139 FERC ¶ 61,068
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

PJM Interconnection, L.L.C., Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc.	Docket Nos. ER12-91-000 ER12-91-002 ER12-92-002

ORDER ON PROPOSED TARIFF REVISIONS AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued April 24, 2012)

1. On October 14, 2011, pursuant to section 205 of the Federal Power Act (FPA),[1] PJM Interconnection, L.L.C. (PJM), Duke Energy Ohio, Inc. (Duke Ohio) and Duke Energy Kentucky, Inc. (Duke Kentucky) (jointly, the Companies) (all, collectively, Filing Parties) jointly submitted modifications to the PJM Open Access Transmission Tariff (OATT), the Amended and Restated Operating Agreement (OA), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (RAA) and the Consolidated Transmission Owners Agreement (TOA) in connection with the Companies' integration into PJM.[2] On April 5, 2012, pursuant to Rule 602 of the Commission's rules of Practice and procedure,[3] the Companies submitted a settlement agreement (Settlement Agreement) that resolves all issues between the Companies and Indiana Municipal Power Agency (IMPA).

2. As discussed below, the Commission (a) approves the Settlement Agreement between the Companies and IMPA, (b) rejects in part, and accepts in part the proposed

[1] 16 U.S.C. § 824d (2006).

[2] On December 29, 2011 and February 24, 2012, the Companies submitted Tariff amendments in order to pursue settlement discussions.

[3] 18 C.F.R. § 385.602 (2011).

modifications to the Tariff, suspends them for a nominal period to be effective January 1, 2012, subject to refund, subject to a compliance filing and a refund report, and (c) establishes in Docket No. ER12-91-000 hearing and settlement judge proceedings under section 206 of the Federal Power Act with respect to the Companies' return on equity.[4]

I. Background

3. On June 25, 2010, the Companies submitted a filing in Docket No. ER10-1562-000 as the first step of their proposed move from the Midwest Independent Transmission System Operator, Inc. (MISO) Regional Transmission Organization (RTO) to the PJM RTO, effective January 1, 2012. Subject to specified conditions, the Commission authorized the Companies to join PJM in an order issued October 21, 2010.[5] The October 21 Order anticipated future filings to effectuate the transition into PJM.

4. Duke Ohio and Duke Kentucky are wholly owned subsidiaries of Duke Energy Corporation and are principally engaged in providing integrated retail and wholesale electric utility service in Ohio and Kentucky, respectively. The Companies, along with Duke Energy Indiana, Inc. (Duke Indiana), another Duke Energy Corporation subsidiary, are transmission-owning members of MISO, and make their transmission facilities available under the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff (MISO ASM Tariff). Therefore, customers that desire transmission service over Duke Ohio's, Duke Kentucky's, or Duke Indiana's transmission facilities currently submit their requests to MISO.

5. The Companies maintain transmission, distribution and generation facilities. Specifically, the Duke Ohio transmission system consists of approximately 400 circuit miles of 345 kV transmission lines and more than 700 circuit miles of 138 kV facilities and interconnects with the transmission systems of American Electric Power Co., Inc. (AEP), Dayton Power & Light Company (Dayton Power), East Kentucky Power Cooperative, Ohio Valley Electric Corp., Louisville Gas and Electric Company, Duke Kentucky, and Duke Indiana. In addition, the Duke Kentucky transmission system consists of 69 kV transmission and distribution facilities and eighteen high-side 138 kV connections. Duke Kentucky is only interconnected with Duke Ohio.

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[4] 16 U.S.C. § 824e (2006).

[5] *Duke Energy Ohio, Inc., et al.*, 133 FERC ¶ 61,058 (2010) (October 21, 2010 Order).

II. **Details of the Filing**

6. On October 14, 2011, the Filing Parties jointly submitted modifications to the PJM OATT, OA, RAA, and TOA, in connection with the Companies' integration into PJM effective January 1, 2012.[6] PJM requests waiver of: (1) the PJM application fee for any Market Buyer applying for PJM membership before January 1, 2012, as a direct result of the Companies joining PJM; and (2) Schedule 9-FERC as it would apply to the Companies for a limited period, so as to avoid over collection of FERC-related fees from the Companies.

7. The Filing Parties state that the Commission requires applicants to satisfy three requirements when proposing to withdraw from an RTO: (1) the withdrawal proposal must satisfy the terms of the applicant's contractual obligations as they relate to RTO withdrawal; (2) the proposed replacement arrangements must comply with Order Nos. 888 and 890 and the standard of review applicable to proposed tariff provisions that differ from the *pro forma* OATT; and (3) the replacement arrangements must be just, reasonable, and not unduly discriminatory.[7]

8. With regard to the first requirement, the Companies state that the Commission ruled that there were five contractual obligations that the Companies had to meet in order to withdraw from MISO. The Companies had to: (1) provide written notice to MISO; (2) ensure the availability of continued transmission service for existing customers; (3) pay their financial obligations to MISO; (4) achieve a negotiated resolution, as between the Companies and MISO, of the Companies' obligations to construct new facilities; and (5) receive all applicable federal and state regulatory approvals.

9. The Companies note that the Commission found in the October 21, 2010 Order that they have satisfied the requirement of providing written notice to MISO. The Companies are attempting to demonstrate in the instant filing that they are ensuring the availability of continued transmission service for existing customers. The Companies are also attempting to demonstrate here that the inclusion of the exit fee in wholesale transmission rates is just and reasonable and consistent with Commission policy. The Companies note that they are currently negotiating with MISO regarding the Companies' obligation to construct new facilities. The Companies further note that they anticipate that this matter will be addressed in a new Schedule 38 of the MISO ASM Tariff to be

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[6] The PJM TOA modifications were filed by PJM on behalf of the PJM Transmission Owners Administrative Committee, which endorsed the modifications on August 15, 2011.

[7] October 21, 2010 Order, 133 FERC ¶ 61,058 at P 14.

filed by MISO. The Companies also state that the Commission ruled in the October 21 Order that they have received the applicable federal and state regulatory approvals, subject to the Companies meeting the conditions in the October 21, 2010 Order, the outcome of the Companies' future filings with the Commission, and the outcome of Duke Kentucky's then-pending filing with the Kentucky Public Service Commission.

10. The Companies note that the purpose of the instant filing is to submit the amendments to the PJM OATT, PJM OA, PJM RAA, and PJM TOA that are necessary to meet the conditions that the Commission imposed in its October 21, 2010 Order. Specifically, the filing contains revisions to the PJM OATT to include the Companies' transmission revenue requirements, which is accomplished by adding the Companies' formula rate as a new Attachment H-22A to the PJM OATT. Included as part of that formula is a set of formula rate protocols that sets forth the opportunity for customers to review the data that the Companies use in calculating their transmission revenue requirements, as well as to challenge those calculations believed to be incorrect. The Companies note that the replacement arrangements satisfy the requirements of Order Nos. 888 and 890,[8] and are just and reasonable and not unduly discriminatory.

11. The Companies state that they are seeking to recover their legacy MISO Transmission Expansion Plan (MTEP) Costs (Legacy MTEP Costs), and, to the extent necessary, their MISO exit fee (MISO Exit Fee) and the costs PJM will charge them in connection with the transition to PJM (PJM Integration Costs), as well as an additional MISO exit fee related to Long-Term Firm Transmission Rights (LTTR Exit Charge) (collectively, Transition Costs). The Companies have included a cost-benefit analysis that attempts to demonstrate that the benefits to wholesale transmission customers from RTO realignment outweigh the Legacy MTEP Costs and Transition Costs that the Companies have included in their formula rate. The Companies argue that the benefits

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[8] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002). *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on reh'g*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

from RTO realignment to the Companies' wholesale customers are far greater than the Legacy MTEP Costs and Transition Costs. Specifically, the Companies state that approximately $301 million will be saved over twenty-five years, on a net present value basis.

12. As discussed in more detail below, the filing proposes both ministerial and substantive changes to PJM's tariff.

A. Ministerial Revisions to the PJM OATT, OA, RAA, TOA

13. PJM explains that the revisions to the PJM OATT, OA, RAA, and TOA are needed to implement the integration of the Companies' service area into PJM on January 1, 2012, in accordance with the Commission's October 21, 2010 Order. To accomplish this integration, PJM is establishing the Companies' service areas as a zone within PJM, to be known as the DEOK Zone. PJM further notes that many changes are ministerial in that they add, where needed, the DEOK Zone and/or the Companies as Transmission Owners to the PJM OATT, OA, RAA, and TOA. The Companies note that PJM's revisions were approved by the PJM Members Committee on August 25, 2011.

B. Substantive Revisions to the PJM OATT

1. Transmission Rates

14. The Companies propose to incorporate revenue requirements and rates for four transmission and ancillary services under the PJM OATT: (1) Network Integration Transmission Service (NITS) (PJM OATT, Attachment H-22); (2) Transmission Owner Scheduling, System Control, and Dispatch Service (Scheduling Service) (PJM OATT, Schedule 1A); (3) Long-Term Firm and Short-Term Firm Point-to-Point (PTP) Transmission Service (PJM OATT, Schedule 7); and (4) Non-Firm Point-to-Point Transmission Service (PJM OATT, Schedule 8). The Companies explain that the rates are based on their existing rates in MISO, with modifications necessary to implement the move to PJM. The Companies state that the rates for all of these services are based on their zonal revenue requirements. The Companies further state that this proposal is consistent with the manner in which the other PJM Transmission Owners calculate such rates, and has been accepted by the Commission.

15. Among the changes necessary to incorporate these services, the Companies explain that they are modifying Parts A and B of Schedule 1A. Specifically, Part A is being modified to state that the rates for such service shall be calculated pursuant to Attachment H-22, Appendix A. The Companies state that Part B is being modified to add the Companies to the list of Transmission Owners, and to indicate that the Companies' share of the revenues from Scheduling Service provided to Non-Zone Load among PJM Transmission Owners is currently 0.00 percent. The Companies note that

they will make a subsequent filing to indicate what share of the credit they will ultimately receive.

2. Changes to Conform to PJM Practices & Address Transitional Issues

16. The Companies propose several changes to their existing formula rate to reflect differences between the PJM and MISO tariffs and practices and to reflect the Companies' integration into PJM. For the NITS rate, the Companies state that they have changed the rate divisor from twelve coincident peak to one coincident peak consistent with section 34.1 of the PJM OATT.[9] For the PTP rates, the Companies state that they have eliminated adjustments between PTP contract demand and loads served using PTP service.

17. In addition, because operation and maintenance (O&M) expenses that are recovered under the Schedule 1A rate are also included in the O&M accounts in the transmission service formula rate, the Companies propose removing O&M expenses from the transmission service formula rate (Note L). Further, the Companies propose to eliminate the revenue credit for non-firm PTP service, since PJM directly credits such revenues to transmission customers.

18. The Companies are also proposing a transitional adjustment to the firm PTP revenues used as a credit in the calculation of the net zonal revenue requirement for the rate years beginning June 1, 2013, and June 1, 2014. The Companies explain that under their formula rate, the Companies' share of firm PTP service revenues for loads sinking outside the DEOK Zone for the prior calendar year is used to reduce zonal revenue requirements for the current rate year beginning June 1. The Companies explain that since they were still members of MISO in 2011, there would be a mismatch between the revenues that they receive and the revenues they credit under their formula rate. Therefore, the Companies include an adjustment that modifies the firm PTP service revenue credits until the revenue credit is based on revenues received in PJM.

3. Changes Related to PJM RTEP Projects

19. The Companies explain that once they join PJM, they will be responsible for the construction of new PJM Regional Transmission Expansion Plan (RTEP) projects in the DEOK Zone consistent with Schedule 12 of the PJM OATT. Additionally, the

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[9] Filing at 25-26 (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,198, at P 10-17, 59-68 (2011) (*ATSI*); *PJM Interconnection, L.L.C., et al.*, 109 FERC ¶ 61,302, at P 20 (2004)).

Companies explain that the costs for such RTEP projects will be allocated to transmission customers as provided for under Schedule 12 of the PJM OATT. Therefore, the Companies state that, in Appendix C to their formula rate, they have included a formula for deriving the annual revenue requirement for any RTEP projects assigned to the Companies. The Companies note that the revenue requirements calculated under Appendix C will be provided to PJM for developing zonal rates under PJM OATT Schedule 12. The Companies further note that the same revenue requirement derived in Appendix C and provided to PJM for inclusion in PJM OATT Schedule 12 rates will be used to offset the zonal revenue requirements in their formula rate. The Companies explain that this proposal is similar to the manner in which *ATSI* treated this cost.

4. <u>Protocols</u>

20. The Companies state that they have included formula rate implementation protocols as part of their formula rate (Attachment H-22B) (Protocols). The Companies note that the Protocols provide for the rates to be recalculated on an annual basis and give customers and other interested parties the opportunity to monitor the operation of the formula rate. In addition, the Protocols provide for the Companies to submit their formula rate calculations to the Commission for informational purposes, give interested parties the opportunity to conduct discovery with respect to the Companies' charges, and establish a procedure for interested parties to challenge the Companies' calculations if they believe the calculations are incorrect. The Companies state that the Protocols are substantially the same as Commonwealth Edison Company's (Commonwealth Edison) formula rate protocols, with definitions added from AEP Transmission Companies' formula rate protocols.[10]

21. The Companies note that Attachment H-22B states that depreciation rates (transmission, general plant, and intangible plant) and post-employment benefits other than pensions (PBOP) expenses shall be stated values until changed pursuant to an FPA section 205 or 206 filing made effective by the Commission. The Companies further note that the depreciation rates and PBOP values are the same as the ones they are using in MISO, and thus do not constitute a change from the existing rate.

C. <u>Recovery of Legacy MTEP and Transition Costs</u>

22. After the Companies are integrated into PJM, they will continue to be obligated to pay for a portion of the costs of certain Legacy MTEP projects identified in the MTEP and approved by the MISO Board of Directors prior to the Companies' integration into

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[10] *Id.* at 31 (citing *Commonwealth Edison Co. and Commonwealth Edison Co. of Indiana, Inc.*, 122 FERC ¶ 61,030 (2008)).

PJM. In addition, after the integration, transmission owners serving load in zones other than the DEOK Zone will continue to be obligated to pay for the cost of the one Legacy MTEP project that the Companies have built in their zone, thereby paying a portion of the cost of facilities included in the Companies' formula rate.

23. The Companies propose to amend the PJM OATT to address both of these issues. First, MISO will bill PJM for the cost of Legacy MTEP projects in zones other than the DEOK Zone for which the Companies remain responsible, and PJM will bill customers in the DEOK Zone for these costs. Second, the Companies state that the revenues from transmission owners serving load in zones other than the DEOK Zone for the cost of the one Legacy MTEP project whose cost is included in the Companies' PJM transmission revenue requirements will continue to be credited against the Companies' costs.[11]

24. The Companies note that because of this charge and credit, there needs to be a process in the PJM OATT for charging costs and distributing revenues related to Legacy MTEP facilities. Therefore, the Companies propose to include a new Attachment JJ to the PJM OATT. The Companies explain that Attachment JJ sets forth the method by which transmission customers taking service for deliveries in the DEOK Zone will be charged for the cost of Legacy MTEP projects constructed by other MISO transmission owners, the method by which PJM will transmit to MISO the revenues received from transmission customers taking service for deliveries into the DEOK Zone for such Legacy MTEP projects, and the manner in which PJM will distribute revenues received from MISO for the Legacy MTEP projects constructed by the Companies.

25. The Companies state that under Article Five, Section II.B of the MISO Transmission Owners' Agreement (MISO TOA), the Companies are required to pay certain amounts to MISO as an exit fee. The Companies explain that the MISO Exit Fee compensates MISO for certain long-term costs that MISO incurs in connection with the services that it provides. The Companies note that they have executed an Exit Fee Agreement with MISO, which sets forth how the MISO Exit Fee will be calculated. The Companies state that the Exit Fee Agreement was filed with the Commission on October 5, 2011 in Docket No. ER12-33-000. The Companies also state that they

[11] The Companies currently receive payments from MISO transmission customers in other transmission zones for their share of the revenue requirement associated with projects the Companies constructed or will construct under the MTEP process.

anticipate that the MISO Exit Fee will be approximately $14.4 million. The Companies propose to include the MISO Exit Fee in their transmission rates.[12]

26. In addition, on July 29, 2011, MISO filed, on behalf of itself and the Companies, an executed Settlement Agreement in Docket Nos. ER11-2059 *et al.* The Companies explain that under the Settlement Agreement, they will pay to the MISO $1.8 million to resolve the dispute between the Companies and MISO over tariff revisions proposed to address alleged adverse effects on the feasibility of the LTTR Exit Charge resulting from the withdrawal of the Companies from MISO. Like the MISO Exit Fee, the Companies propose to recover these costs in wholesale rates, because these costs are being imposed as a result of withdrawing from MISO.

27. The Companies also state that they anticipate that PJM will charge them up to approximately $1 million for PJM Integration Costs, i.e., the costs in connection with the transition to PJM. As O&M expenses, these costs will flow through the Companies' existing formula rate. The Companies state that the MISO Exit Fee, LTTR Exit Charge, and the PJM Integration Costs comprise the Companies' Transition Costs.

28. The Companies propose to include the Transition Costs in the formula rate. They state that in order to provide additional transparency as well as to ensure the proper cost allocation, they have added lines to the formula rate to accommodate these costs. In order to prevent double-recovery of these costs, the Companies added lines to the formula rate to subtract the costs from the O&M and administrative and general (A&G) expenses of which they are a part.

D. Cost-Benefit Analysis

29. The Companies state that the proposed amendments to the PJM OATT, OA, RAA, and TOA should be approved. The Companies state that the amendments constitute the changes that are needed to these documents to comply with the October 21, 2010 Order. In addition, the Companies state that the replacement arrangements comply with Order Nos. 888 and 890, and are just and reasonable and not unduly discriminatory.

30. The Companies state that the proposed amendments to the PJM OATT result in existing transmission customers receiving service on terms and conditions that are comparable to the terms and conditions under which they currently receive transmission service. In addition, these customers will be subject to the same formula rate, modified

[12] *See Midwest Independent Transmission System Operator, Inc., et al.*, 137 FERC ¶ 61,198 (2011) (conditionally accepting the Exit Fee Agreement between MISO, Duke Ohio, and Duke Kentucky).

as necessary to reflect the transition to PJM. The Companies also state that the inclusion of Legacy MTEP Costs and Transition Costs in their rates is consistent with Commission precedent.[13]

31. The Companies state that they should not be required to demonstrate that the benefits of moving to PJM outweigh the prudently incurred costs of the RTO realignment in order for them to include such costs in their rates. The Companies note that under the FPA, a utility is entitled to recover its prudently incurred costs of providing service.[14] Therefore, the Companies state that their formula rate recovers their actual costs, so the only question here is whether the costs incurred were prudent. The Companies explain that the costs at issue were incurred in order to continue to provide Commission-approved service in the DEOK Zone, and were prudently incurred on behalf of the Companies' customers. The Companies also note that the Commission has approved the incurrence of Legacy MTEP Costs in various cases approving establishment of the MTEP mechanism.[15] The Companies state that customers in the DEOK Zone would be responsible for paying for Legacy MTEP Costs regardless of whether they departed from MISO.

32. The Companies state that, because the incurrence of these costs has already been deemed prudent, it would be a form of regulatory "double jeopardy" to require the

[13] Filing at 35 (citing *Virginia Elec. & Power Co.*, 125 FERC ¶ 61,391 (2008), *reh'g denied*, 128 FERC ¶ 61,026 (2009); *New York Indep. Sys. Operator, Inc., et al.*, 92 FERC ¶ 61,180 (2000); *PJM Interconnection, L.L.C. and Allegheny Power*, 96 FERC ¶ 61,060, at 61,222-23 (2001), *order approving uncontested settlement*, 100 FERC ¶ 61,088 (2002); *Am. Elec. Power Serv. Corp.*, 113 FERC ¶ 63,031, *order approving uncontested settlement*, 113 FERC ¶ 61,294 (2005), *as corrected*, 115 FERC ¶ 61,114 (2006)).

[14] *Id.* at 37 (citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Miss. Power Co.*, 50 FPC 885, 912 (1973); *New England Power Co.*, 49 FERC ¶ 63,007, at 65,038 (1989), *aff'd in relevant part,* 52 FERC ¶ 61,090 (1990); *Pub. Serv. Comm'n of N.Y. v. FPC,* 467 F.2d 361, 370 (D.C. Cir. 1972)).

[15] *Id.* at 37 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 FERC ¶ 61,106, *order on technical conference, reh'g, clarification, and compliance*, 117 FERC ¶ 61,241 (2006), *order on reh'g and clarification*, 118 FERC ¶ 61,208 (2007); *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,209, *order on reh'g and compliance filing*, 120 FERC ¶ 61,080 (2007), *order on reh'g and compliance filing*, 122 FERC ¶ 61,127 (2008)).

Companies to again justify recovery of the same costs. Nor does withdrawal from MISO mean that second guessing the prudence of incurring those costs is appropriate, they argue. The Companies further state that the Commission has authorized companies to recover prudently incurred RTO start-up costs even if incurrence of the costs does not lead to membership in an RTO.[16] In some such cases, recovery has been through the rates of a different RTO that the company subsequently joins.[17]

33. Despite arguing that no cost-benefit analysis should be required, the Companies submit a cost-benefit analysis attempting to demonstrate that the benefits of the move substantially outweigh the costs.[18] The Companies state that both quantified factors and unquantified factors weigh strongly in favor of the RTO realignment and support recovery of Transition Costs and Legacy MTEP Costs.

34. The Companies explain that the study analyzed costs and benefits in two categories: quantified costs and benefits and unquantified costs and benefits. Unquantified costs and benefits consist of those categories of costs and benefits that would be hard to measure, and those categories of costs and benefits that are not expected to vary significantly between the RTOs—namely local costs in zonal transmission rates, and energy, capacity, and ancillary services costs. Quantified costs consist of high voltage transmission upgrade costs in both RTOs, RTO administrative costs, and Transition Costs.

35. The Companies state that Mr. Stoddard compared two cases to determine the gross cost or benefit of the move. First, the Companies state that Mr. Stoddard created a hypothetical comparison case where he calculated costs for DEOK Zone customers if the Companies remain in MISO in 2012 and beyond. Then the Companies state that Mr. Stoddard calculated costs for DEOK Zone customers if the Companies are in PJM beginning January 1, 2012. The Companies explain that the result of this comparison is a

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[16] *Id.* at 38 (citing *Idaho Power Co.*, 123 FERC ¶ 61,104, at P 10 (2008) (allowing recovery of $4.6 million in costs incurred in utility's unsuccessful attempt to develop an RTO)).

[17] *Id.* at 38 (citing *Illinois Power Co. and Midwest Independent Transmission System*, 108 FERC ¶ 61,258, at P 3, 6 (2004) (authorizing recovery under the MISO tariff for $8.7 million in start up costs associated with Illinois Power's efforts to form the Alliance RTO)).

[18] *Id.* at 39. In support their request to recover Legacy MTEP and Transition Costs, the Companies have attached the direct testimony of Mr. Robert B. Stoddard.

gross benefit of $819.4 million. The net benefit (after Transition Costs and Legacy MTEP Costs are subtracted) of the move is projected to be $301 million through 2036.[19]

36. Although they will begin their time in PJM under Fixed Resource Requirements (FRR) plans, the Companies state that they and their zonal customers will "benefit from the stability of the well-established [Reliability Pricing Model] RPM design" because "RPM allocates the costs of maintaining resource adequacy equitably, meaning there is value in having the competitively determined [Base Residual Auction] BRA price available to use as backstop price for capacity sales to competitive retail suppliers in the absence of any explicit state cost allocation mechanism."[20]

37. The Companies state that the proposed PJM OATT amendments give their existing transmission customers continued access to transmission service under rates, terms, and conditions that are comparable to those available under the MISO ASM Tariff. In addition, the Companies state that their integration with PJM satisfies the requirements with Order Nos. 888 and 890.

E. Waiver Requests

38. PJM requests waiver of the $1,500 PJM application fee for Market Buyers applying for PJM membership as a direct result of the Companies' integration into PJM. PJM and the Companies state that this limited waiver would not apply to Market Buyers joining PJM after January 1, 2012, and will not apply to a Market Buyer or other applicants seeking PJM membership for reasons unrelated to the Companies' integration. The Companies argue that this waiver is appropriate because the costs that the application fee is intended to cover have already been paid by the Companies as part of their integration costs, such that there is no need to charge Market Buyers this fee.

39. PJM also requests waiver of Schedule 9-FERC, which concerns PJM's billing of the annual FERC charge attributable to the Transmission Owners in the PJM region. PJM states that as the Commission will utilize transmission volumes from 2011 for the 2012 FERC Annual Charge, the MISO's 2012 annual charge will include the Companies' transmission volumes and PJM's 2012 annual charge will not. Therefore, the MISO will bill the Companies directly for the 2012 FERC Annual Charge assessed to the MISO for the Companies' 2011 transmission volumes. PJM explains that if it started assessing this

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[19] Most of the cost savings calculated in the Companies' analysis come from the projected difference between future MTEP costs ($948.4 million) and future [spell out] (RTEP) costs ($657 million). Filing at 45.

[20] *Id.* at 46.

fee to the Companies as soon as they join PJM, the Companies would have to pay a disproportionate share of the annual assessment. Therefore, to ensure that the Companies are not over- or under-assessed their share of the annual Commission fees, PJM is requesting a temporary waiver of Schedule 9-FERC of the PJM OATT charges to the DEOK Zone. PJM notes that the waiver would cover the period beginning with the planned integration date of January 1, 2012 and expire on September 30, 2012.

40. The Companies request, to the extent necessary, waivers of the Commission's cost support regulations in 18 C.F.R. § 35.13 (2011), including waiver of the full Period I-Period II data requirements, waiver of the attestation concerning Period II submissions required by section 35.13(c)(6), and waiver of the requirements in section 35.13(a)(2)(iv) to determine if, and the extent to which, a proposed change constitutes a rate increase based on Period I-Period II rates and billing determinants. The Companies state that good cause exists for such waiver. Specifically, the Companies state that the testimony and exhibits accompanying this filing, together with the Companies' publicly available FERC Form No. 1 information, provide ample support for the reasonableness of the proposed formula rate. In addition, the Companies note that such waiver is consistent with Commission precedent for a formula rate of this nature.[21]

41. PJM and the Companies request an effective date of January 1, 2012, for the rates, terms, and conditions for transmission service that are described above.

III. Notice of Filing and Responsive Pleadings

42. Notice of the Companies' submittal was published in the *Federal Register*, 76 Fed. Reg. 65,716 (2011), with protests and interventions due on or before November 4, 2011. Motions to intervene were filed by Exelon Corporation, MISO, and Indiana Municipal

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[21] *Id.* at 55-56 (citing *Southern California Edison Co.*, 136 FERC ¶ 61,074, at P 29 (2011) (granting waiver of Period I and II data); *Pub. Serv. Elec. & Gas Co.*, 124 FERC ¶ 61,303, at P 23-24 (2008) (granting waiver of sections 35.13(d)(1)-(2), 35.13(d)(5), and 35.13(h)); *Oklahoma Gas & Elec. Co.*, 122 FERC ¶ 61,071, at P 41 (2008) (same); *Am. Elec. Power Serv. Corp.*, 120 FERC ¶ 61,205, at P 41 (2007) (granting waiver of Period I and II data); *Commonwealth Edison Co.*, 119 FERC ¶ 61,238, at P 92-94 (2007) (granting waiver of Period I and II data and cost-of-service statements); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, at P 57 (2007) (same); *Duquesne Light Co.*, 118 FERC ¶ 61,087, at P 79 (2007) (granting waiver of sections 35.13(d)(1)-(2) and 35.13(h)); *Idaho Power Co.*, 115 FERC ¶ 61,281, at P 20 (2006) (granting waiver of Period II data); *Allegheny Power Sys. Operating Cos.*, 111 FERC ¶ 61,308, at P 55-56 (2005) (granting waiver of Period I and II data)).

Power Agency. Motions to intervene and protests were filed by American Municipal Power, Inc. (AMP) and IMPA.[22] A late-filed motion to intervene was filed by the City of Hamilton, Ohio. The protests raise issues regarding the Companies' formula rate, protocols, cost-benefit analysis, and return on equity (ROE). On November 21, 2011, the Companies filed an answer to the protests (Answer). On December 6, 2011, IMPA and AMP jointly filed an answer to the Companies' answer, and on December 16, 2011, the Companies filed a motion to answer and answer.

IV. <u>Discussion</u>

A. <u>Procedural Matters</u>

43. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[23] the timely, unopposed motions to intervene serve to make the parties that filed them parties to this proceeding. Given the early stage of this proceeding and the absence of undue prejudice or delay, we grant the unopposed late-filed motion to intervene submitted by the City of Hamilton.

44. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure[24] prohibits an answer to a protest or to an answer unless otherwise ordered by the decisional authority. We accept the Companies' answer because it has aided us in our decision-making process. We reject, however, AMP and IMPA's December 6, 2011 joint answer to the Companies' answer, and the Companies December 16, 2011 answer in response.

B. <u>Settlement Agreement</u>

1. <u>Description</u>

45. The Settlement Agreement provides that Duke Ohio will reimburse IMPA for its obligation to pay the PJM transition costs owed to the Companies by IMPA associated

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[22] Pursuant to the Settlement Agreement, IMPA agrees to move to withdraw its protest within fifteen days of the earlier of issuance of a Commission order accepting (a) the Settlement Agreement without modification or condition, or (b) the PJM formula rate and not modifying or conditioning the Settlement Agreement. Since the order approves the settlement, IMPA's issues are not discussed.

[23] 18 C.F.R. § 385.214 (2011).

[24] 18 C.F.R. § 385.213(a)(2) (2011).

with the load that IMPA serves for the Village of Blanchester, Ohio.[25] These credits will be provided through a PJM line item transfer allocation to credit IMPA at the time payment is due so their respective payment obligation for the affected months will be effectively zero. The PJM RTEP cost credit for IMPA will expire when the credit amount reaches the defined RTEP credit cap amount of $575,000. In the event that the PJM formula rate as filed by the Companies is modified for any reason, the IMPA PJM credit cap is reduced to reflect IMPA's savings from any such rate reduction.

46. The Settlement Agreement is without prejudice to IMPA's right to raise the issue of the Companies' rate of return on equity in subsequent proceedings, through a filing under Federal Power Act section 206 or otherwise,[26] provided that IMPA agrees that it will not (a) initiate a proceeding prior to January 1, 2016 seeking a reduction of the Companies' rate of return on equity, or (b) in any proceeding initiated by others support a reduction of the rate of return on equity specifically applicable to the Companies in which the reduction would become effective prior to January 1, 2016.

47. The Settlement Agreement provides that unless the settling parties otherwise agree in writing, any modifications to this Settlement Agreement proposed by one of the settling parties after the Settlement Agreement has been accepted or approved by the Commission shall, as between them, be subject to the public interest application of the just and reasonable standard of review set forth in *United* Gas *Pipe Line Co. v. Mobile* Gas *Servo Corp.,* 350 U.S. 332 (1956) and *Federal Power Commission V. Sierra Pacific Power Co.,* 350 U.S. 348 (1956) (the *Mobile-Sierra* doctrine), as clarified in *Morgan Stanley Capital Group, Inc. V. Public Util. Dist. No.1 of Snohomish County, Washington,* 128 S.Ct. 2733, 171 L. Ed. 2d 607 (2008) and refined in *NRG Power Mktg. V. Maine Pub. Uti/so Comm'n,* 130 S. Ct. 693, 700 (2010). Any modifications proposed by the Commission acting *sua sponte* or by a non-settling party shall be subject to the just and reasonable standard.

48. The Companies state that the Settlement Agreement resolves all issues between the Companies and IMPA in this proceeding. Further, the Companies state that negotiations with AMP have reached an impasse. AMP submitted a response that confirms negotiations between the Companies and AMP are at an impasse, and requests

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[25] IMPA is required to pay its respective share of the rates approved in these proceedings, including but not limited to its share of Legacy MTEP Costs, subject to the reimbursements and credits.

[26] 16 U.S.C. § 824e (2006).

the Commission issue an order on the Companies October 14, 2011 filing as soon as possible.

2. Commission Determination

49. We approve the provisions of the Settlement Agreement. The Settlement Agreement resolves all outstanding issues between the Companies and IMPA. The Settlement Agreement provides that IMPA will, as discussed below, be reimbursed for its obligation to pay for a portion of the Transition Costs and PJM RTEP Costs. The Settlement Agreement is fair and reasonable and in the public interest, and is approved. The Commission's approval of the Settlement Agreement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding. The Commission retains the right to investigate the rates, terms and conditions under the applicable standard of review set forth in the Settlement Agreement. In the compliance filing, as discussed below, the Companies must include in its Tariff the provisions that provide for the PJM RTEP credit and credit cap mechanism of the Settlement Agreement.

50. The Settlement Agreement does not resolve issues raised by AMP, and because negotiations with AMP are at an impasse, we will sever the parties and consider the issues raised by the protest of AMP, as applicable to all customers other than IMPA.

C. Tariff Issues

51. As discussed below, the proposed Tariff modifications are rejected in part, and accepted in part, suspended for a nominal period, to become effective January 1, 2012, subject to refund, and the submission of a compliance filing and a refund report.

1. Formula Rate Provisions

a. Protest

52. AMP takes issue with several proposed provisions of the formula rate. For example, it takes issue with Schedule 1A of the formula rate because there is no indication as to when the Companies' share of revenues will be determined such that the formula rate input may be changed. It further takes issue with the Protocols that the Companies developed without input from their transmission customers. AMP states that the provisions impermissibly limit the rights of customers to initiate and pursue challenges to the annual rate inputs.[27] AMP requests that the Commission suspend the

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[27] AMP Protest at 25-35.

tariff revision proposed herein and set for hearing all issues pertaining to the justness and reasonableness of the proposed tariff changes.

b. Answer

53. With respect to AMP's concern with Schedule 1A, Part B, the Companies clarify that the scheduling charges to which AMP may be subject under this schedule arise because the Companies are joining PJM. The Companies note that they are not making any changes to those charges; they occur automatically by virtue of the Companies becoming PJM transmission owners. In addition, the allocation of the Schedule 1A, Part B credit is set forth in a series of fixed allocation percentages that cannot be changed absent a filing with the Commission. The Companies state that they plan to work to resolve this transitional matter with PJM and the other participating transmission owners. Pending the outcome of those efforts, the Companies explain that it will be subject to review by the Commission and AMP will have the opportunity at that point to present its views on the matter. Therefore, the Companies state that there is no reason for delaying the effectiveness of the Schedule 1A, Part B charges as AMP proposes.

54. The Companies state that they agree with AMP that page 1, line 5b, of the formula rate, which credits the transmission revenue requirement for revenues received by the Companies for transmission enhancement projects for which the Companies are responsible, is unnecessary. The Companies state that they discovered that PJM credits customers directly for their share of such revenues. Therefore, the Companies state that they are deleting page 1, line 5b, of the formula rate.

55. With regard to AMP's concern on the lack of information regarding PTP revenue credits, the Companies propose to add language to Appendix E for clarification. Specifically, the Companies propose to add the following to Note C of the workpaper to Appendix E if the Commission believes it is necessary: "The recovery of amounts deferred between January 1, 2012, and December 31, 2012, will begin on June 1, 2013, and will end on May 31, 2014. The recovery of the amounts deferred between January 1, 2013 and May 31, 2013, will begin on June 1, 2014, and will end on May 31, 2015."

56. The Companies note that Appendix B to the application is a calculation of their revenue requirement for RTEP projects that the Companies construct in PJM. They note that Appendix B is not populated with anything at this time because they do not have any RTEP projects to include. Therefore, the Companies argue that populating Appendix B with pretend data, as AMP is suggesting, would serve no useful purpose.

57. The Companies state that they have corrected a typographical error on Appendix E, page 1. Specifically, the Companies state that Appendix E, page 1, line 9, should be to Note D, not Note C, and it should be placed on line 8 not line 9.

58. The Companies argue that AMP's request for hearing on the issues raised in its protest does not meet the Commission's standard for demonstrating the need for an evidentiary hearing. For example, the Companies argue that AMP has not made an adequate proffer of evidence to support facts that materially and genuinely contradict the evidence that they have presented. Therefore, the Companies argue that the Commission should decline AMP's request for hearing.

59. With respect to the formula rate protocols, the Companies state that they have developed their protocols by largely copying existing protocols on file with the Commission for a transmission owner in PJM (Commonwealth Edison). They explain that Commonwealth Edison's protocols were the product of a settlement agreement that was agreed to by a diverse set of stakeholders. Although the Companies believe that following Commonwealth Edison's protocols is just and reasonable, they state that they generally have no objection to AMP's suggestions to follow AEP's protocols. Therefore, the Companies explain that they have either made the suggested edits or have contacted counsel for AMP to resolve the issue. The Companies state that their proposed changes resolve all issues related to the Protocols.

c. <u>Commission Determination</u>

60. With respect to AMP's concern about Schedule 1A, Part B, we find the Companies' explanation sufficient and accept the Companies' modification, subject to the condition that the Companies revise their Tariff to provide that any change to this rate must be made as a tariff filing under section 205 of the FPA. We further reject AMP's request that the Companies provide an example of a completed Appendix B in Attachment H-22A. As the Companies note, they do not currently have any RTEP projects to include in Appendix B. We also note that the Companies have provided the underlying electronic copy of the formula rate to AMP and have offered to provide such information to any customer upon request.

61. To address concerns raised by AMP, we will accept the following proposed changes to the formula rate subject to the Companies making a compliance filing, within 30 days of the date of this order, making the changes suggested in the Companies' Answer. Specifically, the compliance filing should eliminate the currently-proposed page 1, line 5b and should add the two proposed clarifying sentences in Note C of the workpaper to Appendix E. Additionally, the compliance filing should correct the typographical error in Appendix E of Attachment H-22A, Note C, as indicated in the Companies' Answer.

62. With respect to the formula rate Protocols, AMP raised several concerns and proposed specific changes. In their Answer, the Companies state that they do not object to making the changes suggested by AMP. The Companies propose the specific changes in Attachment B to their Answer.

63. We will accept the Companies' Protocols subject to the Companies making a compliance filing, within 30 days of the date of this order, making the changes discussed in their Answer. While we accept the Companies' proposed changes, we note that in approving any formula rate, the Commission approves the formula itself, the algebraic equation used to calculate the rates. The Commission does not approve the inputs into the formula or the charges resulting from the application of the inputs to the algebraic equation.[28] As we found in *AEP*, any challenge to the projected costs, True-Up Adjustment or Material Accounting Change would not require the complainant to bear the ultimate burden of proof. Rather, the Companies will continue to bear the burden of proof, i.e., to demonstrate the justness and reasonableness of the charges resulting from application of the formula rate.

2. Recovery of Legacy MTEP Costs

a. Protest

64. AMP argues that the Companies failed to demonstrate that the benefits transmission customers will enjoy from the realignment outweigh the Transition Costs. Protestors argue that the Commission should not allow the Companies to collect Transition and Legacy MTEP Costs from wholesale customers, and AMP states that the Commission should at least establish evidentiary procedures to resolve issues of material fact.

65. AMP takes issue with the Companies' reliance on the study Regional Generation Outlook Study (RGOS). AMP argues that this study is one set of data pints in the RTO's consideration of their respective long-term transmission expansion costs and the Companies have made no effort to corroborate the RGOS estimates by comparing them to values developed in other MISO and PJM long-range studies. AMP also argues the Companies did not undertake to determine the continuing validity of the RGOS study's fundamental assumptions.

66. With respect to purported non-quantifiable benefits, AMP contends that the Companies err by relying on the benefits of PJM's capacity market. AMP notes that the Commission clearly spoke of benefits that accrue to transmission customers, which capacity market do not benefit. AMP is also not persuaded by any unidentified "wide range of benefits" that the Companies claim from the transition. In order to satisfy the *ATSI* burden of demonstrating that benefits exceed costs, AMP states that the Commission should require the Companies to submit a more complete and well-reasoned

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[28] *See American Electric Power Service Corporation*, 124 FERC ¶ 61,306, at P 33-36 (2008); *see also Virginia Electric and Power Company*, 123 FERC ¶ 61,098 (2008).

analysis. It states that the purpose of the *ATSI* standard is to protect customers from realignments costs, particularly when a company decides to switch RTOs for its own commercial reasons.

67. AMP also states that retail customers of the Companies will largely be spared the burden of paying the same RTO realignment costs that the Companies wish to charge wholesale transmission customers. As a result, it alleges that wholesale transmission customers will be treated in a non-comparable manner relative to retail transmission customers, which could result in a price squeeze.

b. Answer

68. In their Answer, the Companies first argue that AMP's proposed treatment of Multi-Value Projects would increase net benefits. For example, AMP argues that the Companies should have accounted in their analysis for the possibility that the DEOK Zone will not be assigned cost responsibility for all of the MVP projects included in the Legacy MTEP category, because some of them may not be approved before the Companies withdraw from MISO. The Companies argue that this adjustment would actually increase the net benefit to AMP and other customers in the DEOK Zone because it would result in less Legacy MTEP Costs.[29]

69. Second, the Companies argue that the use of non-averaged RGOS data does not materially affect the net benefits showing. The Companies calculated the RGOS values separately for each of the three scenarios, and show that under one scenario the net benefit would increase, under another it would decrease slightly, and under the third, it would decrease a bit more, by less than five percent, from $301 million to $287.6 million.

70. Third, the Companies argue that they appropriately accounted for PJM transmission expansion. The Companies further argue that their estimation of future transmission builds in PJM is not limed to RGOS. The Companies explain that their analysis also includes the substantial backbone east-west transmission projects that PJM does intend to build the Potomac-Appalachian Transmission Highway and Mid-Atlantic Power Path projects as well as the backbone east-west project already included in rates (Trans-Allegheny Interstate Line), and further provides for continued additions of non-RTEP transmission consistent with historic trends.

71. The Companies argue that PJM could build an additional $6.5 billion in transmission (beyond the RGOS and other amounts included in the analysis), to be socialized on a regional load-ratio share basis, without turning the net benefit to

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[29] Answer at 6-7.

customers in the DEOK Zone into a net cost. In addition, the Companies argue that even if their assumptions are widely off the mark, there are still substantial unquantified benefits to consider.

72. The Companies state that the methodology used in their cost-benefit analysis meets the *ATSI* test. Specifically, the Companies state that *ATSI* clearly specified the costs to be analyzed: PJM Integration Costs, deferred integration costs, MISO exit fees, and Legacy MTEP Costs. Protestors contend that the test should be after-the-fact, not before-the-fact, that it should require a net benefit each year rather than over time, that it should address other categories of costs for which recovery is not sought, and that use of the best available forward looking data is not good enough. The Companies respond by arguing that they should be entitled to rely on the test that was in place at the time their decision to move to PJM became irreversible.

73. The Companies argue that they were not required to address capacity costs because the *ATSI* test includes neither energy nor capacity costs among the specifically enumerated costs to be included in the analysis. The Companies note that the analysis did not need to include these costs because the test was for the inclusion of costs in the Companies' zonal transmission rates, and the Companies do not seek recovery of capacity costs in their zonal transmission rate. However, the Companies point out that they did address these costs by concluding that they did not expect material differences between the two regions over time.

74. The Companies argue that they used the best available data for forward-looking projections and that the Protestors are essentially attacking the *ATSI* test itself. The Companies state that the rigid view of data sufficiency and insufficiency taken in the protests is not reflective of the ratemaking principles of the FPA. The Companies contend that they are required to show that the rate is just and reasonable.[30] This showing does not require a demonstration that the rate is perfect, but rather merely that it is reasonable in light of the totality of the circumstances.[31]

75. The Companies also argue that the hold harmless provision in the MISO TO Agreement does not require them to indemnify all MISO market participants from all changes related to their departure. To even be considered for hold harmless treatment, a

[30] Answer at 20 (citing 16 U.S.C. § 824d (2006)).

[31] *Id.* at 20 (citing *Pac. Gas and Elec. Co.*, 113 FERC ¶ 61,084, at P 24 (2005) (concurring with Initial Decision conclusion that ("[F]or the rate design proposal to be acceptable it need be neither perfect no[r] even the most 'desirable'; it need only be reasonable.") (internal cites omitted)).

customer must show that it had transmission service in the zone that began before the Companies gave notice to MISO of their withdrawal, and that the same contract for service will continue after withdrawal. The Companies note that IMPA has not alleged such eligibility.

c. Commission Determination

76. We find that the Companies have not sufficiently demonstrated that wholesale transmission customers will realize net benefits from the realignment, and thus we cannot find at this time that the Companies' proposal to recover the Legacy MTEP and Transition Costs through their formula rates is just and reasonable. Therefore, the Companies must exclude such costs from their formula rate. The Companies must re-file, within 30 days of the date of this order, their proposed tariff sheets and a refund report reflecting the removal of these costs from their formula rate.

77. In *ATSI*, the Commission stated that, if ATSI sought to recover its transition costs, it would have to show that the "benefits to wholesale transmission customers exceed the costs of the realignment, i.e., the PJM Integration Costs, deferred integration costs, and MISO exit fees, including Legacy MTEP costs."[32] The Companies provided a quantitative analysis that relied on a comparison of expected transmission expansion costs in PJM and MISO. We find this analysis to be insufficient.

78. In *ATSI*, the Commission did not elaborate on the form or substance of the cost-benefit analysis that would be needed to satisfy the standard established in that order. In this proceeding, the Companies have submitted a cost benefit study for the Commission's evaluation, and Protesters have argued that the study is incomplete because it omits several categories of cost. Upon consideration of the actual filing and the protests, we have determined that the Companies' cost benefit study is insufficient, because it does not include energy and capacity costs that wholesale transmission customers also have to pay. The purpose of the cost benefit study is to examine whether the Companies' customers would benefit from the transition from MISO to PJM. Such a study needs to include the full range of costs and benefits to which these customers will be exposed. We find any such demonstration of net benefits needs to include a consideration of costs and benefits beyond expected transmission expansion costs, including, but not limited to,

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[32] *ATSI*, 135 FERC ¶ 61,198 at P 60.

RTO administrative costs, energy, capacity, and ancillary service costs resulting from the move from one RTO to another.[33]

79. Our finding is without prejudice to the Companies submitting a new FPA section 205 filing seeking recovery of these costs.

D. Return on Equity

1. Protest

80. AMP argues that the Companies have failed to show that applying the Companies' existing 12.38 percent ROE in the proposed new context of PJM rates is just and reasonable. AMP contends that the basis on which that ROE was approved was specific to the MISO context. Specifically, the ROE was based on a discounted cash flow (DCF) analysis of a proxy group consisting exclusively of MISO transmission owners, and the selection of a midpoint value since the ROE would apply across-the-board to MISO transmission owners rather than to a single company.

81. AMP argues that a value derived in this way is inappropriate for carryover to the PJM Tariff. AMP states that, unlike MISO, transmission rates under the PJM OATT are not based on a group ROE that applies to all transmission owners. Rather, each PJM transmission owner must propose its own ROE and support that value using a DCF methodology that is suitable for termination of a single-company return. AMP states that the Commission's practice is to utilize the median when determining a single-company's return.[34]

82. In addition, AMP contends that the proxy group used to determine the 12.38 percent ROE for the MISO transmission owners in 2002 is wholly unsuitable for use in determining a just and reasonable return for the Companies on a stand-alone basis as members of PJM. Rather, AMP states that the Commission has recently found that the use of a national proxy group is an appropriate starting point for identifying companies with comparable risks.[35]

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[33] The Companies' claim that they do not expect material differences over time in the price for energy and capacity in the two RTOs is a factual issue not currently before us.

[34] AMP Protest at 21-22 (citing *Duke Energy Carolinas, LLC,* 137 FERC ¶ 61,058, at P 23 (2011)).

[35] *Id.* at 22 (citing *Duke Energy Carolinas, LLC,* 137 FERC ¶ 61,058 at P 22).

83. Finally, AMP states that the ROE found appropriate for the MISO pricing zones in 2002 is greatly out of sync with current capital market conditions. For example, AMP states that the market yield on 10-year US Treasury bonds (constant maturity) stood at 5.08 percent on May 1, 2002, approximately when the ALJ in Docket No. ER02-485 rendered his initial decision. On November 1, 2011, the comparable market yield on 10-year Treasury bonds was 2.01 percent. Therefore, AMP argues that today's capital market conditions are quite different than those that existed when the Commission established the 12.38 percent ROE that DEOK seek to carry into their PJM transmission rates.

84. AMP developed a preliminary DCF analysis of DEOK using the national proxy group of fifteen utilities accepted by the Commission in *Duke Energy Carolinas, LLC.* In its analysis, AMP uses DCF data inputs for the six-month period of May-October 2011, and the median return of that group is 9.50 percent. With the addition of 50 basis points for PJM RTO participation, AMP determines an overall ROE of 10.0 percent. AMP argues that reducing the Companies' ROE by 238 basis points (from 12.38 percent to 10.0 percent) would cause a reduction in the Companies' annual transmission revenue requirement of approximately $6.66 million.

85. AMP requests that the Commission clarify whether the 12.38 percent ROE may be challenged in the context of the instant section 205 proceeding, or whether AMP or others will need to proceed by filing a complaint under section 206 of the FPA. If the Commission permits the ROE to be challenged in the instant docket, AMP recommends that the Commission set the ROE issue for hearing so that a full record concerning all relevant factors may be developed.

2. <u>Answer</u>

86. The Companies state that they are not proposing to depart from the status quo with regard to the ROE, and they therefore argue that they do not need to demonstrate the reasonableness of the proposed ROE.[36] The Companies argue that the question at issue here is whether the Commission has the statutory authority to reach the question of whether the Companies' existing ROE is just and reasonable in view of the fact that they are not changing this aspect of their existing rate. The Companies contend that the Commission does not have that authority in this section 205 proceeding.

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[36] Answer at 29-30 (citing *Duke Energy Carolinas, LLC*, 123 FERC ¶ 61,201, at P 10 n.9 (2008)).

3. **Commission Determination**

87. We agree that AMP has raised a material issue with respect to the justness and reasonableness of continuing the current ROE. The current ROE was established in the context of a MISO system-wide ROE based on a proxy group of MISO transmission owners.[37] The Companies' proposal changes the context in which the transmission rates apply. The Companies state that they are no longer combining their revenue requirements and that Duke Kentucky and Duke Ohio are proposing to continue the ROE allowed for MISO transmission owners as members of PJM.[38] These circumstances present neither the same company nor organizational structure for which the current ROE was established. Given the changed circumstances that have occurred since the ROE for the Companies had been established, our preliminary analysis indicates that the Companies' ROE may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Accordingly, pursuant to section 206 of the FPA, we are establishing hearing and settlement judge procedures to investigate the Companies' ROE.

88. Upon the establishment of procedures pursuant to section 206 of the FPA, the Commission must establish a refund effective date that is no earlier than the date of publication of notice of the Commission's intent to institute a proceeding, and no later than five (5) months subsequent to that date. We will establish a refund effective as the date of publication of the issuance of this order.

89. We encourage the parties to make every effort to settle their disputes before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearings in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[39] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[40] The

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[37] *See Midwest Independent Transmission System Operator, Inc.*, 100 FERC ¶ 61,292 (2002).

[38] Duke Ohio, Duke Kentucky, and Duke Indiana were established following the 2005 merger between Duke Energy Corporation and Cinergy Corporation. *See Duke Energy Corp. and Cinergy Corp.*, 113 FERC ¶ 61,297 (2005). Duke Indiana is not proposing to integrate with PJM.

[39] 18 C.F.R. § 385.603 (2011).

[40] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges and a summary of their

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settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions.

90. To allow for stakeholder discussions, we will hold hearing procedures in abeyance pending a report on the disposition of the settlement discussions. By the earlier of October 24, 2012, or thirty days from the date the settlement discussions conclude, the settlement judge is directed to file a report on the settlement process. Based on this report, the Commission will determine whether a further order establishing hearing procedures is necessary. The Commission is also required by section 206 to indicate when it expects to issue a final order. The Commission expects to issue a final order in this section 206 investigation, assuming settlement discussions prove successful, within 180 days from the date the settlement discussions conclude.

E. Waiver Requests

91. We will grant PJM's request for waiver of the $1,500 application fee for Market Buyers applying for PJM membership as a direct result of the Companies' integration into PJM. We find that there is good cause to grant this waiver because the Companies state that the costs that the application fee is intended to cover have already been paid as part of their integration costs. We also find there is good cause to grant PJM's request for waiver of Schedule 9-FERC and will accordingly do so. Finally, we grant the Companies' request for waiver of the Commission's cost support regulations, consistent with our precedent.[41]

The Commission orders:

(A) The Settlement Agreement between the Companies and IMPA is approved, subject to a compliance filing, as discussed in the body of this order.

(B) Duke Ohio and Duke Kentucky tariff revisions are rejected in part, and accepted in part, suspended for a nominal period to be effective January 1, 2012, subject

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background and experience (www.ferc.gov – click on Office of Administrative Law Judges).

[41] *See, e.g., Southern California Edison Co.*, 136 FERC ¶ 61,074 at P 29 (granting waiver of Period I and II data because the company proposed a formula rate using a combination of sources of data including publicly available FERC Form No. 1 data).

to refund, and subject to a compliance filing and a refund report, as discussed in the body of this order.

(C) Within 30 days of the date of this order, Duke Ohio and Duke Kentucky must make a compliance filing and refund report, as discussed in the body of this order.

(D) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act, and by the FPA, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure, and the regulations under the FPA (18 C.F.R., Chapter I), a public hearing shall be held concerning the Companies' return on equity. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (E) and (F) below.

(E) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2008), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

(F) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and with the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report by the earlier of October 24, 2012, or thirty days from the date the settlement discussions conclude, as discussed in the body of this order.

(G) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such a conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.