucor Ex. 1 at 9). OEG asserts FirstEnergy's interruptible rate program also helps maintain the competitiveness of Ohio's electric rates as compared to the rates available in other states, specifically citing comparable interruptible programs in Indiana and Kentucky (OEG Ex. 3 at 16). By continuing interruptible rate programs in Ohio, OEG claims that the Commission will help maintain the state's economic competitiveness both locally and globally, as large, energy-intensive customers search for competitive advantages, including competitive electric power pricing.

1. CSP of Customer's Choice

{¶ 181} As to the Companies' first proposed modification, the Companies assert that the transition away from their current role as the CSP for ELR customers will improve Rider ELR's administrative efficiency and enable Rider ELR participants to directly engage in multiple PJM demand response programs, which opportunities are not currently available. FirstEnergy claims this change will promote customer choice, enabling Rider ELR customers to participate in programs based on their individual needs and preferences, and allow them to use a single CSP for all their market activities. (Co. Ex. 10 at 5.) Moreover, FirstEnergy asserts that the transition will allow Rider ELR customers the freedom to contract with independent CSPs and provide them with the opportunity to receive additional revenues. Currently, as the Companies currently act as the CSP, any revenues from bidding Rider ELR resources into PJM capacity auctions is split between customers, at 80 percent, and the Companies, at 20 percent. Once the Companies are no longer the CSP for Rider ELR customers, the Companies will no longer be responsible for offering Rider ELR resources into PJM capacity auctions, and therefore, will not receive any PJM revenues. (Co. Ex. 10 at 5-6.) Instead, the Companies note that Rider ELR customers will have the ability to work with their own CSPs to decide how any PJM revenues will be distributed.

{¶ 182} Staff supports the Companies' proposal to no longer serve as the CSP for the ELR program, as it would promote a more market-based approach by allowing large nonresidential customers to participate in demand response programs on their own and potentially keep any PJM revenues resulting from their participation. However, Staff suggests that FirstEnergy continue to operate as the CSP through the first year of the ESP. (Co. Ex. 10 at 4-5; Staff Ex. 10 at 21.)

{¶ 183} OEG and OELC contend that the Companies' proposal to make it mandatory that all ELR customers must participate in PJM demand response through a third-party CSP should be rejected. Instead, posits OEG and OELC, ELR customers should have the option, but not the obligation, to bid their load into PJM as a means of mitigating any reduction in the ELR credits (OEG Ex. 3 at 19). OEG and OELC argue that FirstEnergy's mandatory approach is flawed as compared to the current practice since it could lessen the reliability protections provided by the program, emphasizing that FirstEnergy's proposal would not require that the amount bid into PJM through a third-party CSP match the amount of contractual interruptible load offered by the customer under Rider ELR (Tr. Vol. VII at 1388; Tr. Vol. XIV at 2522-23). Moreover, OEG contends it is unreasonable for FirstEnergy to mandate wholesale market participation as a condition to participate in a state rate mechanism, as it would subject participants to both state penalties and PJM penalties for failure to curtail. OEG and Nucor further argue that this mandatory approach would also force businesses seeking to participate in Rider ELR to either become a CSP or to incur additional costs in order to register with a third-party CSP, which not all Rider ELR customers may be interested in doing (Nucor Ex. 1 at 4). OEG and OELC also emphasize that an optional approach is also currently used in AEP Ohio's Interruptible Power Rider – Expanded (IRP-E) program and may have the effect of producing low peak load contributions (PLC) values (Tr. Vol. XIV at 2531). Importantly, OEG and OELC note that providing the option to participate in PJM does not result in additional direct costs to other FirstEnergy customers, with, at most, being the additional burden of FirstEnergy to maintain its own interruption communication system with ELR participants in order to issue interruption notices for localized or distribution system emergencies that may occur separate and apart from any PJM notices. Regardless, OELC contends that FirstEnergy has not provided a realistic timeframe to permit Rider ELR participants to enroll their curtailable load with a CSP for the June 1, 2024 through May 31, 2025 delivery year (OELC Ex. 32 at 54-55). OELC agrees with Staff that FirstEnergy should continue to serve as the CSP through at least May 31, 2025, in order to give Rider ELR customers necessary time to retain a third-party CSP and have their load registered in sufficient time to participate in the PJM capacity auctions, which typically falls within the month of January preceding the June-May delivery year (OELC Ex. 32 at 54-55).

{¶ 184} Nucor contrarily advocates for the status quo, arguing that FirstEnergy should continue to serve as the CSP for the Rider ELR load for purposes of participation in the PJM capacity markets, as it has done since the program's inception. Nucor explains that having FirstEnergy serve as the single point of contact for ELR interruptions, regardless if the event is initiated by PJM or one of the Companies, remains the simplest approach to managing the Rider ELR interruptible load. Further, revenues FirstEnergy receives as a result of bidding the ELR load into the capacity market should continue to be passed back to FirstEnergy's customers to offset the cost of the ELR credits, especially when capacity prices are likely to increase (Co. Ex. 3 at 14). Acknowledging that these revenues can be quite sizable, Nucor states that, over the course of ESP IV, FirstEnergy credited to customers approximately $17.4 million for capacity payments resulting from Rider ELR load enrollment in PJM (OMAEG Ex. 12; Co. Ex. 3 at 14). Nucor argues that FirstEnergy has failed to provide any circumstances that would prevent it from retaining its role as the CSP and, in fact, conceded there would be no reason why the Companies cannot continue to serve as CSP if the Commission directed the Companies to do so. (OELC Ex. 1; Tr. Vol. II at 298.) Nucor also questions FirstEnergy's proposal when it plans to perform these same CSP functions for selected energy efficiency programs, if approved (Co. Ex. 5 at 30). Finally, Nucor raises concerns that FirstEnergy's proposal may result in a system where customers would need to monitor curtailment notices from their CSP for PJM emergencies as well as from their utilities for local emergencies, leading to customer confusion regarding notice priority and increase the risk of customers missing such notices altogether (Nucor Ex. 1 at 17; Tr. Vol. III at 523; Tr. Vol. VII at 1526). As such, Nucor alleges the better approach is to have FirstEnergy continue in its role as the CSP. Although Nucor supports retaining FirstEnergy as the CSP, if the Commission approves FirstEnergy's proposal, Nucor agrees with OELC's witness Brakey's recommendation to delay the transition for at least a year after the start of ESP V (OELC Ex. 32 at 54-55). Nucor also notes that Staff witness Healey acknowledged OELC's proposal was reasonable in light of concerns about Rider ELR customers' ability to transition to their own CSPs in time for 2024 (Staff Ex. 10 at 21-22).

{¶ 185} OCC quickly observes that by eliminating FirstEnergy's role as the CSP, FirstEnergy will no longer earn capacity market revenues to help offset the cost of Rider ELR, thus eliminating a prior justification for having the interruptible tariff in the first place (OELC Ex. at 39).

2. Rider ELR Credit Amounts

{¶ 186} Recognizing that Rider ELR credits are currently much higher than PJM market capacity prices, the Companies assert that the proposed reductions in Rider ELR credits will better align the program's costs with market pricing while still supporting economic development and demand response within the Companies' territories (Co. Ex. 3 at 13; Co. Ex. 10 at 6-7). FirstEnergy also asserts the proposed reductions will mitigate rate shock to both participating and non-participating customers by (1) delaying credit reductions until the second year of ESP V, (2) reducing credits in a gradual manner, and (3) reducing costs to non-participating customers (Co. Ex. 3 at 13).

{¶ 187} While broadly agreeing with the reliability and economic development benefits associated with the ELR program, Staff argues that a quantitative and qualitative analysis is necessary to determine an appropriate credit amount for program participants. Staff began such an analysis by evaluating market pricing, determining that PJM demand response clearing prices over the last decade averaged around $3.40/kW-month. According to Staff, continuing the existing $10/kW-month credit, which is nearly three times the average market price, would result in undue subsidies paid by nonparticipating customers. (Staff Ex. 10 at 24.) Furthermore, Staff notes that its proposal to reduce the credit by half in the first year of ESP V should be taken with a holistic view of the program. Staff's proposal incorporates the Companies' suggestion that ELR participants would engage their own CSP, and, thus, would be able to keep any PJM revenues to ease the difference caused by the decreased credit amount (Staff Ex. 10 at 21-24; Tr. Vol. VIII at 1680). Taking these two suggestions together, Staff argues its proposal is consistent with the principle of gradualism and mitigates concerns about rate shock for ELR participants (Staff Ex. 10 at 25; Tr. Vol. XIV at 2538). Further, Staff argues that the noted benefits of the program discussed above come at a cost in the form of rider charges for nonparticipating customers, noting that a balanced approach should seek to maximize participation in the program while minimizing costs paid by nonparticipants (Staff Ex. 10 at 26). Staff does not anticipate lowering the credits to the suggested amounts will result in lower participation in the program, citing high participation in AEP Ohio's program despite offering credits for less than a dollar in recent years (Tr. Vol. XIV at 2588). According to Staff, its proposed credits will offer the same reliability benefits currently provided by the ELR program, but at a lower cost. Further, Staff notes that many of the intervenor proposals do not offer the same quantitative justification for their credit amounts; however, Staff also readily admits that this quantification is difficult to ascertain with precision and that the Commission will have to determine the appropriate level of the ELR credit by balancing the value of the program with the associated costs to both participating and nonparticipating customers.

{¶ 188} OEG recognizes that there may be some dispute as to the credit amount, but notes that it, FirstEnergy, OELC, and Nucor unanimously recommend that the interruptible credit be maintained at its current level through at least the first year of the proposed ESP (Co. Ex. 3 at 12; OEG Ex. 3 at 3; OELC Ex. 32 at 46; Nucor Ex. 1 at 16). Further, OEG states that, despite Staff's focus on the current $60 million cost of the program, the cost is spread over the entire distribution system, resulting in a cost to the average residential customer of about 25 cents per month (Tr. Vol. III at 543). In fact, OEG and Nucor contend that Staff's recommended 50 percent cut in the first year of the ESP may consequently lead to rate shock for businesses currently participating in the ELR program, contrary to its objective to foster gradualism in resulting rates (Staff Ex. 9 at 6-7, 11-12; Staff Ex. 10 at 6-7). OEG also contends that FirstEnergy's ELR program is distinct from PJM's wholesale demand response programs. For instance, FirstEnergy's program subjects participating customers to curtailments at any time and for any duration, whereas curtailments in the PJM program are limited to certain periods (OELC Ex. 32 at 40; Tr. Vol. XIV at 2526). Additionally, OEG claims that FirstEnergy's current ELR program also requires participating customers to curtail for both PJM regional events and local distribution emergencies, thus, providing more expansive reliability protection than what is otherwise available by PJM, as well as the noted economic development benefits. OEG claims the notable differences between the two programs justify a credit higher than PJM demand response clearing prices (Staff Ex. 10 at 24). As such, balancing all of the above considerations, OEG proposes a lessened reduction of the credits as compared to Staff, with payments at the current $10 in the first year and then decreasing by one dollar per year until they reach seven dollars, where they would remain for the duration of ESP V (OEG Ex. 3 at 17-18).

{¶ 189} OELC and Nucor, emphasizing the benefits derived from the ELR program, suggest that the Commission maintain the current $10/kW-month credit for the entirety of ESP V (OELC Ex. 32 at 46; Nucor Ex. 1 at 11). Once again noting the reliability concerns resulting from the trend of non-dispatchable generation resources replacing legacy generation, increased retirements of baseload generation, and projected load growth in the PJM footprint, OELC and Nucor contend that FirstEnergy's interruptible program will play an increasingly critical role in safeguarding PJM grid reliability, the footprint of which includes FirstEnergy's customers, during the term of ESP V. (OELC Ex. 32 at 46-47, 51; Nucor Ex. 1 at 13-14). Accordingly, OELC and Nucor assert it is "short-sighted over an eight-year ESP V to drastically reduce the Rider ELR program credits based on the current, likely transient, dip in capacity prices in current years," further claiming adopting the Companies' proposal to reduce the credits will undermine the incentives available for Rider ELR participants to remain in the ELR program (OELC Ex. 32 at 47, 49-51; Nucor Ex. 1 at 12-13; OCC Ex. 2 at 9; Tr. Vol. VII at 1463-64). OELC and Nucor further contend that the Companies' proposed credit reduction also fails to take into consideration the economic development benefits noted above (Tr. Vol. III at 548). OELC notes various public comments submitted in this proceeding from ELR program participants, in which the participants tout these economic development benefits and note the importance of the existing level of credits afforded by the program. (Comment Letter from Roger Koeberle (Dec. 5, 2023)); (Comment Letter from Comment letter from Skip Slaven (Dec. 5, 2023)); and (Comment letter from

Nathan Jacobs (Dec. 7, 2023)). Accordingly, OELC also contends that the evidence and record demonstrate that FirstEnergy's proposed reduction of the Rider ELR Program credits would undermine the economic development benefits of the program. However, if the Commission decides that the monthly Rider ELR credit must be reduced, Nucor suggests that the Commission should adopt a lessened and more gradual reduction in the credit, adding that it should be no less than $8/kW over the term of the ESP. Further, Nucor recommends that the aggregate credit for each delivery year should remain at least equal to 80 percent of the capacity auction clearing price for the relevant delivery year. (Nucor Ex. 1 at 16.) Nucor claims that a stable and robust Rider ELR credit is necessary to retain Rider ELR customers over the term of the ESP, noting FirstEnergy did not engage in any analysis as to what level of credit reduction may cause Rider ELR customers to leave the program (Nucor Ex. 1 at 14-15; Tr. Vol. III at 548). Relatedly, Nucor contends that FirstEnergy also did not quantify the amount of potential PJM revenues from participating in the capacity market that could offset any reduction in the Rider ELR credits, which could be quite volatile (Tr. Vol. II at 351; Tr. Vol. III at 546). As they claim the record demonstrates the importance of retaining interruptible load on the grid, Nucor and OELC argue that the credits should not be reduced.

{¶ 190} Given the many recommendations raised by parties in this proceeding, OEG and OELC also developed an alternative recommendation that seeks to harmonize their original positions, which proposes, among other things, to reduce the interruptible credit to $9/kW-month in the first year, to $8/kW-month in the second year, and to $7/kW-month in the fourth year.

3. Size of the ELR Program

{¶ 191} Relatedly, Staff also suggests that a balancing of competing interests is necessary to determine the proper size of the ELR program. While Staff generally supports competition and open access to participation in utility programs, it is also cognizant that caps on participation will mitigate bill impacts for nonparticipating customers. To balance these interests, Staff recommends that the ELR program be increased by 50MW each year for five years, beginning June 1, 2025, amounting to an additional 250MW available to new participants. (Staff Ex. 10 at 26.) Under Staff's proposal, the 50MW would be open to new participants first, with the same per-kW credit amounts and requirements as current participants. However, if new participants do not fill the entire 50MW after a reasonable period, Staff suggests that current ELR participants could then be offered to increase their interruptible load (Staff Ex. 10 at 27). Notably, Staff claims that, if its proposed credit amounts are adopted by the Commission, nonparticipants will pay less under Rider ELR than they do currently, even with the additional 50MW of participation (Staff Ex. 10 at 17, 27). Staff urges the Commission to adopt its proposal, as it allows additional customers to participate in the ELR program while considering nonparticipant rate impacts.

{¶ 192} OELC recommends unlimited participation in the program with no cap on charges to nonparticipants (Tr. Vol. IX at 1776). OMAEG agrees that any approved ELR program should be expanded, specifically noting that the program should "be available to any commercial or industrial [C&I] customer that can interrupt its load," but does not necessarily agree with OELC that no caps should be imposed (OMAEG Ex. 1 at 4; OELC Ex. 32 at 54; Tr. Vol. VIII at 1656; Tr. Vol. XII at 2118, 2132). OEG also supports expanding the program, especially given the need for reliability resources due to the accelerated retirement of dispatchable generation (OELC Ex. 32 at 54; Staff Ex. 10 at 26).

4. ADDITIONAL RECOMMENDATIONS FOR RIDER ELR

{¶ 193} The Companies currently recover the costs of the program through two different riders, Rider DSE1 and Rider EDR. To simplify cost recovery, Staff recommends that all ELR program costs be recovered through Rider EDR by shifting what was previously recovered through Rider DSE1 as a new component of Rider EDR, with the same allocation currently being used under Rider DSE1. The allocations and calculation of per kWh rates for Rider EDR(e)-1 and Rider EDR(e)-2 should continue without modification. Then, all three per-kWh rates should be included in the overall Rider EDR rate. Staff also notes this proposal would allow Rider DSE to be removed from the Companies' tariffs once there is a final reconciliation of Rider DSE2. (Staff Ex. 10 at 19-20.) OEG supports Staff's position to move the costs associated with the ELR program to Rider EDR.

{¶ 194} In addition to the noted recommendations discussed above, OEG makes several other suggestions for the ELR program for the Commission's consideration. First, OEG contends that the program should maintain the current requirement for curtailments for distribution and transmission emergency events, instead of limiting it to distribution events (Tr. Vol. XIV at 2523-26). OEG once again raises AEP Ohio's interruptible rate program as a quick comparison, noting that program allows the utility to interrupt for both transmission and distribution emergencies. Next, under FirstEnergy's proposed program, a customer that fails to curtail during an emergency event is subject to several penalties set forth in the Rider ELR tariff, including an emergency curtailment event (ECE) charge. Both OEG and OELC contend that, depending on the market conditions at the time of the event, the charge is calculated at 300 percent times the PJM Locational Marginal Price at the appropriate pricing node during the applicable hour(s) of the emergency event (OELC Ex. 32 at 40; Tr. Vol. II at 333-336; Tr. Vol. XIV at 2527-28). As such, OEG and OELC suggest that the penalty for non-compliance should be modified to eliminate the ECE charge (OEG Ex. 3 at 19). OELC adds that the Companies have failed to produce any justification for modifying the current penalty structure, which is already quite stringent, and there is no evidence of any Rider ELR participant failing to curtail their interruptible load when called upon by FirstEnergy. OEG also recommends that participating customers have the ability to change their firm service level annually, which it notes was unopposed during the hearing. Importantly, OEG contends that this component of its proposal will not result in additional ELR load or added costs to other customers; instead, it will provide flexibility to participating customers by allowing them to revise their firm service levels in response to prevailing business conditions and their specific operating expectations for the year. (OEG Ex. 3 at 18.) Moreover, OEG notes that this approach would be consistent with that outlined in the AEP Ohio settlement. *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at 30-

33. Finally, although annual testing can be somewhat burdensome for ELR customers, OEG argues it remains an important component to the program as it helps ensure that the promised reliability benefits materialize in an emergency event and, as such, requests that it be maintained (OEG Ex. 3 at 19).

{¶ 195} While acknowledging various benefits that may be derived from interruptible programs, as suggested by the other parties, OMAEG states that neither FirstEnergy's current nor proposed ELR programs are designed to effectively improve reliability or allow participants to become more economically competitive (OMAEG Ex. 1 at 8-9). Instead, posits OMAEG, the program, as designed, is "duplicative of a competitive market service and is anticompetitive" (OMAEG Ex. 1 at 6, 12; Tr. Vol. XII at 2122, 2134). OMAEG recommends modifying the ELR program to couple load curtailment with transmission and distribution system reliability needs, noting the lack of demand response and load shedding for transmission system issues (OMAEG Ex. 1 at 5-12; Tr. Vol. XII at 2122-23). OMAEG witness Seryak specifically recommends that the ELR program be modified to remove the PJM demand response component, and instead become a program that responds to curtailable events based on transmission facility overloading (OMAEG Ex. 1 at 21; Tr. Vol. XII at 2119, 2122-23, 2134).

{¶ 196} However, if the Commission does not modify the ELR program as suggested by OMAEG witness Seryak, OMAEG argues that the program should be eliminated because it is duplicative, anti-competitive, and inherently discriminatory (OMAEG Ex. 1 at 6, 12). OCC and NOAC join OMAEG on these particular arguments. OMAEG, NOAC, and OCC highlight the fact that, under the Companies' proposal, the 24 existing customers currently participating in the ELR program will be the only participants eligible to participate in ESP V through May 31, 2032, and new and/or existing customers able and willing to interrupt their load will be prohibited from participating (OMAEG Ex. 12; Co. Ex. 3 at 12; Staff Ex. 8 at 25-26; Tr. Vol. II at 327, 439-41; Tr. Vol. VII at 1576; Tr. Vol. VIII at 1658). OCC and OMAEG also contend this proposal contradicts the stated goal of using the program to support demand response and economic development, as expanding participation in the program would allow for these alleged benefits to be maximized (Co. Ex. 2 at 7; Co. Ex. 3 at 13; Co. Ex. 10 at 5). Given the limitations on participation, OCC alleges the ELR program "violates" several aspects of the state's energy policy regarding the provision of reasonably priced electric service, adequate consumer protections, and effective competition through the avoidance of anticompetitive subsidies. *See* R.C. 4928.02(A), (H), (I), (L), and (N). Additionally, OCC and OMAEG allege the ELR program, as proposed, is also unreasonably costly to non-participating customers, noting that current credits greatly exceed capacity prices. Further, even with FirstEnergy's proposed credit reduction, OMAEG contends that the 24 participating customers will still be earning far more through the ELR program than they would through a comparable PJM interruptible program. (Tr. Vol. VII at 1507; OMAEG Ex. 1 at 8; Co. Ex. 10 at 6-7.)

{¶ 197} OCC and OMAEG also allege that the ELR program is not utilized enough to reduce load in the system or provide other benefits to justify these costs, claiming that, since 2009, ELR participants have only had to interrupt their load usage four times in response to load shed calls made by PJM (Tr. Vol. VIII at 1666; Co. Ex. 3 at 12; Co. Ex. 10 at 6). Notably, OCC adds that FirstEnergy never actually interrupted service during the entire term of ESP IV, except once per year to comply with PJM's testing requirements (Tr. Vol. VII at 1495). Further, OCC points to FirstEnergy witness Stein's testimony where he explained that the Companies, as members of PJM, must follow PJM's Reliability Assurance Agreement, which charges PJM as the entity to provide instructions to individual utilities on how to respond to an emergency event, such as curtailing load (OCC Ex. 13 at Section 9.1). According to OCC and NOAC, the infrequency of FirstEnergy-initiated curtailments does not justify the amount paid to these 24 customers, which was approximately $437,415,854 during the last seven years of ESP IV (Staff Ex. 10 at 17). Furthermore, OMAEG contends that demand response programs already exist in the competitive market and that the ELR program, as currently designed, does not offer any unique attributes that would distinguish from those already-available programs (Tr. Vol. XII at 2122; OMAEG Ex. 1 at 6). If the Companies' proposal to discontinue its role as the CSP is adopted, OMAEG notes that the ELR program becomes even more unnecessary, as ELR participants will then be able to participate in PJM interruptible programs on their own (Co. Ex. 10 at 4-5; Staff Ex. 8 at 19-20). Notably, OCC and NOAC emphasize that Duke and AES Ohio do not have interruptible service programs, despite also belonging to PJM, and further argues that eliminating the ELR program will align FirstEnergy more closely with these similarly-situated EDUs and avoid undue discrimination between their customers[28] (Staff Ex. 10 at 17; Tr. Vol. VII at 1472; Tr. Vol. XIV at 2543-47).

5. Commission Conclusion

{¶ 198} As argued by FirstEnergy, OEG, Staff, OELC, and Nucor, the Commission has previously found that the Rider ELR Program provides economic and energy efficiency benefits to customers and in this way "should facilitate the state's effectiveness in the global economy in accordance with R.C 4928.02(N)." *ESP IV Case*, Opinion and Order (March 31, 2016) at 94, citing *ESP I Case*, Opinion and Order (Mar. 25, 2009) at 10. The Commission has also expressly held that FirstEnergy's "interruptible load programs provide reliability, economic and energy efficiency benefits to customers," and that all customer classes benefit from the program. *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 94; *ESP III Case*, Opinion and Order (July 18, 2012) at 37. We witnessed how important this vital program can be when interruptible customers were curtailed to avoid rolling blackouts during Winter Storm Elliott (OEG Ex. 3 at 6; OELC Ex. 32 at 47-48). While OCC, OMAEG, and NOAC contend the program is not utilized enough to warrant continuation, i.e., there are not enough interruptions, we note the true value of the ELR program is derived from the availability of interruptible load (Staff Ex. 10 at 16; Nucor Ex. 1 at 7-9; OELC Ex. 32 at 44-45). As such, we continue to find that the ELR program serves an important role in promoting

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[28] OCC notes that Staff witness Healey's testimony demonstrates that these three utilities are similarly situated as to their ability to provide reliable distribution service, assuming the Commission approves FirstEnergy's request to implement Rider SCR and Rider VMC (Tr. XIV at 2547). As such, in the event those riders are approved, OCC suggests that the ELR program be eliminated.

grid reliability (OEG Ex. 3 at 7, 10-12; OELC Ex. 32 at 48, 51; Nucor Ex. 1 at 8). It is also not determinative that AES Ohio and Duke do not currently have such a program. As noted by Staff witness Healey, "[t]here may be some utilities where having an interruptible tariff is the best way to maintain that system amongst all the various other things that they do to maintain reliability, whereas, there may be others where they can do it without it." (Tr. XIV at 2546-47). In fact, the Commission has regularly approved such programs for multiple EDUs and determined that they provide flexible options for energy intensive customers, as most recently seen in AEP Ohio's fifth ESP. *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at ¶¶109, 144; *see also In re the Application of Columbus S. Power Co. and Ohio Power Co.*, Case Nos. 11-346-EL-SSO, et al., Opinion and Order (Aug. 8, 2012) at 26; *AEP Ohio ESP IV Case*, Opinion and Order (Apr. 25, 2018) at ¶ 140; *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 14, 26, 70-71; *Duke ESP III Case*, Opinion and Order (Apr. 2, 2015) at 78; *ESP III Case*, Opinion and Order (July 18, 2012) at 8, 11, 56; *In re Duke Energy Ohio, Inc.*, Case No. 11-3549-EL-SSO, et al., Opinion and Order (Nov. 22, 2011) at 36; *ESP II Case*, Opinion and Order (Aug. 25, 2010) at 36. OMAEG witness Seryak claims that the ELR program is duplicative and unnecessary, given the programs offered by PJM; however, as noted by OEG, there may be certain limitations in place for PJM to incentivize participants, such as lower capacity prices, that dissuade large energy users from participating, evidenced by declining participation in PJM demand response programs over recent years (OEG Ex. 3 at 14-16; OELC Ex. 32 at 48). Moreover, Staff adds that the ELR program allows FirstEnergy to call curtailment events on its own to respond to localized threats to the grid, in addition to those called by PJM (OELC Ex. 32 at 40; Tr. Vol. XIV at 2526). Thus, we disagree that the significant modifications to the ELR program, as suggested by OMAEG witness Seryak, are necessary at this time (OMAEG Ex. 1 at 21; Tr. Vol. XII at 2119, 2122-23, 2134). Additionally, we agree with OEG and Nucor and continue to find that the ELR program promotes economic development within Ohio by helping ensure that the state's electric rates are competitive and by encouraging capital investment, which PJM's demand response programs are simply not designed to do (Nucor Ex. 1 at 9; OEG Ex. 3 at 16). As we have determined in previous rulings on interruptible programs, the terms of the ELR program outlined in the

Application, as modified herein, will continue to further numerous state policies encapsulated in R.C. 4928.02, such as encouraging demand-side management and facilitating the state's effectiveness in the global economy, as well as promote grid reliability in Ohio. *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 94; *ESP III Case*, Opinion and Order (July 18, 2012) at 37; *ESP II Case*, Opinion and Order (Aug. 25, 2010) at 36; *ESP I Case*, Opinion and Order (Mar. 25, 2009) at 10.

{¶ 199} Recognizing these significant benefits are still present today, now the Commission turns to what, if any, modifications are necessary to the existing ELR program, as suggested by FirstEnergy and other parties to this proceeding. As Staff, FirstEnergy, Nucor, and OEG have noted, while many proposals have been suggested, the Commission will need to balance the interests of those involved in order to maximize participation in the program while minimizing costs paid by nonparticipants (Staff Ex. 10 at 26). It is in this context where we will evaluate the proposals' effect on the notable benefits the ELR program has historically provided with the rate impacts to participating and non-participating customers.

{¶ 200} First, as to FirstEnergy's proposal to no longer serve as the CSP, we agree that allowing large, non-residential customers to participate in demand response on their own and potentially keep any PJM revenues resulting from their participation reflects a more market-based approach (Co. Ex. 10 at 4-5; Staff Ex. 10 at 21). Currently, as the Companies act as the CSP, any revenues from bidding Rider ELR resources into PJM capacity auctions are split between customers, at 80 percent, and the Companies, at 20 percent. Once the Companies are no longer the CSP for Rider ELR customers, the Companies will no longer be responsible for offering Rider ELR resources into PJM capacity auctions and, therefore, will not receive any PJM revenues. (Co. Ex. 10 at 5-6.) According to the Companies, not only will this transition bolster customer choice by allowing customers to participate in programs based on their individual needs, it will also improve Rider ELR's administrative efficiency (Co. Ex. 10 at 5). We note that OEG and OELC advocate for an optional approach for participation in PJM demand response, raising AEP

Ohio's IRP-E program as an example of a currently authorized interruptible program that provides customers the option, but not obligation, to bid their load into PJM as a means of mitigating any reduction in the ELR credits (OEG Ex. 3 at 19; Tr. Vol. XIV at 2531). *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at 30-33. We agree that participants in FirstEnergy's ELR program should be afforded the same opportunity and direct that ELR participants should have the option, but not the obligation, to participate in PJM. We find that, once a customer elects to obtain its own CSP, this choice should be irrevocable for the term of this ESP and that, in exchange for the customer retaining any PJM revenues, there should be a $2/kW-month reduction in the otherwise applicable credit for participation in the ELR. For those who continue to have FirstEnergy serve as the CSP, we direct that the revenues resulting from bidding ELR resources into PJM capacity auctions continue to be split between customers, at 80 percent, and the Companies, at 20 percent. Further, we agree that ELR participants should have the ability to reset their firm service levels annually, beginning on May 31, 2024, and on May 31st of each subsequent year of the ESP, similar to participants in AEP Ohio's IRP-E and IRP-L programs. *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at 30. This annual reevaluation will be important to accommodate potential changes to operations or load growth over the course of the ESP V term. However, we agree an alternative method for establishing a firm service level will need to be established for those who choose to have FirstEnergy continue to operate as the CSP. While this may admittedly increase the administrative burden associated with the program, we recognize that burden is outweighed by the value associated with the ability of customers to choose who serves as their CSP. Further, as discussed above, there is already a comparable program that allows for such annual reevaluation. FirstEnergy and Staff are directed to collaborate to identify an appropriate notice mechanism for interested participants to annually reset their firm service levels, without changing their interruptible load subscription under the ELR program. Additionally, allowing ELR participants to participate at PJM also addresses OEG's recommendation that ELR participants be subject to annual performance testing because it appears PJM will already require such testing for those who choose to participate. However, if PJM does not perform such a test, we agree with OEG and OELC that annual testing is important to maintain and direct FirstEnergy to call at least one test event per year for the duration of ESP V for both those that choose to participate in PJM and for those which FirstEnergy remains the CSP.[29] As discussed above, the Commission has evaluated all proposals in order to balance the impacts on both participating and non-participating customers, as suggested by the parties. The ELR program, at its core, is a voluntary program in which customers may elect to participate in if it is in their best interest to do so. Customers will need to evaluate several factors to determine if this is the case, including the ability to retain PJM revenues, as well as the amount of the credits available, as discussed below. We agree allowing this more market-based approach is appropriate and find that the Companies' proposal should be adopted as modified herein. However, we are concerned with the timeframe proposed to allow Rider ELR participants to enroll their curtailable load with a CSP for the June 1, 2024 through May 31, 2025 delivery year (OELC Ex. 32 at 54-55). As such, we will also adopt Staff's suggestion, as supported by OELC and OEG, and direct that FirstEnergy continue to serve as the CSP through May 31, 2025, in order to give Rider ELR customers necessary time to retain a third-party CSP and have their load registered in sufficient time to participate in the PJM capacity auctions (OELC Ex. 32 at 54-55; Staff Ex. 10 at 21-22). As noted by Nucor, FirstEnergy conceded there would be no reason why the Companies cannot continue to serve as CSP if the Commission directed the Companies to do so (OELC Ex. 1; Tr. Vol. II at 298).

{¶ 201} Moving to the applicable credits that should be applied for the duration of ESP V, we again stress that the Commission was cognizant of the numerous reliability and economic development benefits created through the ELR program and attempted to balance such benefits with the potential costs experienced by both participating and non-participating customers. Multiple parties readily admit that the value attributable to the ELR program is difficult to ascertain with precision. Using this balanced approach, we

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29 The Commission expects this annual test event will be called regardless for those who choose to have FirstEnergy operate as their CSP.

hereby adopt a blended outcome, which merges the varying suggestions proposed by the Companies, Staff, OEG, OELC, and Nucor, as noted in the following table:

Year of ESP	Applicable Credit
1	$8/kW-month
2	$7/kW-month
3	$7/kW-month
4	$6/kW-month
5	$6/kW-month

As discussed above, these credits are subject to a reduction of $2/kW-month for those customers who choose to obtain their own CSP.

{¶ 202} These credit amounts represent a balance of the various positions raised during this proceeding that seek to maximize participation in the program while minimizing costs paid by non-participants (Staff Ex. 10 at 26). We first recognize that there are several reasons why the current $10/kW-month credit should not be maintained over the course of ESP V, as suggested by Nucor and OEG. Given our decision regarding customers having the option to retain their own CSP beginning in the second year of the ESP, the prospect of earning PJM revenues that would not otherwise have been available would ease a reduction of the annual credit amount (Staff Ex. 10 at 21-24; Tr. Vol. VIII at 1680). Further, as OCC notes, at the time the current $10/kW-month credits were approved, Ohio EDUs were required to meet annual peak demand reduction targets. *ESP IV Case*, Opinion and Order (Mar. 31, 2016) at 72. As that requirement is no longer in place, we agree one portion of the program's value no longer exists and that should be taken into consideration when setting the credit amounts. R.C. 4928.66. Staff also raised its analysis demonstrating that current $10/kW-month credit amounts vastly exceed PJM clearing prices over the last decade, registering on average about $3.40/kW-month, thus necessitating a decrease in the credit amounts (Staff Ex. 10 at 24; Tr. Vol. XIV at 2574). Further, there has been no demonstration that reducing the credit amounts would substantially impact participation levels in the ELR program, as evidenced by the current levels of credits and participation in AEP Ohio's comparable IRP-E program (Tr. Vol. XIV at 2588).[30]

{¶ 203} Despite these reasons to reduce the credit amounts, however, we cannot ignore the reliability and economic development benefits discussed above, and we must be mindful of whether the credit amounts will continue to incentivize customers to participate in the program to harness these notable benefits (OELC Ex. 32 at 46-47, 49-51; Nucor Ex. 1 at 12-14; OCC Ex. 2 at 9; Tr. Vol. VII at 1463-64). Further, even though Staff argues OEG and OELC overstate that ELR participants are subject to "unlimited curtailments" from PJM and the Companies, when, in reality, curtailments have been scarce, we recognize there is no distinct limit in the program and ELR participants assume the risk to curtail regardless of how many actual events are called (Tr. Vol. II at 317, 345). Additionally, as noted earlier, there are differences between the ELR program and PJM demand response programs. One significant difference is that the ELR program subjects participating customers to curtailments at any time and for any duration, whereas curtailments in the PJM program are limited to certain periods. Another difference is that the ELR program subjects participants to interruption for events, including local distribution system reliability events, that are in addition to reliability events that allow PJM to require interruptions. These differences also support maintaining a higher credit to incentivize participation. (OELC Ex. 32 at 40; Tr. Vol. XIV at 2526.) Furthermore, while Nucor indicated a minimum threshold of $8/kW-month should be set, it provides no basis or analysis for why that credit amount would be appropriate or if that credit amount would prevent ELR participants from leaving the program (Nucor Ex. 1 at 16).

{¶ 204} Taking all of these considerations together, we believe the adopted credit amounts will continue to harness the notable reliability and economic development benefits associated with the ELR program while minimizing the cost paid by non-participants.

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30 Notably, no party, including FirstEnergy, offered an analysis as to what level of credit reduction may cause Rider ELR customers to leave the program (Nucor Ex. 1 at 14-15; Tr. III at 548).

Further, by adopting a more gradual reduction of credit amounts than that proposed by Staff, we specifically address concerns raised by Nucor, OEG, and OELC regarding potential rate shock by ELR participants.

{¶ 205} Consistent with our earlier findings, we note that a balancing of competing interests is also necessary to determine the proper size of the ELR program going forward. Specifically, the Commission must weigh the ability of customers to have open access to participate in offered utility programs with the understanding that applying caps on participation within those programs will mitigate bill impacts for nonparticipating customers. Overall, there appears to be a consensus amongst parties wishing for the ELR program to continue that it also be expanded in ESP V; however, we cannot support unlimited participation, as suggested by OELC (OMAEG Ex. 1 at 4; OELC Ex. 32 at 54; Staff Ex. 10 at 26-27; Tr. Vol. VIII at 1656; Tr. Vol. IX at 1776; Tr. Vol. XII at 2118, 2132). We find the Commission has struck this appropriate balance by affording customers wishing to participate in the program the opportunity to file a reasonable arrangement application for Commission approval. *See, e.g., In re the Application of for Establishment of a Reasonable Arrangement between the City of Akron, Ohio and Ohio Edison Co.*, Case No. 23-798-EL-AEC, Finding and Order (Feb. 21, 2024). As such, we will decline to expand the ELR program outside of this well-established process, consistent with AEP Ohio's IRP-E program. *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at 32-33.

{¶ 206} We also recognize that a variety of additional recommendations were made for the ELR program. For instance, Staff recommends simplifying cost recovery for the program, suggesting that all ELR program costs be recovered through Rider EDR by shifting what was previously recovered through Rider DSE1 as a new component of Rider EDR, with the same allocation currently being used under Rider DSE1. Staff also notes this proposal would allow Rider DSE to be removed from the Companies' tariffs once there is a final reconciliation of Rider DSE2. (Staff Ex. 10 at 19-20.) OEG supports Staff's position to move the costs associated with the ELR program to Rider EDR. We also find this to be a reasonable suggestion and direct the Companies to implement these changes for the ELR program. OEG also requests that the Commission maintain the current requirement for curtailments for distribution and transmission emergency events, instead of limiting it to distribution events, as suggested by the Companies (Tr. Vol. XIV at 2523-26). We also agree with this suggestion, noting that AEP Ohio's IRP-E program allows the utility to interrupt for both transmission and distribution emergencies (Tr. Vol. XIV at 2529). *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at 32. Finally, both OEG and OELC contend that the penalty for non-compliance should be modified to eliminate the ECE charge, noting it can be quite excessive and customers are already subject to several penalties in the Rider ELR tariff (OEG Ex. 3 at 19; OELC Ex. 32 at 40; Tr. Vol. II at 333-336; Tr. Vol. XIV at 2527-28). OEG and OELC suggest that the penalty for non-compliance should be modified to eliminate the ECE charge (OEG Ex. 3 at 19). We agree there appear to be sufficient penalties in place for customers who fail to curtail when called upon without imposing the additional ECE charge.

{¶ 207} In summary, the Commission finds that our modifications to the ELR program credits over time would lessen the cost of the program while ensuring the important reliability and economic development benefits provided by the program are maintained in the future for the benefit of all of FirstEnergy's customers.

N. Energy Efficiency Plan and Rider EEC

{¶ 208} The Companies are proposing a comprehensive portfolio of EE/PDR programs, which they allege are authorized in an ESP under R.C. 4928.143(B)(2)(i) and foster the policy set forth in R.C. 4905.70.[31] The Companies' proposed EE/PDR plan will initially run for a four-year term and will include residential and non-residential programs. The Companies assert that the proposed EE/PDR programs will enable customers to use

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[31] R.C. 4905.70 states, in pertinent part, that the Commission "shall initiate programs that will promote and encourage conservation of energy and a reduction in the growth rate of energy consumption, promote economic efficiencies, and take into account long-run incremental costs."

electricity more efficiently and save on their electric bills, and support energy efficiency for low-income customers, load control, and energy management for business customers. The EE/PDR plan includes four residential programs: (1) Residential Rebates and Appliance Recycling, (2) Energy Education, (3) Low-Income Energy Efficiency, and (4) Demand Response for Residential (Co. Ex. 5 at 4). Under the Residential Rebate program, the Companies state that residential customers can receive rebates and discounts for purchasing certain qualified ENERGY STAR energy efficient appliances and equipment, as well as choose to participate in appliance recycling programs (Co. Ex. 5 at 11-12). Next, the Companies state the Energy Education program will engage and educate residential customers about energy efficiency and conservation through Home Energy Reports and School Education. Through the Home Energy Reports, FirstEnergy customers will receive monthly, customized reports regarding their energy usage, including an analysis of their usage over time as well as specific tips and recommendations for reducing their energy usage. The School Education component will consist of a classroom-based education program delivered by school educators that will be focused on energy efficiency education and awareness to encourage conservation at home. (Co. Ex. 5 at 14.) FirstEnergy's EE/PDR Plan also includes the Low-Income Energy Efficiency program, which the Companies note is a continuation and expansion of the existing Community Connections program and will be available to customers up to 200% of the federal poverty level. Through this program, qualifying low-income customers will have the opportunity to receive energy efficiency and weatherization measures, upgrades, and education at no additional cost, as well as be able to undergo energy audits designed to promote a comprehensive approach to energy efficiency. (Co. Ex. 5 at 17-18.) The final program, the Demand Response for Residential program, will consist of Behavioral and Load Control components. The Companies explain that the Behavioral component will be available to eligible AMI customers, who will receive, on a day-ahead-basis, notification messages to motivate them to reduce usage during peak demand days, with feedback following the event. The Companies add that the Load Control component will be available to all customers with program eligible devices that agree to allow a vendor selected by the Companies to control, cycle, and/or optimize the use of their air conditioner, or potentially other equipment, through a program eligible device. Importantly, however, the Companies note that customers will retain the ability to override control of their devices, without risk of financial penalty. (Co. Ex. 5 at 19-20.)

{¶ 209} The Companies' Application also provides a program for non-residential customers, the Energy Solutions for Business program, which includes three components designed for commercial and industrial customers: rebates for prescriptive equipment, incentives for custom projects, and energy audits. The rebates will operate in essentially the same manner as the Residential Rebates program, with the major difference being the type of equipment eligible for rebate or discount. The custom project component will offer customers performance-based incentives to retrofit or install specialized equipment, processes, and applications to reduce both energy usage and demand. The energy audit component will provide customers with an incentive for completing a detailed energy management audit focused on the energy use of their business, with the goal of installing more efficient equipment, improving the energy efficiency of the buildings, and providing business customers with energy usage information that will help them to implement ongoing energy management strategies. (Co. Ex. 5 at 22-23.) FirstEnergy also explains that large, non-residential customers will have the option to opt-out of these programs (Co. Ex. 5 at 8). Those that opt out would no longer pay the Rider EEC charges, but could no longer participate in the rebate programs offered under the EE/PDR plan. Additionally, once a customer obtains a rebate from the EE/PDR plan, the customer would be precluded from opting out. FirstEnergy claims that this opt-out process "will entice greater efficiency gains and better advance the state policy objectives." (Co. Ex. 5 at 25). The Companies plan to contract with separate implementation vendors for residential and non-residential programs described above, who will ultimately be responsible for directly administering and managing delivery of the program, including, among other responsibilities, designing, marketing, validating eligibility, and conducting outreach to secure partnerships for each respective program (Co. Ex. 5 at 12, 15, 18, 20-21, 23-24).

{¶ 210} The Companies' Application introduces a new rider, the Energy Efficiency Cost Recovery Rider (Rider EEC), to recover the EE/PDR plan's costs. Though the programs would only be available for four years, the Companies propose cost recovery through Rider EEC to be spread out over eight years, with applicable carrying charges, and will be subject to annual regulatory review, audit, and reconciliation. Similar to the Companies' earlier arguments regarding the benefits of riders, FirstEnergy notes that the rider mechanism proposed will: (1) provide enhanced transparency to customers through annual updates, reconciliations, and annual audits, (2) mitigate bill impacts and promote gradualism in rates by spreading the costs over an eight-year period; and limit cost recovery through annual caps based on the program's annual approved budget (Co. Ex. 3 at 16-18; Tr. Vol. IV at 871). Further, the Companies assert that Rider EEC presents another opportunity for the Companies to lessen bill impacts by proposing to bid the EE/PDR programs' energy efficiency resources into the PJM forward capacity market, with 80 percent of the resulting net revenues to be used to offset the EE/PDR costs (Co. Ex. 5 at 30).

{¶ 211} FirstEnergy contends that the proposed EE/PDR plan and Rider EEC are authorized under R.C. 4928.143(B)(2)(h) and (i). In relevant part, R.C. 4928.143(B)(2)(h) and (i) authorize a utility to include in its ESP, "without limitation," "provisions regarding the utility's distribution service" and "provisions under which the electric distribution utility may implement * * * energy efficiency programs," respectively. FirstEnergy asserts that the EE/PDR plan falls squarely within the type of "energy efficiency program" contemplated by R.C. 4928.143(B)(2)(i). The Companies also argue that the programs directly relate to the Companies' provision of distribution service, as a major objective of the EE/PDR plan is to encourage customers to reduce their energy usage during peak periods, specifically mentioning the proposed Demand Response for Residential program. Further, the Companies assert these programs will reduce stress on the grid during these peak periods; they will also directly improve reliability across the distribution system. R.C. 4928.143(B)(2)(i) authorizes a utility to allocate energy efficiency program costs "across all classes of customers of the utility and those of electric distribution utilities in the same holding company system." The Companies also allege the proposed Rider EEC is consistent with R.C. 4928.143(B)(2)(i), as it will align costs of the EE/PDR programs between residential and non-residential customers based on the estimated costs of the programs. The Companies maintain that these notable benefits of the EE/PDR plan, including programs specifically designed for low-income customers and significant environmental benefits, greatly outweigh the associated costs, as demonstrated by the Companies' conducted cost-benefit analyses. Specifically, the Companies aver that, with the average annual total cost of the $72.1 million,[32] the EE/PDR plan will result in up to $637.9 million in estimated benefits over the lifetime of the programs. (Co. Ex. 5 at 4-7, 10, 13.)

{¶ 212} Finally, in hopes to operate as efficiently as possible, the Companies have also proposed opportunities for collaboration with interested stakeholders and program evaluation. Specifically, the Companies suggest collaborative meetings to occur twice a year to discuss program implementation and performance. The Companies also agree to retain an expert third-party evaluation, measurement, and verification contractor, who will conduct annual impact and process evaluations of the proposed programs. Relatedly, the Companies also note that program results will be filed with the Commission on an annual basis, with a more comprehensive review to be taken place at the end of the programs' initial four-year term. Based on the results of the comprehensive review, the Companies reserve the ability to file an application with the Commission seeking to extend, modify, or terminate the EE/PDR plan, but clarify that these programs cannot be extended beyond the four-year term without Commission approval. (Co. Ex. 5 at 4, 30-31.) Accordingly, FirstEnergy requests that the Commission approve the proposed EE/PDR plan and Rider EEC, as they claim that they are both authorized under R.C. 4928.143 and include customer protections and other substantial benefits to customers.

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32 Over the span of the proposed eight-year term, this would equate to a total $288.5 million.

{¶ 213} Staff, citing recent Commission precedent, supports the Residential Energy Education, Low Income Energy Efficiency, and Demand Response programs, but not the Residential Rebates and Energy Solutions for Business programs. *Columbia Rate Case*, Opinion & Order (Jan. 26, 2023) at ¶56. Moreover, if its recommendation for a six-year ESP term is approved, Staff recommends that the Commission approve the programs for an initial three years, with the option for the Companies to request an extension of the programs at that time (Staff Ex. 3 at 3; Staff Ex. 8 at 22). Staff also makes several additional recommendations to the Rider EEC mechanism. Initially, Staff suggests that the Companies only be allowed to recover expenses that are already incurred, known, and measurable, and should not be permitted to utilize projected expenses in the calculation of the rider (Tr. Vol. XIV at 2435-2436). Second, based on the Companies' proposal to defer recovery of prudently incurred expenses over an eight-year period, Staff alleges that resulting deferral will cost residential customers around $39.8 million, which is approximately a 30 percent increase above the residential program costs (Staff Ex. 8 at 22-23). Staff reasons that a delay in recovering those costs will cost customers substantially more if the Commission approves carrying charges on the unrecovered expense balance and, as such, recommends that the Companies not be allowed to accrue carrying charges for deferring recovery of expenses that could have been recovered in a prior EEC filing (Staff Ex. 8 at 23). Finally, consistent with recommendations posed for other riders in this proceeding, Staff requests that the annual Rider EEC filing be docketed at least 60 days prior to its effective date to give Staff sufficient time to complete an initial review of the rider before its effective date (Staff Ex. 3 at 24). If the Commission adopts Staff's recommendations, the annual program budget should be $15,663,202 per year (Staff Ex. 3 at 4). Staff suggests its recommendations are aligned with recently approved energy efficiency programs, while also taking into account programs that are appropriate in size and scale to allow the Companies to provide customers with energy efficiency and demand response services (Staff Ex. 3 at 5).

{¶ 214} NRG, IGS, RESA,[33] OMAEG, Kroger, and OCC argue that the Commission should reject all of these programs, or, alternatively, adopt Staff's recommendation to approve only the low-income residential programs (RESA/IGS Ex. 1 at 9-18; RESA Ex. 16 at 14; OCC Ex. 4 at 3-14). Acknowledging that the state energy policy favors demand side management programs that protect at-risk populations, IGS and RESA contend that approval of the EE/PDR plan would allow a utility to implement a program that is funded involuntarily by customers through a non-bypassable rider. According to IGS, RESA, Kroger, and OMAEG, recent changes in Ohio law, and the Commission orders effectuating those changes, demonstrate that EDUs were not intended to continue to offer energy efficiency programs. R.C. 4928.66(G)(3). *See In re the Application of Duke Energy Ohio, Inc.*, Case Nos. 16-576-EL-POR, et al., Finding and Order (Feb. 26, 2020) at ¶1, Third Entry on Rehearing (Nov. 18, 2020) at ¶57, Entry (Dec. 30, 2020) at ¶¶10, 12; *In re the Application of Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case No. 16-743-EL-POR, Finding and Order (Nov. 18, 2020) at ¶ 8, 11. Relatedly, OMAEG and NOAC contend that, by only approving the low-income programs, the Commission would be aligning FirstEnergy's program offerings with those Commission-authorized programs of AES Ohio and AEP Ohio. *In re the Application of Ohio Power Co. for an Increase in Elec. Distribution Rates*, Case No. 20-585-EL-AIR, et al. (*AEP Ohio Rate Case), Opinion and Order* (Nov. 17, 2021) at ¶128; *AES ESP IV Case*, Opinion and Order (Aug. 9, 2023) at 33. OMAEG, OELC, and Kroger take particular issue with the Energy Solutions for Business program, arguing that an opt-out program where customers are included in the program unless or until they affirmatively opt-out[34] cannot be deemed to be voluntarily, especially when an opt-in mechanism was

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[33] RESA argues that, if the Commission approves anything, it should be limited to the low-income weatherization program (RESA/IGS Ex. 1 at 17). However, RESA raises many of the same arguments as those who alternatively would suggest approving all low-income programs proposed by the Companies.

[34] OMAEG, Kroger, and OELC also raise concerns with the opt-out mechanism, which has yet to be defined by the Companies, and state that customers will continue to be charged through Rider EEC until they have successfully opted out from the program. These parties add that the Companies have not committed to delay charging customers for the EE/PDR programs through Rider EEC until such time as customers have been made aware of the opt-out option and have had the opportunity to do so. (Co. Ex. 5 at 25; OMAEG Ex. 13; Tr. V at 993-99.)

just as feasible and, therefore, runs in direct contradiction to R.C. 4928.66(G)(3) (Tr. Vol. IV at 810, 825, 831, 836; Tr. Vol. V at 991-92). Given the considerable change in the applicable statutes, these parties contend that the Commission should find that it is not appropriate for EDUs, such as FirstEnergy, to implement EE/PDR programs.

{¶ 215} Instead, NRG, OELC, OMAEG, Kroger, RESA, NOAC, OCC, and IGS note that competitive retail electric service (CRES) providers and energy efficiency retailers, rather than utilities, are best suited to educate customers and provider incentives to increase energy efficiency awareness through the competitive market (RESA/IGS Ex. 1 at 16; OCC Ex. 4 at 14). In fact, these parties note that the Commission has repeatedly highlighted the importance of reserving energy efficiency and demand response issues for non-low-income consumers for the competitive markets. *See, e.g., In re the Commission's Investigation into the Implementation of the Federal Infrastructure Investment and Jobs Act's Demand Response PURPA Standard*, Case No. 22-1024-AU-COI, Finding and Order (Nov. 1, 2023) at ¶28; *Columbia Rate Case*, Opinion & Order (Jan. 26, 2023) at ¶56; *In re the Application of the East Ohio Gas Company dba Dominion Energy Ohio*, Case No. 21-1109-GA-ALT (*DEO Alternative Rate Plan Case*), Opinion & Order (Oct. 4, 2023) at ¶49; *In re the Commission's Review of the Rules in Ohio Adm.Code Chapter 4901:1-39*, Case No. 22-869-EL-ORD, Finding and Order (Nov. 30, 2022); *In re the Application of Duke Energy Ohio, Inc.*, Case Nos. 20-1013-EL-POR, et al., Entry (June 17, 2020); *In re the Application of Duke Energy Ohio, Inc.*, Case Nos. 21-887-EL-AIR, et al.(*2021 Duke Rate Case*), Opinion and Order (Dec. 14, 2022) at ¶¶71–72, 173); *In re the Application of Duke Energy Ohio, Inc.*, Case Nos. 16-576-EL-POR, et al., Entry (Dec. 30, 2020) at ¶9. RESA contends that CRES providers are an inherently better choice to offer these products, as "[m]arket participants must demonstrate value to residential customers to obtain their business, and competitive market forces will require market participants to continually better themselves and identify the products and services residential customers desire, provide value, and are affordable." (RESA Ex. 16 at 7, 12). IGS, OCC, RESA, and NOAC add that EE/PDR products are already being provided by the competitive market, such as energy audits, LED lighting, onsite solar and battery solutions, and 100 percent renewable supply contracts, allowing consumer choice in their energy management decisions where only participants pay for the product and services. Not only are these products offered by suppliers, but OCC and RESA specifically note that several retailers, such as Home Depot, also offer smart thermostat rebate programs and energy efficiency information is readily available through numerous state and federal programs. (OCC Ex. 4 at 7; RESA Ex. 16 tat 6, 8-11; RESA/IGS Ex. 1 at 13-15; Tr. Vol. IV at 874-75, 878-79; Tr. Vol. X at 1797, 1801.) OCC witness Shutrump emphasized in her testimony that Commission "rulings have increasingly relied on competitive markets for energy efficiency instead of utility programs, finding that the market for energy efficiency services has developed to the extent that 'consumers should be aware of and sufficiently knowledgeable to explore the availability' and benefits of energy efficiency through the competitive market." (OCC Ex. 4 at 3, 14). Further, OCC claims that the $99.6 million[35] for non-low-income energy efficiency programs is improper because "these programs are not benefiting all consumers and should not be subsidized by utility consumers." (OCC Ex. 4 at 6). RESA, OMAEG, and Kroger also take issue with the overall cost of the proposed EE/PDR plan, noting that the Commission explicitly cited affordability as a key reason for denying non-mandatory EE/PDR programs and stated that "subsidization of the costs of these programs across Dominion's footprint acts as a burden on the Company's ratepayers." *DEO Alternative Rate Plan Case*, Opinion and Order (Oct. 4, 2023) at 18. OMAEG and Kroger also argue that the mere fact that FirstEnergy's proposed $288.5 million of EE/PDR program costs need to be collected over 11 years to be considered "reasonable" indicates that the costs of these programs are excessive and unjust and unreasonable (Tr. Vol. II at 355, 376; Tr. Vol. III at 531). Further, RESA again emphasizes that rejecting FirstEnergy's proposed EE/PDR plan will not prevent customers from obtaining products and services to meet their individual needs and which of them they deem affordable given their circumstances (RESA Ex. 16 at 6-7). However, RESA and OELC caution that allowing the EE/PDR plan to be approved as

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35 Total residential program cost of $134 million minus low-income program cost of $34.4 million (Co. Ex. 5 at Attach. ECM-2).

proposed may have a negative impact on the competitive market's ability to offer these products, as FirstEnergy will be operating under a subsidized program and will have much easier access to customer data, and may ultimately lead to an overall decrease in the number of products offered to customers in the FirstEnergy territories (RESA/IGS Ex. 1 at 15; RESA Ex. 16 at 13-14; Tr. Vol. X at 1826-27). OMAEG and OELC also reference R.C. 4928.02(H) in support of the Commission's stance to rely on market-based approaches because this statute provides that it is the state's policy to prohibit anticompetitive subsidies. Accordingly, NRG, OMAEG, Kroger, OCC, and IGS contend that allowing FirstEnergy to implement its proposed programs not related to low-income customers would be inconsistent with Ohio energy policy, anti-competitive within the marketplace, and problematic for consumers.

{¶ 216} While not opining on the residential programs, OELC argues that the Commission should not authorize FirstEnergy's proposed Energy Solutions for Business program for many of the reasons stated above. In addition, OELC observes that larger customers that would qualify for the Energy Solutions for Business program already have multiple options available to undertake energy efficiency or demand reduction initiatives that suit their individual needs and may not participate in the various components of the program (Co. Ex. 5 at 7-8, 23; Tr. Vol. IV at 823-24). Moreover, OELC argues the anticipated cost of the Energy Solutions for Business program, roughly $154.3 million in total, is incomplete, due to a number of unknown variables, such as the impact of new equipment that is subsequently available in the market and determined by the selected vendor to qualify for rebates (Co. Ex. 5 at Attach. ECM-3; Tr. Vol. III at 662-64, 675, 680-81). OELC and Nucor further argue that FirstEnergy already had the opportunity to promote nonresidential customers' energy efficiency during ESP IV, with roughly $20 million of FirstEnergy's $24 million commitment remaining unspent at the time of the hearing in this proceeding. However, OELC points out a notable difference in that the proposed program in ESP V will utilize customer money, as opposed to shareholder funds. (Tr. Vol. IV at 845-46, 851-52; Tr. Vol. V at 977-78, 984-85; OELC Ex. 8 at 5-8.)

{¶ 217} Finally, RESA takes issue with the touted benefits associated with the EE/PDR plan. While claiming its $375 million EE/PDR program will provide customers benefits based on FirstEnergy's assumed level of savings largely causing avoided future energy and capacity market costs, RESA observes that FirstEnergy admitted that its witness sponsoring the energy and capacity market forecasts was not an expert in in either energy or capacity price forecasting (Co. Ex. 5 at Attach. ECM-4; Tr. Vol. V at 946-47). As such, RESA asserts the Commission should not give any weight to this testimony.[36] RESA also notes a potential flaw with the smart thermostat demand management program is the assumption that it could help reduce PJM capacity prices, since FirstEnergy's EE/PDR plan will have no demonstrable effect on the PJM capacity auction clearing price with the approximately 16,000 MW already being offered into the BRA above what cleared, compared to the projected annual peak demand reduction of 111.3 MW cited by FirstEnergy (RESA Ex. 17 at 18-19; Co. Ex. 5 at Attach. ECM-2). Moreover, RESA contends that the record further demonstrates that within the ATSI zone, there is also an excess of capacity resources available to PJM to support reliability in the FirstEnergy footprint, citing the 248.6 MW difference between what was offered and what cleared in the BRA for the current PJM delivery year.[37] (RESA Ex. 17 at 10). Relatedly, RESA also notes that the Companies failed to conduct or produce any studies or analysis demonstrating that the smart thermostat demand response program would provide any reliability benefits (RESA Ex. 11; RESA Ex. 12; Tr. Vol. II at 371).

{¶ 218} NRG suggests that, instead of adopting the EE/PDR plan at a cost to customers of approximately $288.4 million over four years, the Commission should adopt NRG's proposal to move all SSO customers with an advanced meter to a time-varying rate.

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36 In fact, RESA requests that the Commission should overturn the ALJ's rulings during the hearing allowing a majority of the testimony to stand, over the objections of RESA's counsel, which is specifically discussed elsewhere in this Opinion and Order.

37 RESA notes that, for the BRA associated with the current PJM delivery year, 1,100.1 MW of capacity in the ATSI zone was offered into PJM with PJM only clearing 851.5 MW.

Additionally, if the Commission does decide to adopt any type of smart thermostat program, NRG suggests that the Commission should specifically preclude FirstEnergy from selling the demand response in PJM markets. Further, NRG also suggests that the Commission should create a working group for FirstEnergy, Staff, and CRES providers to collaborate on any smart thermostat program. (RESA/IGS Ex. 1 at 15-18.) Similarly, NRG, IGS, and RESA note that any data utilized by FirstEnergy or provided to its third-party vendors should be provided to CRES providers in the same manner to avoid harm to the competitive market caused by asymmetric information access. RESA, IGS, and OELC go even further to allege that the current structure of FirstEnergy's EE/PDR plan creates an unlevel playing field where FirstEnergy and its vendor have unequal access to customer data to develop programs that generate a higher degree of savings, in direct contradiction to the spirit of the corporate separation requirements and state energy policies that support robust and fair competition (RESA/IGS Ex. 1 at 14-15; Tr. Vol. IV at 881-83; Tr. Vol. V at 943-44, 1044). Ohio Adm.Code 4901:1-37-04; R.C. 4928.17; R.C. 4928.02(L).

{¶ 219} While it supports Staff's recommendation to approve the low-income programs proposed by FirstEnergy, OCC also recommends several changes to optimize the alleged benefits and further protect consumers, such as competitive bidding for any outside service providers and developing more defined parameters for the $36 million in shareholder-funded programs to foster coordination between existing and new programs (OCC Ex. 3 at 3, 5; OCC Ex. 4 at 14). OCC further recommends that service disconnections should be reported at the zip-code level to provide guidance on program targeting efforts (OCC Ex. 3 at 9). Finally, OCC also notes that these low-income programs should only be approved if they are available for the entirety of ESP V.

{¶ 220} ELPC, OEC, and CUB wholly support FirstEnergy's proposed EE/PDR programs. ELPC, OEC, and CUB initially argue that the legislature's repeal of mandatory energy efficiency programs previously codified R.C. 4928.66 should not affect the Commission's decision in this case. According to these parties, while the repeal eliminated the mandate that utilities run energy efficiency programs, it left intact other important statutory provisions that allow for voluntary programming. For instance, ELPC notes that R.C. 4928.143 specifically authorizes utilities to include "energy efficiency programs" in ESP applications. R.C. 4928.143(B)(2)(i). While advocating for several riders to be rejected until the upcoming base rate case, OEC argues that customers cannot afford to wait to implement these cost-effective, grid reliability programs that FirstEnergy does not currently provide, adding that the ESP is an effective mechanism for implementation. CUB also emphasizes that the repeal did not impact the state's energy policy codified in R.C. 4928.02 or the requirement of the Commission to "initiate programs that will promote and encourage conservation of energy and a reduction in the growth rate of energy consumption." R.C. 4905.70. (Co. Ex. 5 at 9.)

{¶ 221} Further, ELPC agrees that the Companies' energy efficiency programs will benefit ratepayers in two specific ways: (1) by reducing their energy usage and, therefore, lowering their bills; and (2) by reducing peak demand and allowing the utility to avoid costly investments in generation capacity and the grid (Co. Ex. 5 at 7-8). Moreover, ELPC contends that the record demonstrates that FirstEnergy's energy efficiency programs would provide both of these benefits to its customers by enabling more customers to switch to energy efficient appliances and by encouraging more efficient energy use practices. ELPC alleges, consistent with FirstEnergy witness Miller's testimony, the Residential Rebates program will utilize heat pumps and smart thermostats, as well as target qualified ENERGY STAR appliances, that will maximize the benefits of the program to customers (Co. Ex. 5 at 11). In fact, ELPC highlights that the Companies expect to support the purchase of 2,000 heat pumps and 2,000 smart thermostats annually (Co. Ex. 5 at Attach. ECM-3). Ultimately, ELPC argues that the Companies' energy efficiency programs create the opportunity for significant annual energy and demand savings for both residential and non-residential customers (Co. Ex. 5 at 17-18, 22). According to FirstEnergy witness Miller, the programs will amount to 247,399 MWh of annual energy savings and 38 MW of annual demand savings (Co. Ex. 5 at Attach. ECM-2), which ELPC claims will benefit participating and non-participating ratepayers alike. ELPC further contends that the costs associated with the

EE/PDR plan are far outweighed by the benefits, as demonstrated by FirstEnergy witness Miller's analysis. As he testified, the Companies EE/PDR plan, as a whole, will yield $139 million in net benefits under the most conservative benefit-cost test, the Total Resource Cost (TRC) test (Co. Ex. 5 at 27, Attach. ECM-4).[38] ELPC adds this considerable net benefit fails to include additional important benefits attributable to the EE/PDR plan, such as the health and environmental benefits of reduced air pollution from lower energy use (Co. Ex. 5 at 27-28). To bolster the findings under the TRC test, ELPC and CUB note that FirstEnergy also produced cost-benefit analyses under other tests historically used by the Commission, the Societal Cost Test (SCT) and the Utility Cost Test (UCT), which also found significant benefits associated with the plan (Co. Ex. 5 at 27-28). CUB, OEC, and ELPC note the uncontested results under all three tests show that the proposed programs are projected to be cost-effective at the portfolio level, scoring a 1.3 benefit cost ration under the TRC test, and 2.1 under both the UCT and SCT, and estimated to result in between $139 million and $524 million in net benefits to customers (Co. Ex. 5 at 28; Tr. Vol. XIII at 2306-09). OEC also notes the significance that FirstEnergy already has a rider dedicated to demand response for commercial and industrial customers but has no similar program for residential customers (Co. Ex. 1 at 12). Reiterating many of the same points discussed above in favor of continuing Rider ELR, OEC notes that a residential demand response tool is needed when the participating industrial and commercial demand response customers do not cover all needed areas of the distribution grid (OELC Ex. 1 at 1; OELC Ex. 3 at 1-2, 27). Given recent events, OEC asserts that FirstEnergy must initiate the energy efficiency programs proposed in its Application to begin preparing the grid for future high demand and generation failures due to severe weather.

{¶ 222} CUB and OPAE also support the proposed low-income energy efficiency program, which is a continuation of the previously Commission-approved Community

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[38] Under the TRC test, which "examines benefits and costs from the combined perspective of the utility system and participants," Mr. Miller testified that the Residential Rebates provides net benefits of roughly $15 million while Energy Education provides net benefits of $5.5 million.

Connections program (Co. Ex. 3 at 17). OPAE and CUB contend that these types of programs are vital for low-and-moderate income customers because low-income customers have disproportionately high energy burdens compared to non-low-income households, adding that low-income households spend three times more of their income on energy bills as non-low-income households (OPAE Ex. 1 at 4). OPAE claims these customers have fewer options to control energy costs, and the proposed continuation of Community Connections can provide these opportunities, which in turn, can help customers lower their bills. Further, OPAE and CUB allege the weatherization services provided through Community Connections may offer long-term solutions to energy affordability, which frees up resources for low-income families for other necessities. (OPAE Ex. 1 at 5.) Despite state weatherization programs such as the Home Weatherization Assistance Program (HWAP), OPAE maintains that Community Connections is still a necessary program which maximizes the impact of the HWAP program (OPAE Ex. 1 at 7). FirstEnergy has proposed to continue the program with an increased budget of $8.6 million per year over the proposed four-year term of the EE/PDR Plan, which is approximately $2 million more than when the program was last authorized. With the costs of providing weatherization services rising since that time, OPAE contends that the increase in funding is necessary; although, OPAE would also suggest that the Commission consider increasing the budget, as well as increasing the income threshold, consistent with the Commission's decisions in other cases such as the *AES Ohio ESP IV Case*, ensuring the maximum number of customers can receive these services. Contrary to Staff's overall position on length of the EE/PDR programs, OPAE requests that the Commission set the term of the proposed continuation of the Community Connections program consistent with the overall term the Commission approves for the ESP (Staff Ex. 3 at 3). OPAE argues there is no benefit associated with shortening the duration of this program from the entire ESP V period, as it may lead to budgeting and planning problems for program administrators. Further, OPAE notes that the Commission approved Community Connections to be funded from 2016 through 2023 in the current ESP.

{¶ 223} ELPC, OEC, and CUB add that parties opposing the Residential Rebates and Energy Solutions for Business programs provide no substantive analysis or justification for their opposition to those programs. Instead, ELPC argues these parties simply cite to Commission precedent as the basis for rejecting these valid programs. ELPC finds particular concern with reliance on the *Columbia Rate Case* as a basis for rejecting these programs, arguing that parties mischaracterize the Commission's decision in that case, where Columbia had proposed an efficiency program that it withdrew as part of a stipulation. ELPC notes that the Commission's order in *Columbia Rate Case* does not set forth a general framework for the Commission's approval of energy efficiency programs or expressly preclude utility-managed rebate programs. Instead, argues ELPC, the *Columbia Rate Case* decision declares that the Commission will consider energy efficiency programs on a "case-by-case basis, based upon the evidence in the record of each proceeding." *Columbia Rate Case*, Opinion & Order at ¶¶54, 205. However, ELPC and CUB argue that parties opposing these two programs, including Staff and OCC, do not provide any independent analysis or probative evidence justifying their rejection (Tr. Vol. XIII at 2299-3001; OCC Ex. 4 at 4). Instead, ELPC and CUB argue that, in this case, the record contains substantial evidence demonstrating that the Companies' energy efficiency programs will benefit ratepayers and should approve the FirstEnergy program.

{¶ 224} In response to arguments that the competitive market will provide commensurate benefits as those that could be derived from the EE programs, ELPC, OEC, and CUB contend that the record evidence in this case shows that the competitive market has failed to furnish energy efficiency programs similar to what the Companies propose, despite the fact that the Companies stopped providing such programs more than three years ago. ELPC, OEC, and CUB first allege that the record does not support a finding that CRES providers currently offer or have any plans to offer energy efficiency programs that generate savings and benefits similar to the Companies' proposed EE/PDR plan, noting that, while various witnesses testified that FirstEnergy's energy efficiency offerings are "competitive products," those witnesses could not identify CRES providers in the FirstEnergy service area that offer equivalent programs or explain how FirstEnergy's programs would restrict CRES providers from offering comparable products (RESA/IGS Ex. 1 at 11; RESA Ex. 16 at 6-7; Tr. Vol. IX at 1713; Tr. Vol. X at 1828-29; Tr. Vol. XIII at 2163-64). ELPC and CUB further claim that the record does not support OCC's position that retailers like Home Depot provide sufficient access to energy efficient products to realize comparable benefits in the absence of the Companies' rebate programs, emphasizing the data OCC witness Shutrump relies upon is not specific to Ohio and apparently includes sales enabled by utility-run rebate programs in other states (OCC Ex. 4 at 7; Tr. Vol. IX at 1720). CUB adds that, even if these retailers were a feasible option, it is unreasonable to rely on a decentralized approach of unvetted programs from varying retailers and suppliers and expect to achieve the economies of scale necessary to realize comparable benefits to the Companies' proposed EE/PDR plan. Moreover, ELPC notes that no party in the proceeding, including OCC, conducted or produced any analyses to demonstrate the sales of energy efficient appliances in Ohio have declined in the absence of utility rebate programs (Tr. Vol. IX at 1719). ELPC and OEC contend an even greater deficiency of demand response programs currently exists in the competitive market, despite the significant impact they can have in reducing peak demand. Noting FirstEnergy witness Miller's testimony, ELPC notes that the record evidence demonstrates that the Demand Response for Residential program is a particularly efficient method of reducing strain on the grid at times of peak demand, allowing FirstEnergy to avoid otherwise necessary investments in generation, transmission, and distribution capacity. In total, FirstEnergy estimates that the Demand Response for Residential Program will generate 29.7 MW of demand savings annually, with annual costs of $8.8 million and yielding benefits of $17 million. (Co. Ex. 5 at Attach. ECM-2, Attach. ECM-4.) ELPC and OEC contend that the Companies are uniquely positioned to provide the benefits of this residential demand response program, given concessions during the hearing in which no witness could identify any CRES provider that currently operates a residential demand response program in Ohio and, in fact, alluded to CRES providers facing numerous "structural" issues in providing such programs to residential customers (RESA Ex. 16 at 9-10; Tr. Vol. IX at 1697; Tr. Vol. X at 1801, 1817; Tr. Vol. XIII at 2164). As such, ELPC and CUB opine that, in the absence of the Companies' EE/PDR plan, FirstEnergy's customers will have no opportunity to participate in comparable programs (Co. Ex. 5 at 26). OEC cautions the Commission to adopt only a portion of the EE/PDR plan, as this approach would undoubtedly have a lesser impact on FirstEnergy's distribution system, leaving some customers without viable options (Tr. Vol. IX at 1705, 1710; Tr. Vol. XIII at 2308).

{¶ 225} While generally agreeing with the alleged benefits of the Companies' EE/PDR proposal, Armada requests various modifications to ensure the greatest possible benefit from the program. First, Armada contends that the load reduction programs should be technology neutral and allow participants to enroll any demand-capable technology. By expanding the load control demand response program to include technologies based on device capabilities, rather than a prescribed device, Armada argues the Commission could ensure program success and efficiency, adding that technologies like demand-response-capable water heaters are less invasive than smart thermostats. (Armada Ex. 1 at 6, 16.) Further, Armada notes that allowing a more diverse selection of options for customers to participate will generate higher participation rates, increasing the benefits attributable to the programs. Armada also advocates that the unused portion of the $24 million in shareholder dollars from ESP IV designated for energy conservation, economic development and job retention should be used for the EE/PDR programs, furthering the intended purpose of energy conservation and economic development identified by Company witness Miller (Tr. Vol. V at 975; Co. Ex. 5 at Attach. ECM-4). Finally, Armada suggests the Companies should develop a secure data sharing program to facilitate the aggregation of residential customers to participate in PJM markets (Armada Ex. 1 at 7-8; Tr. Vol. IV at 910).

{¶ 226} Walmart does not present an opinion as to the proposed residential programs, but suggests that, if the Commission approves the Energy Solutions for Business program, we should also adopt the reporting recommendations of Walmart witness Perry. Among other things, Walmart recommended that the Companies track the level of participation by eligible customers, including the number of opt-outs, providing the

Companies, parties, and Commission with valuable insight into the level of participation and interest in the program. (Walmart Ex. 1 at 12.)

{¶ 227} In response to Staff's opposition to spreading the costs of the EE/PDR plan over an eight-year period, as well as precluding carrying charges, the Companies request that the Commission reject Staff's arguments as they will negatively impact customers. First, the Companies highlight that shortening the term of cost recovery would be inconsistent with gradualism, which Staff advocates for in other areas, and, second, rejecting the recovery of carrying costs fails to consider the regulatory lag associated with recovering EE/PDR program costs.

{¶ 228} The Commission initially recognizes that the statutory changes identified by several parties regarding the legislature's repeal of mandatory energy efficiency programs previously codified by R.C. 4928.66 will not affect our decision in this case. As noted by ELPC, OEC, and CUB, the repeal eliminated the mandate that utilities run energy efficiency programs, leaving intact other important statutory provisions that allow for voluntary programming, if approved by the Commission. For instance, these parties note that the state's energy policy codified in R.C. 4928.02 or the requirement of the Commission to "initiate programs that will promote and encourage conservation of energy and a reduction in the growth rate of energy consumption." R.C. 4905.70. (Co. Ex. 5 at 9). Further, as we have previously indicated, the Supreme Court of Ohio has held that R.C. 4928.02 does not impose strict conditions on the Commission's actions or authority when considering applications before it. *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at ¶153, citing *In re Application of Ohio Power Co.*, 155 Ohio St.3d 326, 2018-Ohio-4698, 121 N.E.3d 320, at ¶19. Additionally, specific to our purposes in considering the Companies' Application, R.C. 4928.143 explicitly authorizes utilities to include "energy efficiency programs" in ESP applications. R.C. 4928.143(B)(2)(i). As such, we are not statutorily precluded from considering the EE/PDR plan as part of ESP V and will, instead, evaluate each of the components, as proposed by the Companies, in light of recent Commission precedent. *In re* *the Commission's Review of the Rules in Ohio Adm.Code Chapter 4901:1-39*, Case No. 22-869-EL-ORD, Finding and Order (Nov. 30, 2022) at ¶12.

{¶ 229} The Commission finds that the Companies' proposed energy efficiency programs should be modified and approved. We will approve the proposed Low-Income Energy Efficiency program and the proposed Energy Education program as recommended by Staff (Staff Ex. 3 at 8). As noted by the Companies, the Energy Education program will educate residential customers about energy efficiency and conservation, including a component aimed to provide classroom-based education focused on energy education and awareness to encourage conservation at home. FirstEnergy witness Miller testified to projected benefits of the Energy Education program, noting the program is expected to provide 32,952 MWh in average incremental annual energy savings, 5.8 MW in average incremental annual demand savings, and $1.1 million in average annual incentives to customers, at an average annual total cost of $3.6 million. (Co. Ex. 5 at 14-16, Attach. ECM-2.) FirstEnergy's proposed Low-Income Energy Efficiency program likewise provides significant benefits and represents a continuation and expansion of the existing Community Connections program. Through this program, qualifying low-income customers[39] will have the opportunity to receive energy efficiency and weatherization measures, upgrades, and education at no additional cost, as well as be able to undergo energy audits designed to promote a comprehensive approach to energy efficiency. The Low-Income Energy Efficiency program is projected to provide 5,382 MWh in average incremental annual energy savings, 0.8 MW in average incremental annual demand savings, and $7.4 million in average annual incentives to customers, at an average annual total cost of $8.6 million over the 4-year term of the EE/PDR Plan. This amount represents an increase of approximately $2 million annually to provide program services to additional income qualified customers, estimating a total of 14,800 income qualified customers being able to participate. (Co. Ex. 5 at 17-19, Attach. ECM-2.) CUB and OPAE, two parties who represent the interests of low-

[39] This program will be available to customers up to 200 percent of the federal poverty level (Co. Ex. 5 at 17).

income residential customers, note their support of these programs, arguing that low-income customers have disproportionately high energy burdens compared to non-low-income householders (OPAE Ex. 1 at 4). Furthermore, we agree that the approval of the Low-Income Energy Efficiency program is consistent with the state policy of protecting at-risk populations, as codified in R.C. 4928.02(L). As such, we believe these two programs represent cost-effective energy efficiency measures that would not otherwise be available to FirstEnergy's residential customers.

{¶ 230} We also will adopt Staff's recommendation for the elimination of the Residential Rebate program and the Energy Solutions for Business program (Staff Ex. 3 at 8). Instead, and consistent with recent precedent, we agree with several of the points raised by NRG, OELC, OMAEG, Kroger, Nucor, RESA, NOAC, OCC, and IGS in opposition to these programs and find they are better suited for the competitive market, where both residential and non-residential customers will be able to obtain products and services to meet their individual needs. *See, e.g., In re the Commission's Investigation into the Implementation of the Federal Infrastructure Investment and Jobs Act's Demand Response PURPA Standard*, Case No. 22-1024-AU-COI, Finding and Order (Nov. 1, 2023) at ¶28; *Columbia Rate Case*, Opinion & Order (Jan. 26, 2023) at ¶56; *DEO Alternative Rate Plan Case*, Opinion & Order (Oct. 4, 2023) at ¶49; *In re the Application of Duke Energy Ohio, Inc.*, Case Nos. 20-1013-EL-POR, et al., Entry (June 17, 2020); *2021 Duke Rate Case*, Opinion and Order (Dec. 14, 2022) at ¶¶71–72, 173); *In re the Application of Duke Energy Ohio, Inc.*, Case Nos. 16-576-EL-POR, et al., Entry (Dec. 30, 2020) at ¶9. This is especially true for non-residential customers, as these customers already have multiple options available to undertake energy efficiency or demand reduction initiatives that suit their individual needs (Co. Ex. 5 at 7-8; Tr. Vol. IV at 823-24). Further, as to the affordability of such programs, we find that the annual budget of $56,465,014 proposed for these programs represents an excessive cost to ratepayers, especially given comparable programs are readily available in the competitive market (Co. Ex. 5 at Attach. ECM-2). *DEO Alternative Rate Plan Case*, Opinion and Order (Oct. 4, 2023) at ¶49.

{¶ 231} Ultimately, we agree with Staff witness Braun that the approach adopted in this Opinion and Order, which relies more heavily on the competitive market than utility programs to offer energy efficiency products, is consistent with the approach the Commission has adopted in recent cases while still offering low-income customers the opportunity to participate in energy efficiency programs that the competitive market may not provide (Staff Ex. 3 at 8-9). *Columbia Rate Case*, Opinion and Order (Jan. 26, 2023) at ¶56; *AEP Ohio Rate Case*, Opinion and Order (Nov. 17, 2021) at ¶¶128, 173; *DEO Alternative Rate Plan Case*, Opinion and Order (Oct. 4, 2023) at ¶49. Additionally, we find that Energy Education and Low-Income Energy Efficiency programs should remain in place for the full-five-year term of ESP V, as suggested by OCC and OPAE.

{¶ 232} Staff also recommends approval of the Demand Response for Residential program. We do not find that this program should be adopted. Instead, we direct the Companies to develop and propose a smart thermostat rebate program with an annual budget of $2,000,000 for the entire five-year term of ESP V, which represents a program of appropriate size and scale to be offered to FirstEnergy's residential customers at this time.[40] The evidence in the record demonstrates that smart thermostats are an essential tool which can facilitate market-based solutions for energy efficiency (Tr. Vol. IV at 906, 910; Tr. Vol. V at 1034-36, 1043-44; Tr. Vol. X at 1800-02, 1818-19, 1841-42). Further, the Commission has recently found such programs to strike a balance between the various objectives outlined in R.C. 4928.02, including the promotion of effective competition and ensuring all Ohioans maintain access to reliable electric service. *See AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at ¶153. Moreover, this cost-effective alternative to the Demand Response for

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40 We note that the Companies recently proposed a smart thermostat program in a stipulation in *the Grid Mod II Case*, which is currently set for hearing in June of this year. *Grid Mod II Case*, Joint Stipulation (Apr. 12, 2024). If the Commission were to approve this stipulation, nothing in this Opinion and Order precludes the Companies from combining the two programs provided that spending does not exceed the combined cap of the two programs. Parties will be able to opine on that issue during the hearing.

Residential program[41] will assist with the purchase of smart thermostats, thus providing participating residential customers another tool to better manage their electric usage and potentially reduce their electric bills and risk of disconnection. As noted above, improvements in affordability have been a factor the Commission has considered when evaluating proposed energy efficiency programs and it remains an important factor in our consideration of the Companies' Application. *DEO Alternative Rate Plan Case*, Opinion and Order (Oct. 4, 2023) at ¶49. A smart thermostat rebate program will encourage innovation and market access to demand-side management while at the same time provide FirstEnergy with the ability to take actions that will improve the distribution grid, promoting several principles outlined in R.C. 4928.02, including enhanced reliability performance.

{¶ 233} Given the directive to implement a smart thermostat rebate program, the Commission also accepts the suggestion of NRG, RESA, and IGS to create a working group for FirstEnergy, Staff, CRES providers, and other interested stakeholders (such as smart thermostat vendors) to collaborate to discuss implementation and ways to maximize the benefits associated with the program (RESA/IGS Ex. 1 at 15-18). The Commission also advises the working group that the smart thermostat rebate program contemplated by this Opinion and Order should consider the terms of the program adopted in AEP Ohio's latest ESP. *AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at 36-38. The working group should also discuss and implement any reasonable and cost-effective measures necessary to preserve CRES providers' communication channels with their CRES customers relative to programming initiated pursuant to market-based activities, and will further explore a reasonable and cost-effective solution for any potential limitations to CRES provider offered programs that could be impacted or limited due to physical or technology capabilities with smart thermostats and the vendors running the smart thermostat demand response

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[41] The adopted smart thermostat rebate program will be capped at $2,000,000, which is $1,456,539 less costly than the Demand Response for Residential program initially proposed by the Companies (Co. Ex. 5 at Attach. ECM-2).

operations, mitigating the concerns raised by RESA, IGS, and OELC (RESA/IGS Ex. 1 at 15; RESA Ex. 16 at 13-14; Tr. Vol. X at 1826-27).

{¶ 234} Finally, we address several recommendations made by Staff and others related to the Rider EEC mechanism. Initially, Staff suggests that the Companies only be allowed to recover expenses that are already incurred, known, and measurable, and should not be permitted to utilize projected expenses in the calculation of the rider (Tr. Vol. XIV at 2435-2436). Consistent with our findings pertaining to other riders, we agree that actual expenses would be more appropriate than utilizing projected expenses. Additionally, to the extent further clarification is needed, we agree with Staff's suggestion that only expenses incurred during the five-year approved term of the EE/PDR plan will be recoverable through Rider EEC. Further, Companies will not be authorized to accrue carrying charges for deferring recovery of expenses that could have been recovered in a prior EEC filing (Staff Ex. 8 at 23). We also agree with Staff that the annual Rider EEC filing should be docketed at least 60 days prior to its effective date, consistent with our adoption of this requirement for other rider mechanisms in ESP V (Staff Ex. 3 at 24). Further, consistent with our findings related to Riders SCR and VMC, we direct FirstEnergy to include the language "to the extent permitted by law" in the Rider EEC tariff language providing that Rider EEC be subject to reconciliation, including refunds, as the result of audits conducted by Staff. Finally, we adopt OCC's proposal to require competitive bidding for any outside implementation vendors, to ensure capable and cost-effective vendors are utilized for the duration of the approved programs.

{¶ 235} As modified by the Commission, the annual program budget for the EE/PDR plan should be $14,206,663 per year, compared to the $72.1 million annual budget proposed by the Companies (Co. Ex. 5 at ECM-2; Staff Ex. 3 at 4).[42] Accordingly, the

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[42] The total annual program budget for the EE/PDR plan can be broken up, as follows: $3,592,681 projected for Energy Education program, $8,613,982 for the Low-Income Energy Efficiency program, and $2,000,000 for the smart thermostat rebate program.

adopted EE/PDR plan is annually $57,921,552 less costly than that proposed by the Companies in its Application, or approximately $289,607,760 less costly over the adopted five-year term of ESP V. While OEC cautions against approving only a portion of the plan, we believe our decision is aligned with recently approved energy efficiency programs, and also takes into account programs that are appropriate in size and scale to allow the Companies to provide customers with energy efficiency and demand response services (Staff Ex. 3 at 5; Tr. Vol. IX at 1705, 1710; Tr. Vol. XIII at 2308).

O. Rider NMB

{¶ 236} Customers of the Companies currently pay for transmission through Rider NMB. Rider NMB is a pass-through, revenue-neutral mechanism designed to recover from FirstEnergy's customers the costs billed to FirstEnergy by the regional transmission organization, PJM, for transmission service, including Network Integration Transmission Service (NITS) and Regional Transmission Expansion Plan (RTEP) costs. Rider NMB is updated and reconciled annually, subject to review and approval by the Commission. Rider NMB was originally authorized in the Companies' ESP II and reauthorized, with modification, in ESP III and ESP IV. *ESP II Case*, Opinion and Order (Aug. 25, 2010); *ESP III Case*, Opinion and Order (July 18, 2012); *ESP IV Case*, Opinion and Order (Mar. 31, 2016). The rider is non-bypassable, except for a limited number of customers participating in a Rider NMB Transmission Pilot Program (NMB Pilot) (Co. Ex. 7 at 7-9). As part of ESP IV, the Commission approved the NMB Pilot, which was intended to explore whether certain customers could benefit from opting out of Rider NMB and obtain, directly or indirectly through a CRES provider, all transmission and ancillary services through PJM. *ESP IV Case*, Opinion and Order (Mar. 31, 2016), Fifth Entry on Rehearing (Oct. 12, 2016). PJM charges FirstEnergy for transmission based on specific costs known as Billing Line Items (BLI), allocating each one using one of several methodologies, including MWh, 1 Coincident Peak (CP) Net Service Peak Load (NSPL), or 12CP. In contrast, at the retail level, transmission costs that are not directly billed are allocated to each of the three Companies based on the

Company's previous month's load share (i.e., the percentage of MWh used by each of the three Companies). Each Company then allocates its share of transmission costs to its customer classes based on the most recent four summer peak months, calculating a demand allocation factor for each class. The demand and billing determinants for NMB Pilot customers must be removed when performing these allocations because they do not pay Rider NMB rates. Currently, the Companies use a 5CP methodology to remove NMB Pilot customers from Rider NMB. (Co. Ex. 6 at 10.) Under that approach, transmission costs are allocated to and recovered from NMB Pilot participants based upon the participant's demand during both the PJM ATSI zonal transmission critical peak and four additional FirstEnergy Ohio zonal transmission critical peak hours (hence, 5CP) in the preceding year. These 5CP hours comprise the customer's NSPL.

1. Rider NMB Rate Changes and Elimination of the NMB Pilot

{¶ 237} In its Application, FirstEnergy proposes to (1) continue, with modification, Rider NMB for the term of ESP V, as authorized by 4928.143(B)(2)(g) and (2) eliminate the NMB Pilot. Specifically, the Companies propose the creation of two different rate designs for commercial and industrial customers within Rider NMB. The first rate (NMB 1) will keep the current Rider NMB rate allocations and rate design. The second rate (NMB 2) will apply to commercial and industrial customers with an interval or advanced meter, and those customers will be billed based on their 5CP NSPL. (Co. Ex. 6 at 10.) During ESP V, if a customer on the NMB 1 rate receives a new interval or smart meter, the customer would then be switched immediately to NMB 2. The NMB 2 rate will be the same for all customers for all three Companies. Under the Companies' proposal, the NMB Pilot will end,[43] and

[43] Since all interval-metered or smart-metered commercial and industrial customers would be billed on an NSPL basis under the NMB 2 rate, there would no longer be a need for the NMB Pilot.

NMB Pilot customers will be moved to either NMB 1 or NMB 2, depending on the type of meter they use.

{¶ 238} According to the Companies, their proposal will result in rate design changes that will better align costs with cost causers and help customers better manage and control their transmission service charges. In fact, the Companies argue their proposal is supported with the recent report conducted by Exeter Associates (Exeter) in Case No. 22-391-EL-RDR, which concluded that there was an opportunity to improve cost causation in the treatment of non-market-based services costs (OELC Ex. 27).[44] Additionally, Exeter recommended eliminating Rider NMB, either for all customers or a subset of customers, and incorporating non-market-based services costs either through services obtained from a CRES provider for shopping customers or built into the SSO auction for non-shopping customers (*Id*. at 1-4). As such, the Companies believe their proposal will facilitate a better way to account for these costs, as recommended by Exeter. Additionally, the Companies assert that this approach is consistent with other transmission cost recovery mechanisms approved for other Ohio EDUs (OEG Ex. 1; OMAEG Ex. 2). *AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023) at 40.

{¶ 239} As noted above, the Companies propose to modify Rider NMB to include two separate rates, NMB 1 and NMB 2 (Co. Ex. 7 at 11, Attach. JL-4). Specifically, NMB 1 will be applicable to all residential and lighting customers, as well as commercial and industrial customers who do not have interval or advanced meters, and will be calculated using the current Rider NMB allocation and rate design, as well as continue to be charged on an energy or monthly peak demand basis. Additionally, NMB 2 will be applicable to commercial and industrial customers who have interval or advanced meters and will be charged based on a customer's NSPL. (Co. Ex. 7 at 10-11.) The Companies aver that these

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44 During the hearing, the ALJs also took administrative notice of the report completed by Exeter (Tr. VI at 1210). We reference the document as OELC Exhibit 27 or the Exeter Report throughout this Opinion and Order.

modifications are reasonable for several reasons. First, the Companies assert the proposed NMB 2 rate will better align non-market-based services costs with the cost causers, assigning costs in a manner consistent with the way PJM assigns most nonmarket-based services costs, i.e., by billing based on a customer's NSPL (Co. Ex. 7 at 10; Co. Ex. 10 at 11). FirstEnergy also notes that the NMB 2 rate will provide eligible customers with an opportunity to manage their costs by controlling their NSPLs, thereby lowering the overall costs assigned to the Companies (Co. Ex. 10 at 10-11). According to the Companies, all customers have similar opportunities to reduce their electric load during peak hours through a variety of available methods, including implementing behind-the-meter generation and investing in management practices and technologies (Tr. Vol. VII at 1549-1551; Tr. Vol. IX at 1744-1745). Third, the Companies note that the proposed NMB 2 rate design may also incentivize customers to reduce their overall usage during peak periods, which would support reliability on the Companies' distribution system, to the benefit of all customers. Finally, FirstEnergy claims that the NMB 2 rate will help enable customers to easily switch between shopping for generation and returning to the SSO without any impact to Rider NMB. As the Companies suggest making the proposed rate changes to Rider NMB effective April 1, 2025, they note that transition period will allow the Companies to develop and implement the necessary billing system changes and provide customers who currently have advanced or interval meters an opportunity to manage their NSPLs before the effective date (Tr. Vol. VI at 1239-1240).

{¶ 240} Relatedly, because the proposed Rider NMB 2 rate essentially replaces the current NMB Pilot program and applies to an expanded group of customers, the Companies assert that the NMB Pilot will no longer be needed in ESP V (Co. Ex. 7 at 8, 10). Accordingly, the Companies are proposing to eliminate the NMB Pilot, including applicable reasonable arrangements, effective April 1, 2025 (Co. Ex. 7 at 8). Additionally, the Companies cite to increased administrative burdens associated with overseeing the NMB Pilot, including the Commission directive to implement a manual billing system option. The Companies note these burdens will only increase as more participants are permitted to join the NMB Pilot.

(Tr. Vol. VI at 1227.) Due to these obstacles, FirstEnergy suggests that simply expanding the existing pilot program is not a feasible option at this time. By eliminating the current NMB Pilot and making the corresponding rate design changes discussed above, the Companies argue many of the current burdens associated with Rider NMB will be alleviated, including the manual billing option, as well as the need for the Companies to track NMB Pilot participants and their need to procure NMB services costs via CRES providers (Co. Ex. 7 at 10, 12).

{¶ 241} NRG, Nucor, and RESA support the modifications to Rider NMB and the replacement of the NMB Pilot with a new NMB 2 charge using NSPL as the billing determinant (Co. Ex. 7 at 12; RESA Ex. 15 at 5-7, Attach. EBS-1; OEG Ex. 1 at 5). Notably, these parties agree with FirstEnergy's assessment that the proposed changes will render a greater alignment between nonmarket-based services costs and cost causers and, thus, will promote cost causation principles (Co. Ex. 7 at 12; RESA Ex. 15 at 6-7; Nucor Ex. 1 at 19). RESA witness Rodriguez testified that another benefit of FirstEnergy's proposal is that it achieves transparent price signals through NSPL billing (which he alleges has a much better correlation to market fundamentals than NITS) without introducing a new risk premium that would be borne by customers, and such cost savings could later foster development of new market capacities for load management (RESA Ex. 15 at 7, 9). Nucor and RESA argue that Exeter recognized the value in the NMB Pilot and NSPL pricing to customers when it cited a resulting reduction in the Rider NMB revenue requirement in the amount of $231 million. Nucor adds that the Exeter report ultimately recommended that the Commission allow for NSPL pricing for all customers. (OELC Ex. 27 at 17, 50-52.)[45] RESA adds that, because the outcome of the NMB Pilot is to allow participants to be billed for transmission service on an NSPL basis, FirstEnergy's proposed modification to Rider NMB would achieve the outcome of the pilot program. Further, RESA notes that meaningful expansion of the

45 Exeter found that if the NMB Pilot had not existed during the review period (March 2017 to February 2023), the Rider NMB revenue requirement would have been $231,092,997 higher.

NMB Pilot is not a realistic possibility given the number of manual or nuanced processes associated with accommodating a customer in the existing program (Tr. Vol. VII at 1457-1459). OMAEG witness Schuessler testified that Rider NMB transmission charges are one of the single largest charges paid for by industrial customers, and allowing NMB Pilot participants to control their transmission costs through NSPL management could help lower such transmission costs, which will make the customer more competitive and cost-effective (OMAEG Ex. 2 at 5, 7). Relatedly, OMAEG and Nucor conclude that NSPL billing incentivizes customers to curtail their load during peak load periods, resulting in stability and improved reliability to the PJM grid and the ATSI zone (OMAEG Ex. 2 at 8; Nucor Ex. 1 at 19-20; OELC Ex. 32 at 10).

{¶ 242} While agreeing with the fundamental concept of FirstEnergy's proposal, Staff suggests that the Rider NMB proposal should be modified to more closely align with PJM's transmission cost allocations. To follow PJM's allocation, Staff recommends that any cost not directly billed should be allocated to each individual Company using the same methodologies that PJM uses (Staff Ex. 9 at 4-6).[46] Once costs have been allocated to each Company, Staff suggests that the Company allocate costs to each customer class, again based on the same allocation factors that PJM uses (Staff Ex. 9 at 6). Staff notes that these changes would apply to all costs flowing through Rider NMB and would ultimately serve to mitigate cost shifting among the Companies and their respective customer classes. Staff recognizes that the allocation changes will impact customer bills, but the magnitude of such changes remain unknown. Therefore, Staff recommends that the Commission require the Companies to provide bill impacts with compliance tariffs in this proceeding. If the bill impacts reveal unreasonable increases to customer bills, then Staff indicates that it may be necessary for the Commission to phase in the changes to the allocations over time to foster

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[46] While not basing transmission costs strictly on a NSPL basis, Staff recognizes that a substantial majority of PJM transmission charges are for NITS, which are charged based on NSPL, thereby indirectly satisfying some parties' desire to adopt transmission charges based on a customer's NSPL (Staff Ex. 9 at 6, 12-14; Tr. XIV at 2465-2468, 2479).

gradualism. Staff proposes these allocation changes for Rider NMB would not go into effect until April 2025, thus, allowing sufficient time to address bill impacts, if necessary, after compliance tariffs are filed. (Staff Ex. 9 at 6-7.)[47]

{¶ 243} Staff supports the Companies' proposal to eliminate the NMB Pilot, provided that certain modifications are made to the Companies' proposed NMB 2 rate. First, Staff argues that the Commission should reject the Companies' proposal for a single uniform rate for all commercial and industrial customer classes paying under NMB 2, as it would cause interclass and intraclass cost shifts. Instead, Staff witness Baas advocates that separate NMB 2 rates should be calculated for each Company and each customer class. (Staff Ex. 9 at 11-12.) Second, Staff suggests that the NMB 2 rate should be optional with an opt-in mechanism for customers in the GS class with smart or interval meters.[48] Third, Staff believes customers should not be immediately moved to the NMB 2 rate after installation of a new internal or smart meter; rather, the election should occur once a year in April at the time of the annual rider review. (Staff Ex. 9 at 13.) Fourth, given that bill impacts remain unknown, it is suggested that the Companies would need to work with Staff to review bill impacts that include actual NSPL data with the allocation changes compared to the current Rider NMB rates.[49] These bill impacts should be broken out by each EDU and customer class and should include customers that will be switching rates from the current NMB rates to NMB 2 rates. It should also include an analysis of customers switching rates from the

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47 RESA does not oppose Staff's modifications to the allocation process.

48 OELC urges the Commission to not adopt Staff's recommendation to proceed with the NMB 2 rate for FirstEnergy customers served at or above primary voltage, noting an accurate and vetted bill impact is necessary before any decision is made on whether this rate structure should be applied to all such customers that will not be given the option to remain on a monthly billing demand structure.

49 RESA supports Staff's request for an additional review; however, RESA recommends that the review begin well in advance of the annual Rider NMB update process so that all affected stakeholders have an opportunity to review and respond to any change in the implementation timeline proposed by FirstEnergy. Further, RESA contends that the Commission should clarify that the scope of the additional review is to address the implementation timeline and not revisit the structure of Rider NMB and whether it should be eliminated.

current NMB rates to NMB 1 rates. (Staff Ex. 9 at 12-13.) Finally, Staff would like to work with the Companies to structure the mechanics of the rider before the annual filing is made. Staff would agree with making the NMB 2 rate effective in April of 2025 after the annual review has been completed. If these five recommendations are adopted, and if allocations to each Company and customer class are modified to follow PJM allocations, Staff recommends eliminating the NMB Pilot at the time the new NMB 1 and NMB 2 rates take effect.

{¶ 244} In response, FirstEnergy raises several concerns regarding Staff's proposed modifications to the Rider NMB rate design and recommends that the Commission decline the modifications until an evaluation of various factors is undertaken. Namely, the Companies recommend considering (1) whether they have access to the data necessary to allocate transmission charges in accordance with all of the methodologies used by PJM, (2) whether their current billing system could accommodate the modifications, and (3) the estimated impact on customers' bills (Tr. Vol. XIV at 2504-2505, 2512). In addition, the Companies argue that customers could be confused using the different allocation methodologies used by PJM. Finally, FirstEnergy notes that Staff's proposal could enable customers to select, on a monthly basis, the lowest cost version of the NMB 1 or NMB 2 rate, thereby creating a shortfall that would effectively shift costs to other customers and increase the Companies' administrative burden (OEG 1 at 7).

{¶ 245} If Staff's five modifications regarding the NMB 2 rate are not adopted, however, Staff suggests that the NMB Pilot should continue and FirstEnergy's proposed NMB 2 rate should be rejected. Regardless of whether the NMB Pilot is continued, Staff contends that its allocation recommendations would still need to mirror PJM's allocation methodology to mitigate cost shifting going forward. If the NMB Pilot program remains, Staff recommends that it should be gradually extended and made available to all customers within the GS, GP, GSU, and GT rate classes. Additionally, Staff recommends participants' costs removed from Rider NMB should be changed to mirror PJM's allocation for each BLI, as it would eliminate the interclass and intraclass cost shifting currently caused by the program. (Staff Ex. 90 at 14.)

{¶ 246} IGS, OEG, and OELC contend that the Commission should adopt Staff's alternative proposal and permit the NMB Pilot to continue with the modified allocations described by Staff and reject NMB 2. OELC initially observes that only certain types of commercial and industrial customers have the operational flexibility to do this during potential 5CP events (OELC Ex. 32 at 12, 21-22). Thus, OELC argues that most commercial and industrial customers would not benefit from NSPL-based transmission billing. Without the requisite bill impact analysis, OEG asserts Staff's alternative proposal, i.e. maintaining the status quo for now and addressing bill impacts related to NSPL billing at a later time, should be adopted by the Commission (Tr. Vol. XIV at 2458-2463). While conceding that FirstEnergy's proposal is reasonable in concept, as it would create economic efficiency by sending correct price signals to these commercial and industrial customers and provide them with the opportunity to adjust their usage of the transmission system consistent with those prices, OEG and OELC note that Staff's initial recommendations were premised on the ability to have accurate bill impact information to support the rate modifications (OEG Ex. 1 at 5; Staff Ex. 9 at 14-15). OEG and OELC assert that the Companies' bill impact analysis is too flawed to be relied upon and should not be used to justify a significant rate change at this time. Specifically, OEG notes that FirstEnergy recognized at the hearing, its bill impact analysis: (1) compared current transmission rates to projected transmission rates in 2025 and 2026; (2) assumed that a customer's NSPL demand would be exactly equal to their monthly billing demand, despite the possibility that these numbers could vary by significant margins; and (3) modeled bill impacts on a total bill basis, rather than isolating impacts to reflect only the proposed transmission rate changes. Given these material errors, FirstEnergy's bill impacts cannot be relied upon to provide an accurate picture of the results of adopting their Rider NMB proposal (OELC Ex. 21; OELC Ex. 32 at 23; Staff Ex. 9 at 11; Tr. Vol. VI at 1195, 1198-1199, 1221-1224; Tr. Vol. XIV at 2455-2456). As such, OEG recommends that Staff's alternative proposal be adopted. IGS also agrees with Staff's alternative proposal, noting that, by expanding the NMB Pilot, customers are given the opportunity, but not the requirement, to take transmission on a bypassable basis (IGS Ex. 1 at 15-16). Citing to testimony from OELC witness Brakey, IGS and OELC also argue that NSPL-based billing for commercial and industrial customers will not be appropriate until FirstEnergy has finished installing advanced meters and recorded a summer of 5CP consumption (OELC Ex. 32 at 34, 37-38). Until that time, IGS and OELC recommend that the NMB Pilot be opened up to more customers that elect to proactively manage their load (OELC Ex. 32 at 38). Further, IGS raises concerns that FirstEnergy's proposal removes flexibility of a customer and CRES provider to establish transmission rates that fit that customer's individual needs and risk tolerances (IGS Ex. 1 at 16). Similar to OEG, IGS notes that FirstEnergy's proposal represents an improvement over the current billing mechanism; however, it should not be adopted at this time due to the stripping of customer choice. Instead, IGS argues the Commission could expand the NMB Pilot and ensure that customers opt in to negotiate the terms of their transmission rates with a CRES provider. This renders a more balanced approach without requiring CRES providers to accept additional costs that may not be included in their existing contracts. (IGS Ex. 1 at 16-17.)

{¶ 247} In addition to the concerns noted above, OELC goes further to suggest that FirstEnergy's proposed NMB 2 rate is discriminatory, unreasonable, and would result in dramatic rate shock for many customers. Recognizing that under the Companies' Rider NMB proposal only those commercial or industrial customers with an interval or advanced meter would be subject to the NMB 2 rate based on the customer's NSPL value, OELC contends that this may create an inconsistent approach for billing transmission costs among commercial and industrial customers within the Companies' service territories (Tr. Vol. V at 1109-1110; OELC Ex. 32 at 21, Attach. MB-3). Pointing to deployment statistics available at the time of hearing, OELC notes that FirstEnergy currently serves over 200,000 nonresidential customers and approximately two-thirds of those customers do not have advanced or interval meters; thus, these customers would be subjected to maintain monthly billing demand under the NMB 1 rate (OELC Ex. 32 at 6, 21, Attach. MB-3; Co. Ex. 7 at 7-8, 10-11; Tr. Vol. VI at 1194-1195). OELC also notes that it is uncertain when the other nonresidential customers would receive an interval or advanced meter, and thus be subject to the proposed NMB 2 rate, as the Companies did not provide that information in the Application or supporting testimony. Thus, similarly-situated customers would be treated disparately solely depending on the type of meter they utilized, effectively creating a "sub-class" of customers. Further, given the limited deployment of advanced or interval meters amongst FirstEnergy non-residential customers, OELC contends that the entire purpose of this billing change (i.e., aligning charges with transmission cost causation) would be lessened, since only a small portion of customers would be subject to NSPL billing for the foreseeable future (Tr. Vol. VI at 1215-1216). As an example of the drastic rate changes that could impact commercial and industrial customers, OELC relies on the testimony of Jeffrey Heinen, who provided testimony at the local public hearing in Akron on behalf of Heinen's, a Cleveland-based grocery store chain, stating that the NMB 2 proposal "will unfairly increase [Heinen's] utility bills" given all of its facilities currently use advanced meters. According to Heinen's calculations, the proposed NMB 2 rate would result in a $19,000 per month increase in its monthly utility bills, or a 49 percent increase in Rider NMB charges, culminating in additional costs of $228,000 annually and $1.8 million across FirstEnergy's proposed eight-year ESP V. Mr. Heinen testified that the grocer's only recourse would be to pass the additional costs on to its customers, which would further disadvantage it compared to its competitors, who may or may not have advanced or interval meters. (Akron Pub. Hearing Tr. at 21-23.) OELC adds that this type of disparate treatment and resulting rate shock will not only apply in a grocery store setting, but other types of customers, such as hospitals (OELC Ex. 32 at 31-33).

{¶ 248} OELC further asserts that, despite the inadequate bill impacts being provided in this proceeding, there is ample evidence to conclude that the NMB 2 rate will result in dramatic rate increases and significant rate shock, as "[c]ustomers that have an NSPL value that is higher than their average monthly billing demand will see increases in their transmission charges if they are billed the Rider NMB 2 based on their NSPL." (OELC

Ex. 32 at 30). Specifically, OELC notes that "[t]he bill impacts analyzing the NMB 2 rates show a range between a one percent decrease up to thirty nine percent increase on a customer's total bill." (Staff Ex. 9 at 10-11). OELC claims that its witness' analysis confirms Staff's assessment. In summary, witness Brakey's analysis shows that one sample of 50 commercial and industrial customers, which incorporated more than 20 different business industries or facility types, would see transmission cost increases ranging from 22 to 392 percent in monthly transmission charges if their accounts are switched to NSPL-based billing on the proposed NMB 2 rate (OELC Ex. 32 at 24-25). Additionally, witness Brakey prepared a corresponding analysis, which demonstrates that another sample of 50 commercial and industrial customers would see decreases to their Rider NMB transmission charges ranging from 47 to 87 percent (OELC Ex. 32 at 28-30). Again, OELC notes that the determining factor between these "winners and losers" under the NMB 2 rate was if a customer has an advanced or interval meter (OELC Ex. 32 at 32). As one specific example, OELC cites to testimony provided on behalf of the University of Akron during the Akron local public hearing in this proceeding, in which the representative indicated that the University estimates that the NMB 2 rate would increase its monthly transmission charges from $60,000 to $86,000 more per month, a roughly 43 percent increase. OELC notes that Akron participated in the NMB Pilot at one time but discovered that it ended up paying more under the NSPL-based billing and elected to leave the pilot program. (Akron Pub. Hearing Tr. at 14-19.) OELC represents that, while some customers benefited from choosing to participate in the NMB Pilot, there have been instances in which customers suffered increased costs under the NSPL-based billing model (OELC Ex. 27 at 10-12; OELC Ex. 32 at 31-33).

{¶ 249} Finally, OELC argues that another unreasonable aspect of FirstEnergy's proposed NMB 2 rate is its proposal to transition commercial and industrial customers with traditional meters to that NSPL-based rate in the billing month immediately following the month that an interval or advanced meter is installed at the customer's meter. OELC states that customers without interval or advanced meters will be assigned NSPL values based on "an artificial and administratively determined load profile" instead of their actual load during the ATSI 5CPs, as monthly-read meters are not sophisticated enough to capture time of use data. (OELC Ex. 32 at 34). Thus, until the interval or advanced meter is installed for a full summer (June 1 – September 30) in order to capture the customer's actual load during ATSI's 5CP hours, that customer's NSPL value will be derived by FirstEnergy based on load profiles which may vary significantly from actual NSPL values. (OELC Ex. 32 at 34-35; Tr. Vol. VII at 1541, 1548-1549.) OELC further asserts that customers with traditional meters will have no realistic opportunity to manage these artificially-derived NSPL values and would consequently subject customers to significant rate changes from month to month as FirstEnergy deploys interval or advanced meters (Staff Ex. 9 at 12; Tr. Vol. VI at 1195-1197). OELC also emphasizes that FirstEnergy is proposing to move forward without considering bill impacts before switching customers from monthly billing demand to NSPL billing, which Staff opposes (Staff Ex. 9 at 6-7).

{¶ 250} Summarily, OEG, OELC, IGS, and NRG agree the more prudent approach would be to expand transmission billing based on NSPL by opening up the NMB Pilot to more customers that have the means to manage their load during the ATSI zone 5CPs on an optional basis. OELC notes that this approach would also be consistent with the findings in Exeter's report, which calculated that the quantified benefits of the NMB Pilot outweighed its costs, with an estimated aggregate savings of over $230 million in transmission costs for all FirstEnergy customers over the six-year period from March 2017 through February 2023. OELC adds that the report also found NMB Pilot participants consistently reduced their load during anticipated 5CP events in the ATSI zone. By engaging in peak load shaving on a routine basis, the pilot participants "significantly contribut[ed] to lower overall system peaks during 5CP events, which translates into transmission savings for all FirstEnergy customers." In sum, the NMB Pilot produces a net positive for all FirstEnergy customers, and it should be maintained and expanded until such time as the deployment of interval or advanced meters in FirstEnergy service territory has reached a stage that could potentially allow a reasonable and non-arbitrary transition to NSPL-based billing for transmission charges in FirstEnergy's service territory. Moreover, OELC adds that, since Rider NMB is revenue-neutral, FirstEnergy would not be harmed by waiting to implement the proposed changes until all nonresidential customers receive advanced or interval meters and have an opportunity to have actual NSPL values assigned based on their consumption (Tr. Vol. VI at 1216-1217).

{¶ 251} Nucor ultimately suggests that the Commission should approve a mechanism that at least provides the option for commercial and industrial customers to choose NSPL pricing. Nucor notes that the opposition to FirstEnergy's proposal readily acknowledges the benefits associated with NSPL pricing. While Nucor agrees that the NMB 2 rate would be a reasonable mechanism, if the Commission rejects the Companies' proposal due to concerns related to bill impacts, Nucor would alternatively suggest that Commission should continue the existing NMB Pilot and open the program to all customers that would like to participate and possess the requisite type of meter.

{¶ 252} OCC argues that FirstEnergy's Rider NMB proposal is unjust and unreasonable because it improperly shifts transmission costs to the residential class and is contrary to Exeter's recommendation to eliminate the NMB Pilot, as it will be replaced with a new and expanded program. Contrary to the positions noted above, OCC argues that the Exeter report concluded that Rider NMB's cost allocation methodology shifts an additional one million dollars in transmission costs to residential consumers (OELC Ex. 27 at 18). OCC also echoes the concerns of Exeter related to the "shortcomings of Rider NMB in allocating certain PJM costs to nonparticipating customers based on the principle of cost causation." (OELC Ex. 27 at 3). OCC also notes that Exeter compared the NMB Pilot to a hypothetical scenario that assumed that no pilot program existed, which resulted in the $231 million difference in revenues cited by some of the advocates for continuing the pilot program. OCC stresses that, of that amount, $107 million in additional costs would have been assigned to consumers not participating in the NMB Pilot over that period, which Exeter characterizes as "a $107.7 million cost shift paid by non-participants over six years." OCC also notes that Exeter found that residential consumers received approximately 7.3 percent of the cost shifts for a total of $7.8 million in added costs, while non-participating large commercial and industrial consumers absorbed a cost shift of $57 million. (OELC Ex. 27 at 17, 26.) OCC agrees with these findings and support Exeter's initial conclusions that the NMB Pilot is "unlikely to provide direct reliability benefits" and "does not resolve the typical causes of grid stress" (OELC Ex. 27 at 4. 20, 39). Thus, OCC suggests that the Commission reject FirstEnergy's proposal by eliminating Rider NMB and the NMB Pilot and, instead, make Rider NMB bypassable, as discussed further below (OCC Ex. 1 at 40).

{¶ 253} Echoing many of the same arguments raised in the *AEP Ohio ESP V Case*, One Energy asserts the inclusion of Rider NMB in the Application on a non-bypassable basis violates Ohio law (Co. Ex. 1 at 11). *See AEP Ohio ESP V Case*, Opinion and Order (Apr. 3, 2024) at ¶¶39-40. Therefore, One Energy argues that the Application must be rejected by the Commission. Alternatively, One Energy argues that the Commission must require Rider NMB to be bypassable in order to comply with Ohio law, further noting that suppliers would be able to invoke "change in law/regulation provisions" in their contracts to address any issues that may arise as a result (Calpine Ex. 1 at 5). OCC and Calpine agree that transmission should be made bypassable, citing Exeter's recommendation to move all transmission costs to CRES providers as support (OCC Ex. 1 at 40; Calpine Ex. 1 at 3-8; OELC Ex. 27 at 50; Tr. Vol. IV at 746; Tr. Vol. X at 1862-1863). Calpine notes the urgency to foster the competitive market and require all CRES providers to be directly billed from PJM, taking responsibility for all of their wholesale market transmission costs and all associated billing. Calpine states that Exeter's recommendation to make transmission costs bypassable recognizes that there is not a "one-size-fits-all" approach and that customer choice will be enhanced if CRES providers are directly billed from PJM.

{¶ 254} In response, IGS, RESA, OELC OEG, and NRG argue that making Rider NMB bypassable would unjustly and unreasonably add costs that suppliers do not have embedded in their retail contracts, ultimately harming the competitive market. Among other things, they cite to IGS witness Poprocki's and OMAEG witness Schussler's testimony, in which they stated that making transmission costs bypassable would cause chaos in the retail market as existing contracts include transmission rates, which likely would cause legal disputes between CRES providers and their customers. (IGS Ex. 1 at 16; OMAEG Ex. 2 at 11-12; Tr. Vol. VI at 1267-1268; Tr. Vol. X at 1868-1870.) OELC also contends that Calpine and OCC's reliance on the Exeter report is misplaced, as the report's conclusion regarding cost-shifting was based on the faulty "no load reduction" assumption in its counterfactual analysis without any further explanation, despite acknowledging that the evidence demonstrated NMB Pilot participants altered their load on a consistent basis (OELC Ex. 32 at 18). Further, OEG, OELC, and IGS note that OCC, Calpine, and One Energy have provided no bill impact analyses that capture the potential impact of their recommendation to make Rider NMB bypassable. OEG and RESA also raise concerns for SSO suppliers with this approach, as shifting transmission billing to suppliers might only increase the risk premiums currently observed in SSO pricing (OEG Ex. 1 at 10). Instead, OEG, NRG, and IGS advocate for the expansion of the NMB Pilot to make it available to all customers so that customers can have the benefit of enhanced transmission rates without potentially disrupting the competitive market. Further, IGS and Staff add that, to the extent necessary, the Commission maintains the authority to waive any requirement in Ohio Adm.Code Chapter 4901:1-36-04(B). *See, e.g., In re The Dayton Power and Light Co.*, Case No. 08-1094-EL-SSO, Third Entry on Rehearing (Dec. 14, 2016); *In re the Application of Ohio Power Co.*, Case No. 12-1046-EL-RDR, Finding and Order (Oct. 24, 2012) at ¶14. Similarly, RESA opposes moving transmission cost responsibility for all customers to the CRES providers, explaining that residential customers lack the requisite knowledge and means to negotiate transmission service in their contracts (RESA Ex. 15 at 8-9).

2. UNACCOUNTED FOR ENERGY AND RESETTLEMENT PROPOSAL

{¶ 255} As one final modification to Rider NMB, the Companies propose to change the risks for customers and simplify the settlement process. According to FirstEnergy witness Stein, several factors can contribute to UFE, including estimated versus actual customer hourly load data, estimated versus actual losses, unmetered usage, and other errors/estimates in meter data. (Co. Ex. 10 at 8.) Currently, the Companies allocate UFE to customers' load, and subsequently to responsible load serving entities (LSEs), based on a load-ratio share on an hourly basis. For ESP V, the Companies are proposing to stop allocating UFE to all LSEs, and, instead, the Companies would retain all UFE and include the costs as a charge or credit in Rider NMB. The Companies allege that their proposal would simplify the allocation of UFE, improving transparency of these costs for customers. (Co. Ex. 10 at 8-9.) Additionally, FirstEnergy claims that including UFE in Rider NMB will make it easier for the Companies to remediate retail billing errors, as such errors will no longer be spread across all suppliers. Consequently, allege the Companies, this will lead to more efficient and quicker market resettlements, adding that their proposal includes adding a provision to the supplier tariff that obligates all suppliers to agree to resettlement. (Co. Ex. 10 at 9; Attach. EBS-1.) Similar to the benefits of the other recommended changes to Rider NMB, FirstEnergy notes that allocating UFE as proposed will also better align the Companies' approach with PJM billing for meter error corrections, the PJM line item where UFE is reconciled in the PJM billing process, which is already included as a non-market-based service in Rider NMB (Co. Ex. 10 at 8-9). Further, the Companies assert their proposal may result in lower costs for customers, as suppliers would no longer be responsible for UFE and, therefore, would no longer need to account for UFE in the SSO auction process or their competitive retail pricing (Co. Ex. 10 at 9). Notably, the Companies' proposed allocation method has been used successfully by the Companies' affiliates in other jurisdictions and will not result in any additional costs to customers (Co. Ex. 10 at 9).

{¶ 256} RESA agrees fundamentally with the Companies' proposal but does express concerns regarding the resettlement portion and requests certain modifications be made in the event the Commission adopts the proposal. RESA acknowledges that there are significant barriers to addressing billing errors and market resettlements, noting that FirstEnergy is currently required to approach all LSEs in its zone, approximately 140 entities, to fix incorrect bills. Moreover, if the bill error is not discovered within 60 days, then resettlement under PJM's rules is voluntary. Moreover, even if all suppliers agree, RESA claims there is still a complex process to correct the UFE allocations (an allocation unique to every hour). RESA agrees with FirstEnergy that the proposal to move PJM line item responsibility for UFE to Rider NMB will foster transparency, explaining that UFE charges "are non-market based which inherently makes them very difficult for SSO Suppliers and CRES providers to predict and manage. If SSO Suppliers and CRES providers, rather than EDUs, are responsible for these unknown and unpredictable costs, then in order to account for such risk, all suppliers need to factor a premium into their offers. Suppliers have to consider the potential costs that they could incur." (RESA Ex. 15 at 5; Tr. Vol. XIV at 2470). However, RESA recommends that there be a temporal limitation on how much time suppliers have to agree to resettlement, as FirstEnergy's proposal currently places no such limitation on the length of time resettlement could be required (Tr. Vol. VII at 1420). RESA proposes that CRES providers only be required to consent to resettlement for 12 months from the time of relevant service to the customer, arguing this deadline balances the needs of suppliers for billing finality and the ability to remedy prior billing errors. RESA also recommends that the Commission add clarification to the resettlement language FirstEnergy proposes to ensure that CRES providers are only required to agree to mandatory resettlement with others that have a reciprocal mandatory resettlement obligation.[50] Finally, while RESA would be agreeable to consenting to the resettlement process, the language FirstEnergy proposes needs clarified to ensure that CRES providers still have an opportunity to dispute FirstEnergy's calculation of the amounts to be resettled.

{¶ 257} Staff recommends that the Commission maintain the status quo and not adopt the Companies' proposal at this time. Noting the concern to have to mathematically derive customer hourly load data in the absence of a smart meter, Staff suggests that it would be more appropriate for the Commission to consider this proposed change to UFE in

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50 For example, RESA notes that FirstEnergy is in charge of reporting load of municipalities and rural co-ops in its zone to PJM, and Mr. Stein believes in their interconnection agreements there would be a resettlement requirement (Tr. VII at 1417-1420). However, there is no evidence in the record confirming this is correct with respect to all third parties.

a future case when FirstEnergy has completed, or is closer to completing, its smart meter rollout. Further, Staff claims no other Ohio utility addresses UFE in the way that FirstEnergy proposes, which further supports maintaining the current process for now. (Staff Ex. 10 at 15.)

{¶ 258} In response to Staff, RESA asserts that, while UFE might be lower in future years, the proposed UFE change will assist FirstEnergy in correcting billing issues. RESA also notes that Staff fails to address other aspects of the proposal, including the possibility of lower overall costs to customers due to the elimination of risk premiums included in market offers that would otherwise have to include this nonmarket-based cost in their supply offers. Further, RESA opines that, while FirstEnergy might be the first Ohio EDU to implement this change, that alone does not mean the change is unreasonable. RESA urges the Commission to adopt the Companies' UFE changes, as modified by RESA.

{¶ 259} Many parties and Staff provided the Commission with thoughtful recommendations to continue to reform Rider NMB in order to address a variety of issues, including cost shifting among the FirstEnergy EDUs and customer classes. Nonetheless, the Commission finds that the weight of the evidence in the record does not support any modification to the current Rider NMB. We agree with OEG that there is a distinct lack of evidence regarding the bill impact of the proposed modifications to Rider NMB. We are unwilling to adopt modifications to Rider NMB until parties can demonstrate how classes of customers and individual customers are impacted by the proposed change.

{¶ 260} In addition, we are mindful of the testimony of IGS witness Poprocki and OMAEG witness Schussler's testimony that elimination of Rider NMB and return to the paradigm where load serving entities provide transmission service has the potential to disrupt the CRES market as existing contracts likely do not include the costs of the non-market-based transmission services currently obtained through Rider NMB (IGS Ex. 1 at 16; OMAEG Ex. 2 at 11-12; Tr. Vol. VI at 1267-1268; Tr. Vol. X at 1868-1870). Accordingly, the Commission will modify the proposed ESP to continue, without any changes proposed by various parties, Rider NMB in its current form. This includes rejecting the Companies' proposal to modify the allocation and assignment of UFE.

{¶ 261} Further, we will continue the Rider NMB Pilot Program through the five-year term of the ESP. The Exeter Report demonstrates that the Rider NMB Pilot Program better aligns costs with cost causation, consistent with sound ratemaking principles (OELC Ex. 27 at 3, 18, 41, 43). Further, the Exeter Report demonstrates that the Rider NMB Pilot Program saved FirstEnergy customers, in the aggregate, over $231 million during the audit period between March 2017 through February 2023 (OELC Ex. 27 at 17).

{¶ 262} In addition, the Commission finds that the evidence supports a modest expansion to the Rider NMB Pilot Program. Accordingly, we direct the Companies to open up the program for new customers with an aggregate load not to exceed 100 MW on a first-come, first-served basis, beginning June 1, 2024, with each individual new participant capped at 20 MW. The Commission notes that, regardless of this 100 MW expansion for eligible customers, additional customers may seek approval to enroll in the Rider NMB Pilot Program by filing an application for a reasonable arrangement pursuant to R.C. 4905.31.

P. MFA Test

{¶ 263} R.C. 4928.143(C)(1) provides that the Commission shall approve, or modify and approve, an application for an ESP if it finds that the ESP 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 (MFA Test).

{¶ 264} The Companies assert that ESP V provides significant qualitative and quantitative benefits that would not be realized under an MRO, so the Commission should find ESP V more favorable in the aggregate than an MRO. FirstEnergy represents that the benefits of ESP V include the EE/PDR plan, stewardship initiatives, and distribution riders (Co. Ex. 2 at 12-13). As for the EE/PDR plan, the Companies state that the programs result in net benefits to customers between $139 million and $534 million (Co. Ex. 2 at 12). The Companies explain that energy efficiency programs are exclusive to ESPs, as they are authorized by R.C. 4928.143(B)(2). As for the stewardship initiatives, FirstEnergy states that it has committed $52 million of shareholder funds, in part to support low-income customers, which would not be offered as part of an MRO (Co. Ex. 2 at 12). FirstEnergy also explains that distribution Riders DCR, AMI, SCR, and VMC will provide qualitative benefits to customers by providing efficient and cost-effective means to support the distribution system (Co. Ex. 2 at 13). Specifically, FirstEnergy states that these riders reduce regulatory lag, thereby incentivizing a proactive approach to prioritize reliability, citing *Duke ESP IV Case*, Opinion and Order (Dec. 19, 2018) at ¶ 290. FirstEnergy adds that the distribution riders are subject to regular update and reconciliation, which promotes gradual rate impacts for customers, as even acknowledged by OCC Witness Collins (Tr. Vol. XIV at 2610; Tr. Vol. XIII at 2223-24).

{¶ 265} Staff agrees that ESP V, with Staff's recommendations, is more favorable in the aggregate than an MRO. Staff explains a quantitative benefit of the ESP is the shareholder-funded programs that benefit customers (Staff Ex. 1 at 4). As for qualitative benefits, Staff points out that the ESP includes low-income assistance programs, limits bill impacts, and establishes riders with annual audits for accountability (Staff Ex. 1 at 15-18). OPAE adds that the ESP is more favorable than an MRO because of the weatherization and bill payment assistance programs (Staff Ex. 1 at 4).

{¶ 266} In response, Kroger and OMAEG dispute the assertion that the EE/PDR programs make the ESP more favorable because the law no longer allows mandatory EE/PDR programs. Kroger adds that the Commission has determined that such programs should be limited to low-income customers. Because Kroger deems this program to be unlawful, it asserts the program should not be considered in the ESP v. MRO analysis. OCC argues that, even with Staff's recommendations, the ESP would still be less favorable than an MRO.

{¶ 267} OCC, NOAC, Kroger, and OMAEG assert that the ESP is not more favorable in the aggregate than an MRO. OCC explains that the Commission typically looks at three elements when determining whether the ESP or MRO would be more favorable: the SSO price, quantifiable provisions, and qualitative provisions, citing *In re the Application of Columbus Southern Power Co. and Ohio Power Co. for Authority to Establish a Standard Service Offer*, Case No. 11-346-EL-SSO, et al., Opinion and Order (Aug. 8, 2012) at 73. OMAEG emphasizes that FirstEnergy has the burden to demonstrate that its ESP is more favorable than an MRO, citing R.C. 4928.143(C)(1). OMAEG highlights that the benefits of the ESP are estimates without record support, as FirstEnergy's analysis did not consider the effects of the 2024 rate case (Co. Ex. 2 at 12-13; Co. Ex. 4 at 4-5; Co. Ex. 7 at 6, 11-13; Tr. Vol. III at 617; Tr. Vol. VI at 1280-81).

{¶ 268} OCC, Kroger, and OMAEG assert that FirstEnergy's approach fails to consider the areas where the ESP would be less favorable than an MRO. The parties assert that the ESP utilizes a stale ROE, which the parties argue is too high (Tr. Vol. I at 148). Kroger disputes FirstEnergy's assertion that the cost of SSO service would be the same under the ESP or an MRO because that analysis does not take into consideration Riders DCR, VMC, and SCR, which would involve above-market charges without the protections of a base rate case. Kroger and OMAEG add that the ESP riders allow the Companies to recover their expenditures and earn a return immediately, even if the assets are later disallowed. Additionally, OMAEG notes that if the costs were recovered in a base rate case, the costs would be subject to a more transparent review that would ensure the costs are used and useful. OMAEG argues that FirstEnergy did not calculate the costs associated with Riders DCR, AMI, SCR, and VMC (Tr. Vol. I at 143; Tr. Vol. II at 436; Co. Ex. 2 at 13). OMAEG questions whether revenue caps on various riders provide a real benefit, as they are too high and allow rollover into future years (OMAEG Ex. 1 at 15; OCC Ex. 1 at 13, 26, 28; Kroger Ex. 1 at 5-6; Staff Ex. 10 at 28-31; Staff Ex. 1 at 6; Staff Ex. 4 at 3-5; Staff Ex. 8 at 5). While Riders DCR, SCR, AMI, and VMC support the distribution system, OMAEG asserts that the same investments could be made and recovered through base rates with an MRO

(Tr. Vol. I at 101, 143; Tr. Vol. II at 436; Co. Ex. 2 at 12-13). OCC also argues that the ESP allows FirstEnergy to collect transmission-related costs through Rider DCR; fails to include a depreciation offset in Riders DCR and AMI; Rider VMC fails to flow cost savings through to customers; and the ESP would continue Rider NMB, which OCC says results in cost shifting.

{¶ 269} As to quantitative benefits, estimated by FirstEnergy to be between $191 - $576 million, OMAEG and Kroger contend that amount falls short in comparison to the costs for Rider DCR alone. Looking to the $52 million shareholder commitment, OMAEG submits that nothing would preclude the companies from making the same $52 million commitment through an MRO (Tr. Vol. I at 99-100). OMAEG and Kroger question whether the $52 million will be fully utilized, as only $2.1 million of a $24 million commitment has been spent as part of ESP IV (Tr. Vol. V at 977). OCC notes that ESP V and associated riders would add $6.2 billion in new charges without corresponding benefits.

{¶ 270} Lodging additional challenges at the ESP proposal, OMAEG takes issue with Company testimony that estimated revenues of $35.245 billion could differ based on the outcome of the rate case, the *Grid Mod II Case*, and whether the Companies meet reliability metrics (Co. Ex. 2 at Attach. SFL-3; Tr. Vol. I at 79). Additionally, OCC alleges that the ESP would violate R.C. 4928.143(C) because customers in years five through eight of ESP V would be required to pay for programs in which they cannot participate, citing R.C. 4928.143(C), which requires the benefits derived from a surcharge be available to those that bear the surcharge.

{¶ 271} FirstEnergy counters these assertions by noting that there is no authority outside of an ESP to implement EE/PDR programs, and that program as part of ESP V will result in net benefits for all customers (Tr. Vol. XIII at 2246; Co. Ex. 1 at 8-9). As to the assertion that the Companies could offer the $52 million stewardship initiatives in an MRO, FirstEnergy declares that it would not do so (Tr. Vol. I at 99). Challenging the argument that the distribution riders cause ESP V to fail the MFA Test, FirstEnergy points out that

Commission precedent demonstrates that "costs of [distribution] riders are equal under an MRO," as affirmed by the Ohio Supreme Court, citing *Duke ESP IV Case*, Opinion and Order (Dec. 19, 2018) at ¶ 290; *In re Application of Ohio Edison Co.*, 146 Ohio St.3d 222, 2016-Ohio-3021, 54 N.E.3d 1218, ¶¶ 23-27. The Companies conclude that the distribution rider costs are equal under an ESP or MRO. The Companies also dispute arguments that individual provisions of ESP V make it less favorable than the MRO, noting that the Commission must consider the ESP in the aggregate, citing R.C. 4928.143(C)(1). Staff adds that the parties generally critique FirstEnergy's proposal itself rather than with the modifications Staff recommends, which Staff represents will then be more favorable in the aggregate than an MRO.

{¶ 272} The Commission finds that the evidence in the record demonstrates that the proposed ESP, as modified by the Commission above, is more favorable in the aggregate than the expected results of an MRO. In conducting the MFA test, the Commission will look at the *relative price* to be paid by SSO customers for generation service under both the proposed ESP and a hypothetical MRO, whether there are *quantitative benefits* to the ESP that would not exist in an MRO, and whether there are *qualitative benefits* to the ESP that would not exist in an MRO. *AES Ohio ESP IV Case*, Opinion and Order (Aug. 23, 2023) at ¶ 208. In considering each of these factors in this case, the Commission finds that the proposed ESP, as modified by the Commission, meets the MFA Test.

{¶ 273} In examining the *relative price* between the proposed ESP and a hypothetical MRO, the Commission notes that, under the proposed ESP, the rates to be charged SSO customers will be established through a CBP which is similar to, if not identical with, the CBP under an MRO. Further, we agree with the testimony of Staff witness Messenger, who testified that distribution riders that are created or included in the ESP, including but not limited to Rider DCR, Rider VMC, and Rider SCR, do not add costs to the ESP as compared to the MRO because the costs are recovered through those riders would be subject to recovery in a base distribution rate case under an MRO (Staff Ex. 1 at 4). This is consistent with our finding in prior ESPs proposed by FirstEnergy as well as the other EDUs in this state. *ESP III Case*, Opinion and Order (July 18, 2012) at 56. *AES Ohio ESP IV Case*, Opinion and Order (Aug. 9, 2023) at ¶ 214.

{¶ 274} With respect to *quantitative* benefits, the Commission notes that, as modified, the ESP will provide for a commitment of $32.5 million in shareholder funds to be used for the benefit of ratepayers (Staff Ex. 1 at 4). Specifically, the Companies shareholders will fund programs for bill assistance, to establish a senior citizen discount, and to promote EV charging. Although OMAEG speculates that nothing precludes the Companies from making the shareholder funding available under an MRO, OMAEG offers no evidence that the Companies would do so, and the Companies flatly reject that possibility. OMAEG and Kroger also claim that this commitment may be illusory based upon experience with the Companies under ESP IV; however, we have imposed annual reporting requirements, as discussed above, to ensure the timely expenditure of shareholder funds under this commitment. Accordingly, we find that these programs represent a $32.5 million quantitative benefit for the ESP over an MRO. In addition, the evidence demonstrates that the Rider NMB Pilot program saved ratepayers, in the aggregate, over $231 million during the audit period between March 2017 through February 2023 (OELC Ex. 27 at 17). These aggregate savings will continue into the future and should be considered a quantitative benefit of the ESP.

{¶ 275} The Commission finds that the proposed ESP, as modified by Staff's recommendations, provides *qualitative* benefits, which are directly related to the policies of the state, as codified in R.C. 4928.02. As noted above, it is the policy of this state to ensure the availability of reliable retail electric service. R.C. 4928.02(A). The provisions of ESP V are targeted to maintaining and improving the reliability of distribution service. Rider DCR provides for the accelerated recovery of distribution investments intended to promote reliability; pursuant to the recommendation of Staff, adopted above, only plant investments directly related to maintain reliability will be recovered through Rider DCR (Staff Ex. 10 at 9; Staff Ex. 8 at 7-8). Rider VMC should promote reliability by providing for the recovery of incremental vegetation management expenses compared to the baseline currently in rates.

Under the revised caps proposed by Staff, the Companies will only recover the estimated costs for completing the minimum regulatory work during the term of ESP V. (Staff Ex. 1 at 5, 7.) Rider SCR, as modified by the Commission, will facilitate the timely recovery of storm damage expenses resulting from "major events" and , thus, encourage the Companies to restore electric service as soon as possible, which will also promote reliability.

{¶ 276} Moreover, the Commission finds that the provisions of Rider ELR, as modified, are a qualitative benefit of this ESP. Rider ELR maintains a critical program that supports both reliability and economic development (Staff Ex. 10 at 16-17, 25-26, Tr. Vol. XIV at 2571-72, 2589-91). The ESP, as modified, strikes the appropriate balance between maintaining this critical program and reducing the bill impact upon other customers. Further, the provisions regarding Rider ELR support state policies promoting "reasonably priced retail electric service" and "the state's effectiveness in the global economy." R.C. 4928.02(A), (N).

{¶ 277} In addition, we find that the provisions of the ESP, as modified, regarding energy efficiency programs provide a qualitative benefit for the ESP. As modified by the Commission above, the funding for energy efficiency programs, to be recovered from ratepayers, will be reduced from a proposed $72.2 million per year for four years to $14.2 million per year for five years, and over sixty percent of the funds will be used for low-income customer programs. The provisions of the ESP, as modified, strike the balance between providing funding for energy efficiency programs for low-income customers and minimizing the bill impact upon other customers. Thus, we find that the energy efficiency programs, as modified, are consistent with state policy to protect at-risk populations. R.C. 4928.02(L).

{¶ 278} Further, as modified, the energy efficiency programs will provide a smart thermostat rebate program which will provide customers with the ability to manage their load and will encourage the competitive market to deliver innovative products to consumers (Tr. Vol. IX at 1717-1718; Tr. Vol. X at 1801-12, 1818, 1825-27, 1841-42). This is also consistent with state policy, particularly, the policy to ensure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs and to encourage innovation and market access for cost-effective supply- and demand-side retail electric service. R.C. 4928.02(B), (D).

{¶ 279} Moreover, we find that provisions of ESP V, specifically Rider DCR, Rider SCR, and Rider VMC, promote gradualism by providing for smaller annual increases in the riders rather than a larger increase in rates following a distribution rate case (Staff Ex. 10 at 6-7). The evidence in the record also demonstrates that the Rider NMB Pilot Program better aligns costs with cost causation, consistent with sound ratemaking principles (OELC Ex. 27 at 3, 18, 41, 43). Thus, we conclude that the promotion of gradualism and the alignment of costs with cost causation are qualitative benefits of the ESP.

{¶ 280} We also note that several parties claim that FirstEnergy has an excessive number of riders; the Companies propose to discontinue 18 riders as part of the ESP (Tr. XIII at 2217). Thus, we find that the elimination of these riders is a qualitative benefit under the ESP.

{¶ 281} Moreover, the Commission finds that claims that ESP V fails the MFA Test lack merit. By focusing on the alleged costs to be recovered under Rider DCR, OCC, OMAEG and Kroger repeat an argument against Rider DCR that has been rejected by the Supreme Court of Ohio. *In re Application of Ohio Edison Co.,* 2016-Ohio-3021 at ¶ 25 (holding that, unlike an MRO, an ESP will include various cost-recovery mechanisms at the outset; therefore, an MRO will always appear to be quantitively more favorable but will never reflect the true cost of the MRO over time). Kroger's contention that Riders DCR, VMC, and SCR involve above-market charges is nonsensical; there are no "above market" charges for distribution services because distribution service is a non-competitive retail electric service under Ohio law. R.C. 4928.01(A)(22) and (27); R.C. 4928.01(B).

{¶ 282} Moreover, OCC's claims regarding the total cost of the ESP fail to consider the modifications to the ESP recommended by Staff and the impact of those modifications upon the total revenue requirement of the proposed ESP; OCC witness Collins conceded that he had not performed an MFA Test regarding the ESP as proposed to be modified by Staff (Tr. Vol. XIII at 2251-2252). Likewise, OMAEG and Kroger's assessment regarding the alleged cost of Rider DCR and its impact on the MFA fails to take into account the reductions in recovery under Rider DCR recommended by Staff (Staff Ex. 10 at 7-10) and adopted by the Commission above. This modification will substantially reduce the cumulative projected cost of Rider DCR (Staff Ex. 8 at 5).

{¶ 283} Further, the Commission noted that the costs of the proposed ESP V, as calculated by OCC and OMAEG, understandably do not take into account the additional modifications to the proposed ESP ordered by the Commission. In addition to the substantial reductions to Rider DCR recommended by Staff and adopted by the Commission, the Commission has modified the ESP to reduce the cost of the energy efficiency programs from $72 million per year for four years to $14.2 million per year for five years. The Commission also reduced the cumulative approved caps for Rider VMC from the Companies proposal with new caps to be addressed in FirstEnergy's upcoming rate case (Staff Ex. 1 at 5-6). Thus, we find that the projections in the costs of ESP V provided by OCC, OMAEG and Kroger are of minimal probative value in the MFA Test because these projections were not able to take into account the significant reductions in the cost of ESP V resulting from the modifications ordered by the Commission.

{¶ 284} Accordingly, as discussed in detail above, the Commission finds that, having considered the relative price of the ESP versus a hypothetical MRO, the qualitative benefits of the proposed ESP and the quantitative benefits of the proposed ESP, the evidence in the record demonstrates that, as modified by the Commission, the proposed ESP, 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 R.C. 4928.142.

IV. FINDINGS OF FACT AND CONCLUSIONS OF LAW

{¶ 285} FirstEnergy is a public utility as defined in R.C. 4905.02 and an EDU as defined in R.C. 4928.01(A)(6), and, as such, is subject to the jurisdiction of this Commission.

{¶ 286} On April 5, 2023, FirstEnergy filed an Application for an SSO pursuant to R.C. 4928.141. The Application is for an ESP in accordance with R.C. 4928.143.

{¶ 287} On May 10, 2023, a technical conference was held regarding FirstEnergy's ESP Application.

{¶ 288} The following parties were granted intervention in these proceedings: OELC, OEG, NOPEC, OPAE, OCC, Calpine, IGS, CC, UFA, NOAC, OMAEG, Walmart, Nucor, Utility Workers Union of America Local 126, One Energy, Constellation, OHA, Armada, Nationwide Energy Partners, Kroger, CUB, ELPC, RESA, Enel North America Inc., OEC, Utica East Ohio Midstream LLC, and NRG.

{¶ 289} On various dates in September 2023, three public hearings were held – in Cleveland, Toledo, and Akron.

{¶ 290} The evidentiary hearing in these proceedings commenced on November 7, 2023, and concluded on December 6, 2023.

{¶ 291} Initial briefs were filed on January 19, 2024. Reply briefs were filed on February 9, 2024.

{¶ 292} The Commission notes that the riders continued under this ESP are cost-based, reconcilable, and subject to refund based upon audits to be performed by, or at the direction of, Staff.

{¶ 293} Based upon the evidence in the record of this proceeding, the Commission finds, as discussed above, that the proposed ESP V should be modified and approved by the Commission. We will clarify that the proposed ESP is approved, subject to the recommendations by Staff, except for those recommendations which the Commission expressly declined to accept or otherwise explicitly modified.

{¶ 294} FirstEnergy is directed to file final tariffs consistent with this Opinion and Order, subject to final review by the Commission.

V. ORDER

{¶ 295} It is, therefore,

{¶ 296} ORDERED, That FirstEnergy's Application be approved, as modified by Staff's recommendations and this Opinion and Order. It is, further,

{¶ 297} ORDERED, That FirstEnergy file proposed tariffs consistent with this Opinion and Order, subject to final review by the Commission. It is, further,

{¶ 298} ORDERED, That the December 6, 2023 motion for a limited stay of the proceedings be denied. It is, further,

{¶ 299} ORDERED, That RESA's motion to strike be denied. It is, further,

{¶ 300} ORDERED, that Calpine's motion for leave to file its post-hearing brief instanter be granted. It is, further,

{¶ 301} ORDERED, That a copy of this Opinion and Order be served upon all interested persons of record.

COMMISSIONERS:
Approving:
Jenifer French, Chair
Daniel R. Conway
Lawrence K. Friedeman
Dennis P. Deters
John D. Williams

MJA/JWS/GAP/mef